2020 State of the Market Report For the New York ISO Markets

POTOMAC ECONOMICS

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EXECUTIVE SUMMARY

As the NYISO's Market Monitor Unit ("MMU"), our Core Functions include reporting on market outcomes, evaluating the competitiveness of the wholesale electricity markets, identifying market flaws, and recommending improvements to the market design. We also evaluate the market power mitigation rules, which are designed to limit anticompetitive conduct that would erode the benefits of the competitive markets. The 2020 State of the Market Report presents our assessment of the performance of the wholesale electricity markets administered by the NYISO in 2020. This executive summary provides an overview of market outcomes 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 resources 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 requirements over the long-term by facilitating efficient investment in new resources and retirement of uneconomic resources.

As New York State policy initiatives require the generation fleet to reduce and eventually eliminate carbon dioxide emissions by 2040, the energy, ancillary services, and capacity markets will channel investment toward projects that enable the NYISO to achieve these goals while maintaining reliability at the lowest possible cost.

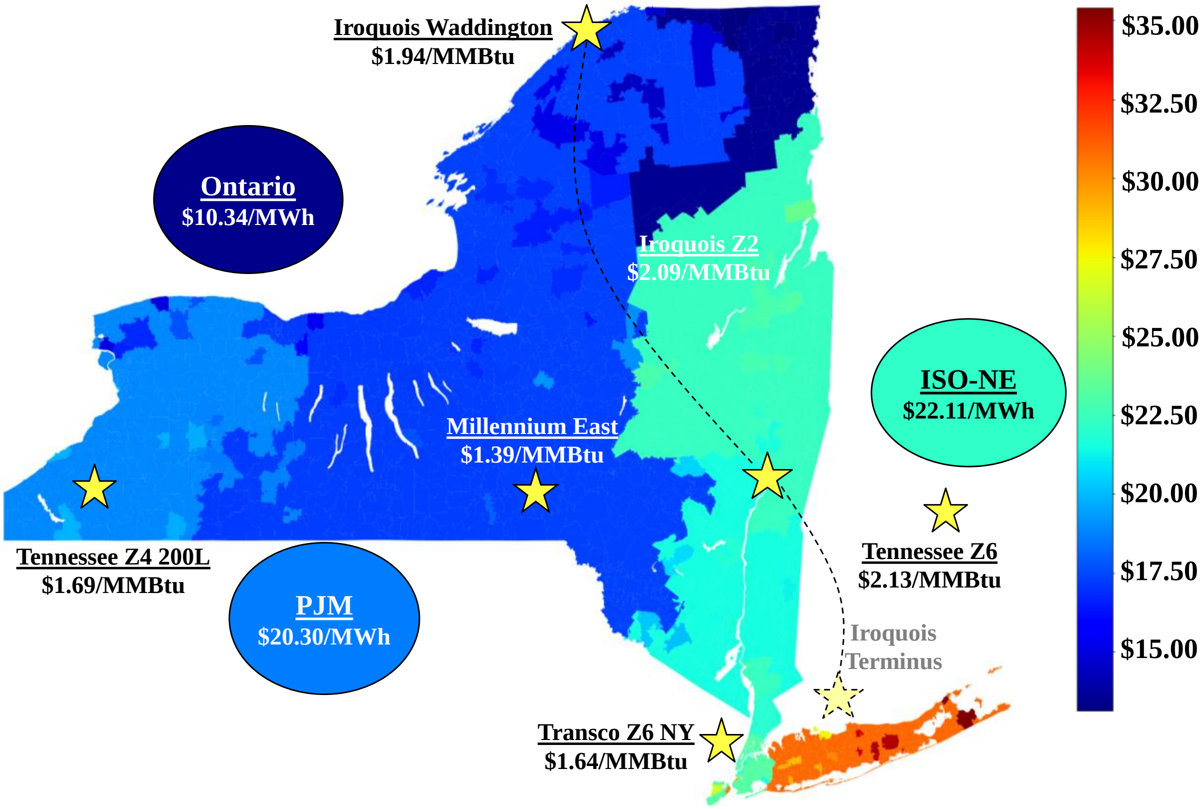
Market Highlights in 2020

The NYISO markets performed competitively in 2020, and the conduct of suppliers was generally consistent with expectations in a competitive market. The mitigation measures were 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 25 to 36 percent across the state from 2019 to 2020 to the lowest levels in over a decade. Gas prices declined because of an unusually mild winter and significantly lower demand during the Covid-19 pandemic. Average load levels also declined in 2020 to historically low levels during the pandemic. Nonetheless, the summer reconstituted peak load rose by 2.5 percent from 2019 because of warmer than average summer weather. (See Sections II.B and II.D for details).

Real-Time Energy Prices, Natural Gas Prices, and Congestion in 2020



Energy Prices and Transmission Congestion

Average energy prices fell 15 to 29 percent across the state from 2019 to 2020 primarily because of lower gas prices and load levels. The impact of the pandemic was larger for commercial customers, so load fell more in downstate regions, which generally reduced congestion from upstate to downstate. Transmission congestion and losses led real-time prices to vary from an average of $13.28 per MWh in the North Zone to $28.03 per MWh in Long Island in 2020. (See II.A)

Congestion revenues collected in the day-ahead market fell 31 percent from 2019, totaling $297 million in 2020, which was the lowest level of congestion revenue since the NYISO began operations. (See Section II.E) The following corridors accounted for most of the congestion:

- Central-East Interface – 39 percent
- West Zone (flowing east) – 19 percent
- Long Island – 17 percent
- New York City – 8 percent

Capacity Market

Continued volatility of the statewide and local capacity requirements led to fluctuations in capacity prices from 2019 to 2020. The statewide requirement increased by over 500 MW and was a key driver of price increases in the "Rest of State" region (i.e., Zones A-F). The local requirements increased by over 300 MW in New York City and decreased by nearly 500 MW in the G-J Locality. Accordingly, the prices in New York City rose by nearly 60 percent, while prices for the G-J Locality fell by 35 percent. (See Section VII.A)

The surplus capacity margin in New York City was relatively low (~4 percent), while areas outside of New York City had large surpluses. Consequently, investment in a new gas turbine similar to the demand curve proxy unit would not be economic at any location in the state. (See VIII.A) 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 2020/21 Capability Year provided just:

- 18 percent of Net CONE outside Southeast New York (Zones A-F);
- 12 percent of Net CONE in the Lower Hudson Valley (Zones G-I);
- 86 percent of Net CONE in New York City (Zone J); and
- 24 percent of Net CONE in Long Island (Zone K).

Although capacity revenues in New York City were close to levels that might be economic for new entry of an H-class frame gas turbine, there remains significant public opposition to permitting of new or repowered fossil-fueled generation.

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 2020 because of low gas prices and load levels. (See VIII.A and VIII.B) We summarize below the results for several types of resources.

Battery Storage. The estimated returns for a 4-hour battery storage project were well below levels that would be needed for a normal rate of return, even after including state incentives. However, the costs of battery systems are projected to decline significantly over the next four years. At the same time, net revenues are likely to rise as higher penetration of intermittent resources leads to increased energy price volatility and higher ancillary services prices. These factors should boost the returns for battery storage projects. Furthermore, several recommended enhancements to the operating reserve markets would help shift investment incentives toward newer more flexible technologies. (See Section VIII.C and Recommendations #2017-1, #2017-2, #2016-1, and #2015-16 in Section XII 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.

Renewable Generation – At recent historical prices and costs, estimated annual returns are high enough for land-based wind to earn a normal rate of return, while other renewable technologies would earn far less than even a regulated rate of return. This is consistent with current trends that nearly all recent investment has been in land-based wind. However, falling costs of solar PV and offshore wind projects suggest that these technologies will be more profitable at many locations in the future. In New York State, state and federal incentives account for the majority of net revenues (65 to 76 percent) for technologies and locations evaluated. (See Section VIII.A)

Existing Steam Turbines. Market revenues of New York City and Long Island steam turbines have generally been lower than their Going Forward Costs in recent years. Existing steam turbines in New York City receive the vast majority of their net revenue from the capacity market and, to a lesser extent, from out-of-market commitments that are required to satisfy local reliability needs. Since the current market design does not adequately reflect the value of energy and ancillary services, it results in higher capacity prices that provide incentives for steam turbines to continue operating. Several of our recommendations would increase the economic pressure on steam units to retire by reducing capacity revenues and out-of-market payments for reliability commitments. (See Sections VIII.B and VIII.C)

Using Markets to Achieve Public Policy Goals

State and federal incentives account for most of the compensation for renewable generation, but the energy and capacity markets still provide critical price signals that differentiate resources based on their value to the power system, encouraging the most economic projects to come forward. The New York Public Service Commission acknowledged the importance of the NYISO's wholesale market signals when it adopted Index REC's as a preferred pricing method. The Index REC structure reduces the risk of widespread price variations from factors such as natural gas prices, while still encouraging renewable generation investors to avoid localized areas that are saturated with particular intermittent technologies. (See Section IX.A)

In our assessment of investment incentives for clean resources, we find that renewable generators entering into long-term contracts for Index RECs in the near future face substantial risks that future clean energy investments will not be sufficiently responsive to market conditions (i.e., that they over-invest in particular technologies in particular regions). Our analysis suggests that current investors will seek significantly higher Index REC payments in the near-term to compensate for the risks presented by future initiatives to develop renewable generation. If future developers receive higher payments, it will impose significant financial risks on current clean generation developers, making it more difficult to achieve public policy goals. Promoting clean energy investment through transparent uniform market signals reduces the associated risks and is likely to achieve policy objectives at a lower overall cost. (See Section IX.B)

BSM rules are not intended to deter states from promoting clean energy investment. However, they help ensure that subsidized investments do not reduce capacity prices substantially below the levels that would occur in a competitive market. The BSM rules should be designed to achieve this objective, while not unreasonably impeding efforts to promote clean energy investment. Removing BSM rules altogether would ultimately raise costs to consumers because, absent a mechanism to mitigate the risk of artificial surpluses, investors in new and existing resources are likely to require higher returns on their capital to compensate for the greater risk associated with future revenues from the NYISO markets. (See Section IX.C)

BSM exemptions for clean resources can be facilitated by the retirement of existing resources so that a balance is maintained between capacity supply and demand. New York State has taken a balanced approach in recent years to decarbonizing the power system by combining incentives to increase zero-emission resources (e.g., energy efficiency, renewables, upstate nuclear generation, and transmission from areas with high renewable potential) with measures to retire coal-fired generation, older downstate peaking units, and the Indian Point nuclear station. We have recommended market improvements that would facilitate the State's energy transition by enabling clean resources to receive BSM exemptions, including (See Section IX.D):

- Part A Test Enhancements – This proposal, which was rejected by FERC and is currently on appeal, would enable Public Policy Resources ("PPRs") to be exempted when retirements (or other factors) reduce the capacity surplus below a certain threshold.
- ICAP Accreditation improvements – These would facilitate new entry of PPRs by recognizing that some resources receive excessive credit for their capacity relative to their marginal reliability value, while ensuring that flexible resources receive appropriate compensation.
- Energy and ancillary services market enhancements – These would increase compensation for flexible resources (e.g., batteries) and increase economic pressure to retire inflexible and inefficient existing units.
- BSM Test Improvements – Our recommendations would improve the implementation of BSM evaluations. These would enable the evaluations to better reflect the costs and revenues of PPRs and provide appropriate amounts of renewable entry exemptions in each region.

Lastly, we evaluate the ability of PPRs to interconnect under the current BSM rules based on projected retirements and the announced public policy initiatives to develop clean resources through 2030.[1] This evaluation demonstrates that there are pathways for these resources to enter without being mitigated. (See Section IX.E) Specifically, we project that the following quantities of state-sponsored resources may interconnect unmitigated by 2030 under conservative assumptions of retirements of existing resources:

- Up to 9 GW of offshore wind in New York City; and
- Up to 900 MW of solar PV in the lower Hudson Valley (i.e., Zones G, H, and I).
- Up to 1,500 MW of battery storage in New York City and up to 430 MW in lower Hudson Valley. These limits will grow considerably if the NYISO moves forward with the market enhancements discussed above and in Section IX.D.

Ultimately, the available Renewable Entry Exemptions are likely to be more than sufficient to accommodate intermittent renewable entry. The BSM rules provide several avenues for other PPRs to obtain exemptions from mitigation and sell capacity. The recommended market design enhancements discussed above will substantially increase the available exemptions for PPRs.

Capacity Market Performance

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. An efficient capacity market compensates individual resources based on the marginal reliability value that the provide to the system. (See Section VII.B)

This report identifies a number areas for improvement in the capacity market. (See Section VII.C) The list includes:

- Inadequate locational signals – The market has just four fixed pricing regions, so when transmission constraints arise within a pricing region, it can lead to inefficient results. A load pocket encompassing Zones A and B has emerged following several changes including coal-fired generation retirements, and the lack of a pricing region for Zones A and B has likely increased the IRM and reduced the LCRs in downstate areas.
- LCR Optimizer uses a flawed objective – This model uses an objective of minimizing consumer payments (rather than investment costs based on the estimated net cost of new entry), which is inefficient and tends to increase the variability of LCRs.
- Some resources are under or over-compensated – The rules for non-conventional technologies (e.g. battery storage and intermittent resources) will not produce capacity compensation that is consistent with their actual marginal reliability value. Likewise, conventional generators with limited availability are also not valued appropriately.

1 This includes retirements of units that will not have an air permit to operate during the Ozone season by 2025.

To address these and other issues with the capacity market, we recommend a number of improvements, the most significant of which are:

ICAP Accreditation Improvements. The NYISO's current methods to convert resources' ICAP to UCAP rely on simple heuristics that do not accurately reflect the marginal reliability value of certain resource types. Current accreditation methods will become more outdated and inaccurate as the resource mix shifts towards intermittent and duration-limited resources. In reality, the marginal reliability value of resources varies according to their availability during hours when capacity margins are tightest – resources with long lead times and low availability tend to provide less reliability value. Additionally, the capacity value of renewables, storage, and demand response resources vary with increased penetration of these resources. We recommend that the NYISO revise its capacity accreditation rules to compensate resources in accordance with their marginal reliability value. (See Section VII.E and Recommendation #2020-3).

Locational Capacity-Pricing Enhancements. The current capacity market design is generally based on the NYISO's planning criteria, but capacity prices are poorly aligned with the marginal reliability value at some locations and for some technologies. Further, it will be difficult for the current market to adapt to changes over the coming decade, including large-scale retirements and entry of new intermittent generation, energy storage, and new transmission. In the long-term, we recommend the NYISO adopt 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, (c) be less burdensome for the NYISO to administer, and (d) reduce the overall costs of maintaining reliability. (See Section VII.D and Recommendation #2013-1c)

Energy and Ancillary Services Market Performance

We evaluate 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 incorporates 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 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 2020, this allowed additional flows of:

- 20 to 34 percent (of the facility seasonal LTE rating) on several 345 kV transmission lines into New York City; and
- 8 to 26 percent on the 138 kV lines into the Greenwood/Staten Island load pockets.

However, reserve providers are not compensated for this type of congestion relief, which can lead to inefficient scheduling in the real-time market and inefficient long-term incentives to invest in flexible resources. Since the New York DEC's Peaker Rule will lead many peakers in New York City to retire in the next four years, efficient market incentives are needed to attract new investment in peaking resources. Otherwise, transmission capability into New York City will be reduced. Hence, we recommend compensating reserve providers for the congestion relief they provide. (See Section X.E and Recommendation #2016-1)

Incentives for Combined Cycle Units Offering Duct-Firing Capacity

Most combined cycle units in New York have a duct burner, which uses supplementary firing to increase the heat energy in a gas turbine's exhaust, making it possible to increase the output of a downstream heat-recovery steam generator. These units are capable of providing 760 MW of duct-firing capacity. This additional output can be offered into the energy market as a portion of the dispatchable range of the unit. Regrettably, a large portion of the duct-firing capacity was not offered into the real-time market because its operational characteristics are not properly recognized by the market scheduling and pricing logic. Therefore, we recommend NYISO consider enhancements to schedule this capacity that takes into account the physical limitations of duct burners. This enhanced scheduling capability could significantly increase the availability of operating reserves, which will become more valuable as older peaking units retire over the next four years. (See Section X.D and Recommendation #2020-1)

Market Performance under Reserve 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. In the future, fluctuations in intermittent output are likely to trigger shortages more frequently. 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 flexible generation to recoup its capital investment. Efficient shortage pricing levels should be set high enough to avoid the need for out-of-market actions and to reflect the risk of load shedding during reserve shortages.

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, such as when local reserve needs can be satisfied by reducing imports to the area and generating more internally (rather than holding reserves on units inside the area). Accordingly, we recommend the NYISO dynamically determine the optimal amount of reserves required to maintain reliability in local areas as well as at the system level. We identify six circumstances when this would provide significant benefits, which will become frequent as the supply mix evolves. (See Section X.A and Recommendation #2015-16)

Second, the operating reserve demand curves are set well below: (a) the cost of OOM actions to maintain reserves during moderate reserve shortages and (b) the reliability value of reserves in reducing the likelihood of load shedding during more significant reserve shortages. The operating reserve demand curve levels will remain below these levels even after the NYISO implements recently approved increases in its shortage pricing incentives. The understated shortage pricing is particular harmful in the NYISO given the more aggressive shortage pricing in neighboring markets. Resources selling into ISO-NE and PJM could receive up to $8,000 per MWh during even slight shortages of 10-minute and 30-minute reserves, while (after the newly approved rules are implemented) the NYISO will set prices between $750 and $3,000 per MWh during *deep* 10-minute and 30-minute shortages. This misalignment in shortage pricing between NYISO and its neighbors will lead to inefficient imports and exports, an increased need for OOM actions, and diminished reliability in New York when conditions are tight in the region.

Therefore, 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 Section X.A and Recommendation #2017-2)

Market Performance under Transmission Shortages

Transmission shortages occur when the flows over a transmission facility exceed its limit, which happens when the NYISO's dispatch model lacks the ability to reduce the flows or the generators that must move to provide the relief are ramp-constrained (i.e., already moving as fast as they can). NYISO experienced such shortages in roughly 7 percent of intervals in 2020, our evaluation of which indicates that the constraint "shadow prices" that set the locational congestion prices in these intervals are generally inefficient for two reasons.

First, the current Graduated Transmission Demand Curve ("GTDC") is not well-aligned with the Constraint Reliability Margin ("CRM") used for many facilities. 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 in the GTDC that corresponds to the CRM of the constraint. This would significantly improve the current GTDC. (See Section X.A and Recommendation #2015-17)

Second, we found that the constraint shadow prices resulting from offline GT pricing were not well-correlated with the severity of transmission constraints. The pricing model in NYISO's real-time market allows assumes that offline GTs are able to respond to dispatch instructions even though they actually cannot. This leads to large differences between modeled flows (that assumes output from the offline units) and actual flows (that recognizes the units are not producing output), compelling NYISO to compensate for these differences by over-constraining transmission in some areas that rely heavily on GTs. For example, the NYISO uses much higher CRMs for key transmission facilities into Long Island, which distorts the generation dispatch and inflates production costs. Therefore, we recommend the NYISO eliminate offline fast-start pricing from the real-time dispatch model. (See Section X.A and Recommendation #2020-2)

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 key findings of our evaluation include:

- The CTS process at the New England interface continued to perform better and produce more savings than at the PJM interface in 2020, largely because of the effects of the much higher fees and uplift costs imposed on transactions at the PJM interface.
- Firms exporting to PJM interface require much larger price spreads (~$7 per MWh) between the markets to profit from the transactions, and they offer much lower quantities.
- The NYISO's export fees NYISO are much more costly than the revenues received from CTS transactions – just $0.6 million in 2020. A lower export fee might result in an higher revenues because CTS transactions would be profitable in many more hours.

It is unlikely that CTS with PJM will function effectively while transaction fees and uplift charges are large relative to the expected value of spreads between markets. Hence, we recommend eliminating (or at least reducing) transaction fees and uplift charges between PJM and NYISO. (See VI.C and Recommendation #2015-9)

Finally, we found that substantial price forecast errors at both interfaces undermine the effectiveness of the CTS processes and the savings they generate. We evaluate factors that contribute to the price forecast errors in the CTS process. (See Section VI.C) Improving the CTS processes will allow it to deliver increasing levels of benefits as renewable output grows in the future. The CTS processes can efficiently balance short-term fluctuations in intermittent generation in New York and neighboring systems.

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 2020, the operation of these lines (in accordance with the wheeling agreements) ***increased*** (a) production costs by an estimated $13 million; (b) CO_2 emissions by an estimated 227 thousand tons; and (c) NOx emissions by an estimated 472 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 will 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 Section X.F and Recommendation #2012-8.)

Out-of-Market Actions

Guarantee payments to generators fell 21 percent from 2019 to $41 million in 2020. The reduction was driven primarily by lower natural gas prices that decreased the commitment cost of gas-fired resources.

New York City. Although New York City accounted for most of the decrease, over $15 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 cover the costs of the units that satisfy these requirements and eliminate the need for the guarantee payments. This would substantially improve price signals, increasing net revenues of a new GT by $19 per kW-year in New York City in 2020. 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 Section X.I and Recommendation #2017-1)

Long Island. In spite of the reduction in other regions, Long Island BPCG uplift rose modestly from 2019 to 2020 – primarily in the area of real-time local BPCG uplift. This was a result of a 61 percent increase in out-of-merit ("OOM") actions in 2020. Nearly $14 million of this local uplift was paid to manage congestion on the 69 kV network and voltage needs on the East End of Long Island on high load days. The inefficient pricing and dispatch associated with these OOM actions have increased in recent years – roughly 65 GWh of oil-fired generation was used to manage 69 kV congestion in 2020. Roughly 35 percent of this could have been avoided through more efficient market dispatch achievable by modeling certain 69 kV constraints and local voltage requirements on Long Island, which we have recommended in prior reports. NYISO began to secure two 69 kV facilities in the market models on April 13, 2021. This is a positive initial step toward more efficient resource scheduling on Long Island, as well as improved price signals and investment incentives. (See Sections V.B and X.I and 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 in the market software. This has led to more efficient management of transmission constraints, more transparent price signals, and improved investment incentives.

Transmission Planning

The NYISO estimates the benefits that would result from new proposed transmission projects in the Economic Planning Process and in the Public Policy Transmission Need evaluation process. 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 Section VII.G and 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.
- Assumed Entry and Exit - Resource inclusion rules used in project evaluations are overly restrictive and effectively exclude projects that are likely to drive congestion, such as contracted policy-driven resources.
- Amortization Period - The Economic Planning Process evaluates proposed projects using a 10-year discount period for its benefit-cost analysis. This discount period is too short to realistically approve economic transmission projects
- 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.

Overview of Recommendations

The NYISO electricity markets generally performed well in 2020 and the NYISO has continued to improve its operation and enhance its market design. Nonetheless, our evaluation identifies areas of potential improvement, so we make recommendations that are discussed throughout this report. The following table identifies the highest priority recommendations and whether the NYISO is addressing them in the 2021 or 2022 Market Project Plans or in some other effort. In general, the recommendations that are designated as "high priority" are those that produce the largest economic efficiencies by lowering production costs of satisfying the system's needs or improving the incentives of participants to make efficient long-term decisions. Most of these high-priority recommendations were made in our 2019 SOM report, but Recommendation #2020-3 is new in this report. A complete list of recommendations and a detailed discussion of each recommendation is provided in Section XII. In total, we have twenty-five outstanding recommendations that are discussed in this section.

High Priority Recommendations in the 2020 SOM Report

<table>
<tr><th>Number</th><th>Section</th><th>Recommendation</th><th>Current Effort</th></tr>
<tr><td colspan="4">Energy Market Enhancements - Pricing and Performance Incentives</td></tr>
<tr><td>2017-1</td><td>VIII.C, X.I</td><td>Model local reserve requirements in New York City load pockets.</td><td rowspan="3">Reserve Enhancements for Constrained Areas project to complete a study of these issues in 2021.</td></tr>
<tr><td>2016-1</td><td>VIII.C, X.E</td><td>Consider rules for efficient pricing and settlement when operating reserve providers provide congestion relief.</td></tr>
<tr><td>2015-16</td><td>X.A, VIII.C</td><td>Dynamically adjust operating reserve requirements to account for factors that increase or decrease the amount of reserves that must be held on internal resources.</td></tr>
<tr><td>2017-2</td><td>VIII.C, X.A</td><td>Modify operating reserve demand curves to improve shortage pricing and ensure NYISO reliability.</td><td>Partially addressed by tariff filing under Ancillary Services Shortage Pricing project in 2021.</td></tr>
<tr><td colspan="4">Capacity Market – Market Power Mitigation Measures</td></tr>
<tr><td>2019-3</td><td>III.C, IX.D</td><td>Modify the Part A test to allow public policy resources to obtain exemptions when it would not result in price suppression below competitive levels.</td><td>Tariff filing in 2020 rejected by FERC; pending judicial review.</td></tr>
<tr><td colspan="4">Capacity Market – Design Enhancements</td></tr>
<tr><td>2020-3</td><td>VII.E</td><td>Revise the capacity accreditation rules to compensate resources in accordance with their marginal reliability value.</td><td></td></tr>
<tr><td>2013-1c</td><td>VII.D</td><td>Implement locational marginal pricing of capacity ("C-LMP") that minimizes the cost of satisfying planning requirements.</td><td></td></tr>
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I. Introduction

This report assesses the efficiency and competitiveness of New York's wholesale electricity markets in 2020.[2] 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 because of the physical characteristics of electricity. This coordination affects not only the prices and production costs of electricity, but also the reliability with which it is delivered.

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.

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2 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."

- 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 market designs provide substantial benefits to the region by:

- Ensuring that the lowest-cost supplies are used to meet demand in the short-term; and
- Establishing transparent price signals that facilitate efficient forward contracting and govern generation and transmission investment and retirement decisions in the long-term. Relying on private investment shifts the risks and costs of poor decisions 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,[3] 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:

- Useful information regarding the value of electricity and cost of production throughout the State; and
- Critical incentives not only for placing new resources where they are likely to be most economical and deliverable to consumers but also for keeping conventional resources that help integrate clean energy resources while maintain system reliability.

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

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

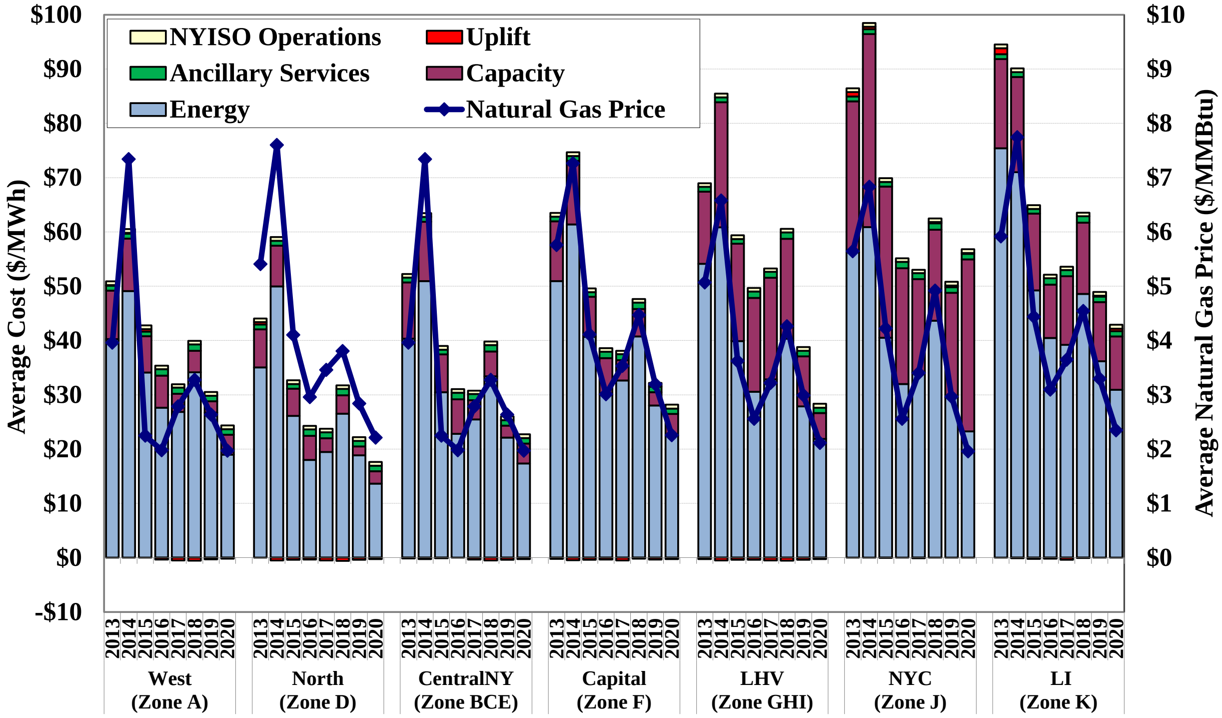
II. Overview of Market Trends and Highlights

This section discusses significant market trends and highlights in 2020. 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. The capacity component is based on monthly spot auction clearing prices and capacity procured in each area, allocated over the energy consumption in that area. All other components are the costs divided by the real-time load in the area.[4]

Figure 1: Average All-In Price by Region
2013-2020



Average all-in prices in 2020 were the lowest observed over the past decade in most zones. All-in prices ranged from as little as $18 per MWh in the North Zone to $58 per MWh in New York City, reflecting year-over-year decreases of 12 to 26 percent across most zones. The exception to this trend was New York City where the all-in price increased by 12 percent from 2019.

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

The decline in all-in prices reflected significant decreases in energy prices across all the seven regions shown. Energy costs, which are generally the largest component of the all-in prices, fell 15 percent to 29 percent from 2019 to 2020. In 2020, energy costs were 70 percent to 78 percent of the all-in price in all regions, except for New York City, where energy costs accounted for only 40 percent of the all-in price. This is because New York City has relatively high capacity costs, which increased substantially from 2019 to 2020.

Over the eight years shown, natural gas price fluctuations were the primary driver of variations in the energy component of the all-in price. Energy prices fell substantially in 2020 because of reductions in natural gas prices and electric load despite the warmer than average summer.[5] Gas prices and load levels were both significantly impacted by the response to the Covid-19 pandemic. The downward impact of the pandemic on the load was more significant in downstate regions, contributing to reduced congestion from upstate to downstate.[6]

In addition to gas prices and load levels, changes in congestion patterns have also significantly affected the energy prices at some locations, especially in Long Island and in the North Zone.

- Long Island continued to experience the highest energy prices of all regions across the state in 2020, consistent with the prior several years. When compared to other regions, Long Island has an older less-fuel-efficient fleet that typically faces higher gas prices and relies more on fuel oil. In 2020, congestion into Long Island increased due to several major outages of transmission facilities, particularly in the summer when load increased because of hotter than usual weather and the shift to higher residential cooling demand.
- The lowest energy costs were observed in the North Zone, where significant wind resources are located. In 2020, congestion out of the North Zone increased as a result of extended outages related to the Moses-Adirondack Smart Path Reliability Project.

Capacity costs in 2020 varied markedly from 2019 levels as average capacity costs:

- Increased 41 to 75 percent in Rest of State regions (i.e. Zones A-F),
- Decreased 48 percent in the Lower Hudson Valley (i.e., Zones G, H, and I),
- Increased 65 percent in New York City, and
- Decreased 10 percent in Long Island.

These changes resulted from a combination of unit entry and retirement, net imports, and changes to administrative parameters used in developing the demand curves. In particular, the capacity costs in New York City rose to an extent that offset year-over-year energy cost reductions, primarily due to an increase in the Locational Capacity Requirements ("LCRs") by

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5 See subsection B for discussion of fuel prices and Section I.D of the Appendix for discussion of load patterns.

6 See Section III of the Appendix for congestion by quarter.

six percentage points. Other notable drivers of changes in year-over-year capacity costs across the state include the retirement of several coal units and the Indian Point 2 nuclear unit and the entry of the Cricket Valley combined cycle plant.[7]

B. Fuel Prices

In recent years, fossil fuel price fluctuations have been the primary driver of changes in wholesale energy prices. Table 1 summarizes natural gas prices in 2019 and 2020 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 (along with a representative gas price index) in seven regions of the state over the same time periods.[8]

Table 1: Average Fuel Prices and Real-Time Energy Prices
2019-2020

	Annual Average			January Average			Rest-of-Year Average		
	2019	2020	% Change	2019	2020	% Change	2019	2020	% Change
Fuel Prices ($/MMBtu)									
Tennessee Z4 200L	$2.26	$1.69	-25%	$2.91	$1.82	-38%	$2.20	$1.68	-24%
Tennessee Z6	$3.26	$2.13	-35%	$7.03	$2.98	-58%	$2.91	$2.05	-30%
Iroquois Z2	$3.04	$2.09	-31%	$6.95	$2.76	-60%	$2.69	$2.03	-24%
Tetco M3	$2.39	$1.59	-33%	$4.35	$2.09	-52%	$2.21	$1.55	-30%
Transco Z6 (NY)	$2.59	$1.64	-36%	$6.02	$2.20	-63%	$2.28	$1.59	-30%
Energy Prices ($/MWh)									
West (TN Z4 200L & Niagara)	$25.49	$17.76	-30%	$33.74	$15.54	-54%	$24.72	$17.97	-27%
Capital (Min of Iroq. Zn 2 & TN Z6)	$26.87	$21.38	-20%	$44.37	$25.26	-43%	$25.24	$21.02	-17%
Lw. Hudson (Tetco M3/Iroq.)	$26.06	$20.28	-22%	$42.01	$22.94	-45%	$24.58	$20.03	-19%
New York City (Transco Z6 NY)	$28.21	$21.97	-22%	$43.78	$28.19	-36%	$26.76	$21.39	-20%
Long Island (Iroq. Zn 2)	$33.33	$28.03	-16%	$48.25	$25.97	-46%	$31.95	$28.22	-12%

Although more than half (over 51 percent in 2020) 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 in 2020 decreased by 25 percent (Tennessee Z4 200L) to 36 percent (Transco Zone 6 (NY)) from 2019, and were the lowest observed in most locations across the state for more than a decade. Gas prices declined due to a combination of lower demand during the Covid-19 pandemic and an unusually mild winter. Over the past decade, the highest energy prices in New York have occurred in the peak winter months when the gas prices

7 See Section VII.A for discussion of key drivers of capacity prices.

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.

are most volatile. However, the 2020 winter was so mild that the monthly average energy prices in a number of regions (e.g. Long Island) peaked during the summer instead of winter.

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 2018 to 2020, 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.[9] 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
2018-2020

Fuel Type	Average Internal Generation						% of Intervals being Marginal		
	GW			% of Total					
	2018	2019	2020	2018	2019	2020	2018	2019	2020
Nuclear	4.9	5.1	4.4	32%	34%	30%	0%	0%	0%
Hydro	3.2	3.3	3.2	21%	22%	22%	44%	43%	45%
Coal	0.1	0.0	0.0	1%	0%	0%	1%	1%	0%
Natural Gas CC	4.9	4.9	5.2	32%	32%	35%	77%	82%	83%
Natural Gas Other	1.3	1.0	1.2	9%	7%	8%	41%	33%	33%
Fuel Oil	0.2	0.1	0.0	1%	0%	0%	3%	2%	3%
Wind	0.5	0.5	0.5	3%	3%	3%	7%	7%	7%
Other	0.3	0.3	0.3	2%	2%	2%	0%	0%	0%

Gas-fired resources accounted for the largest share of internal generation in each year of 2018 to 2020. The share of gas-fired generation increased from 39 percent in 2019 to 43 percent in 2020 due to (a) the entry of new and efficient combined cycle generation in LHV in recent years, and (b) higher output from steam units to offset outages of transmission into Long Island during the second half of the year.

Over half of internal generation in New York was from a combination of hydro and nuclear units in recent years. Average generation from nuclear units fell on average by roughly 700 MW during 2020 because of the retirement of the Indian Point 2. Furthermore, the remaining one GW from the Indian Point 3 unit is scheduled to retire before May 2021. Consequently, the share of generation from nuclear units is expected to decline further in 2021.

9 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).

The last coal-fired unit in the State stopped operating in March 2020.[10] Furthermore, the absence of severe cold weather in 2020 led to very little generation from oil-fired facilities. Most of the oil-fired generation that did occur in 2020 was from steam turbines on Long Island in the East of Northport pocket (during July and August) when the Cross Sound Cable was on outage.

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 and 2020. 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.

Table 3: Peak and Average Load Levels for NYCA
2011 – 2020

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
2020	30.7	31.2	22.5	17.1	0	5	61

In 2020, average load levels were historically low primarily due to the impact of the Covid-19 pandemic-related shutdowns. The average load decreased year-over-year by 3.9 percent. However, the summer reconstituted peak load rose by 2.5 percent from 2019 due primarily to the

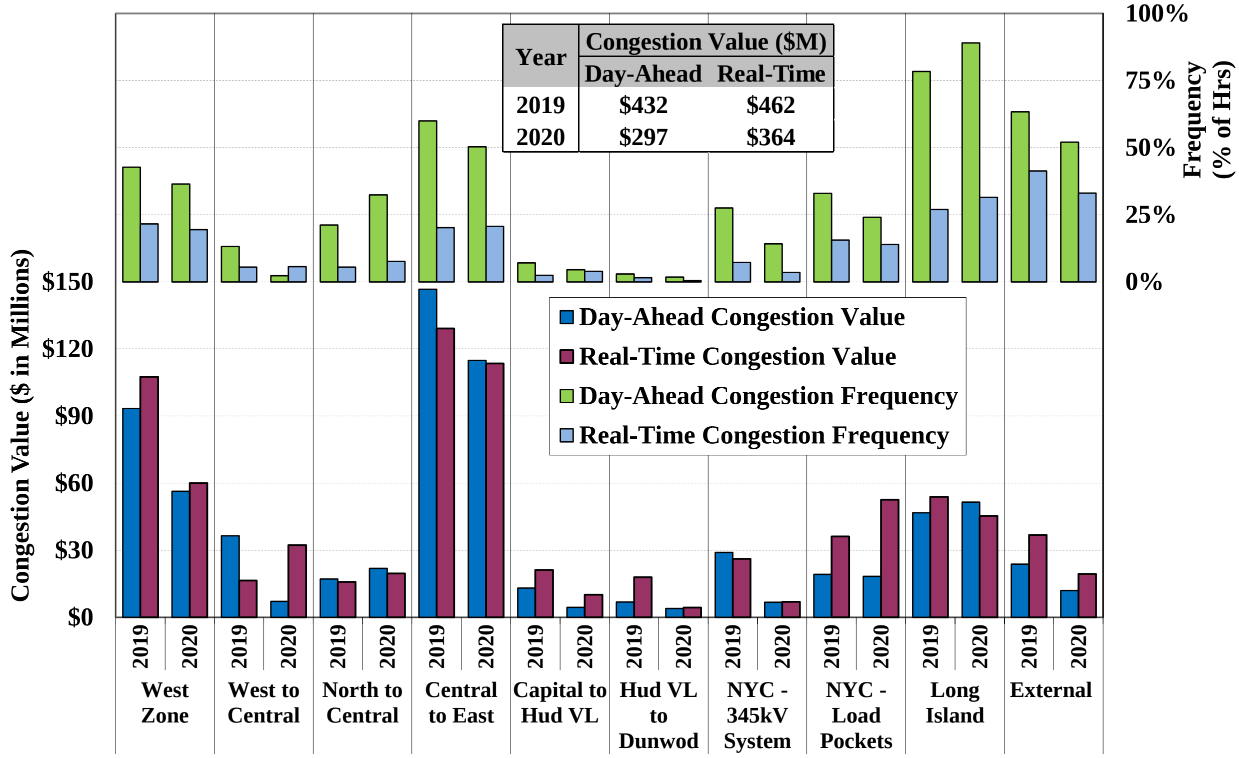
10 See link for NYISO's deactivation assessment for Somerset.

timing of the peak conditions occurring on a weekday in 2020 versus a weekend in 2019. Demand response was activated by utilities on the peak load day in 2020, and reduced the peak load by 1.7 percent.[11]

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.

Figure 2: Day-Ahead and Real-Time Congestion by Transmission Path
2019-2020



The value of day-ahead congestion fell 31 percent to $297 million in 2020, consistent with lower load levels, low natural gas price spreads between regions, and mild winter weather. This was the first year since the inception of the NYISO market where the annual total congestion revenues in the day-ahead market were below $300 million (not adjusting for inflation).

11 Demand response historic activations have not reduced the peak by more than 2.54 percent since 2013.

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

Although congestion decreased in 2020 in most regions, congestion rose modestly on transmission paths from North to Central New York and into and within Long Island because of lengthy outages on major transmission facilities in those regions.

- Congestion from North to Central was driven primarily by the transmission outages taken from May to December for the Moses-Adirondack Smart Path Reliability Project.
- On Long Island, congestion picked up significantly during the second half of the year during the periods with outages on the Cross Sound interface, the Neptune interface, and the 345 kV circuits from upstate to Long Island. Additionally, the COVID-19 pandemic led to higher residential load on Long Island, particularly in the summer months when the weather was warmer than average, contributing to more frequent congestion and higher congestion values.

Other regions saw reduced congestion from 2019 to 2020. The Central-East interface usually accounts for the largest of congestion and continued to do so in 2020 (39 percent of total DA congestion values) despite falling significantly from 2019 levels. Congestion in the West Zone fell sharply (by over 40 percent) from 2019, yet it still accounted for the second largest share of priced congestion in 2020. Besides low gas prices and load levels, the following factors also contributed to lower congestion the West Zone: (a) clockwise loop flows around Lake Erie fell from 2019 to 2020;[13] and (b) the NYISO and PJM incorporated West Zone 115 kV constraints into the M2M process starting in November 2019.

F. Ancillary Services Markets

Scheduling of ancillary services and energy are co-optimized because part of the cost of providing ancillary services is the opportunity cost of not providing energy when it otherwise would be economic to do so. Co-optimization ensures that these opportunity costs are efficiently reflected in Location Based Marginal Prices ("LBMPs") and reserve prices. The ancillary services markets provide additional revenues that reward 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 2019 and 2020.[14]

Average day-ahead prices for all reserve products fell in 2020 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.[15]

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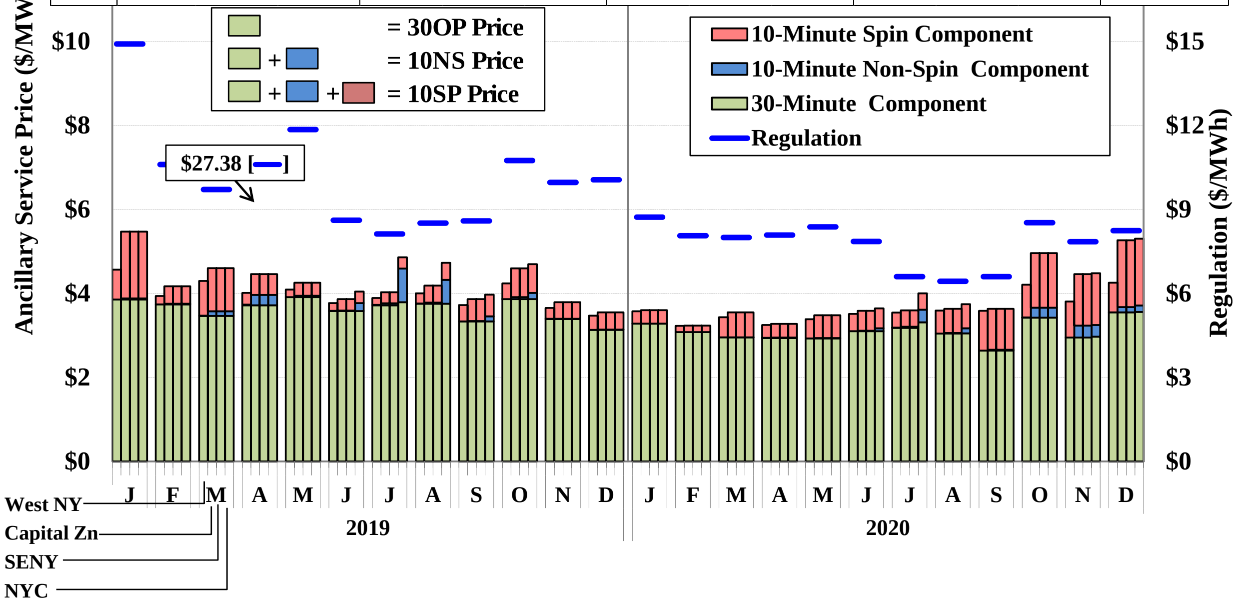
13 See Section III in the Appendix for more details.

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

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

Figure 3: Average Day-Ahead Ancillary Services Prices
2019-2020

	West NY			Capital Zone			Southeast NY			New York City			Regulation
Year	10SP	10NS	30OP	10SP	10NS	30OP	10SP	10NS	30OP	10SP	10NS	30OP	
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	$11.83
2020	$3.62	$3.09	$3.09	$3.86	$3.15	$3.09	$3.86	$3.15	$3.09	$3.91	$3.20	$3.10	$7.78



The price of the NYCA 30-minute reserves accounted for most of the overall day-ahead market reserve procurement costs in 2019 and 2020, with the 10-minute spinning reserves component continuing to be a considerable portion of the total price.

The price premium of the 10-minute spinning product relative to other reserve products increased during 2020 when compared to 2019. This premium (which ranged from $0.53 to $0.81per MWh relative to the 30-Minute product) was largely driven by the increase in 10-minute spin prices during the final four months of 2020, when a number of generators were scheduled for maintenance after deferring such work from the Spring season due to labor and parts supply constraints during the Covid-19 pandemic.[16]

Day-ahead regulation prices fell by 34 percent from 2019 levels; however, removing the effects of April 2019 and its extraordinary prices, the 2020 regulation prices fell by 24 percent from the prior year.[17] Despite the modest increase in regulation requirement in September 2020, prices fell in 2020 due to an increase in the capacity offered by and the significant reduction in the offered prices. [18]

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16 See II.D of the Appendix for discussion of reserve offers.

17 For more on the events in the regulation prices of April 2019, please refer to Section I.F of 2019 SOM report.

18 See II.D of the Appendix for discussion of reserve offers. See link for changes to regulation requirements.

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 2020 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 the use of the market power mitigation measures in New York City and the G-J Locality in 2020.

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 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.

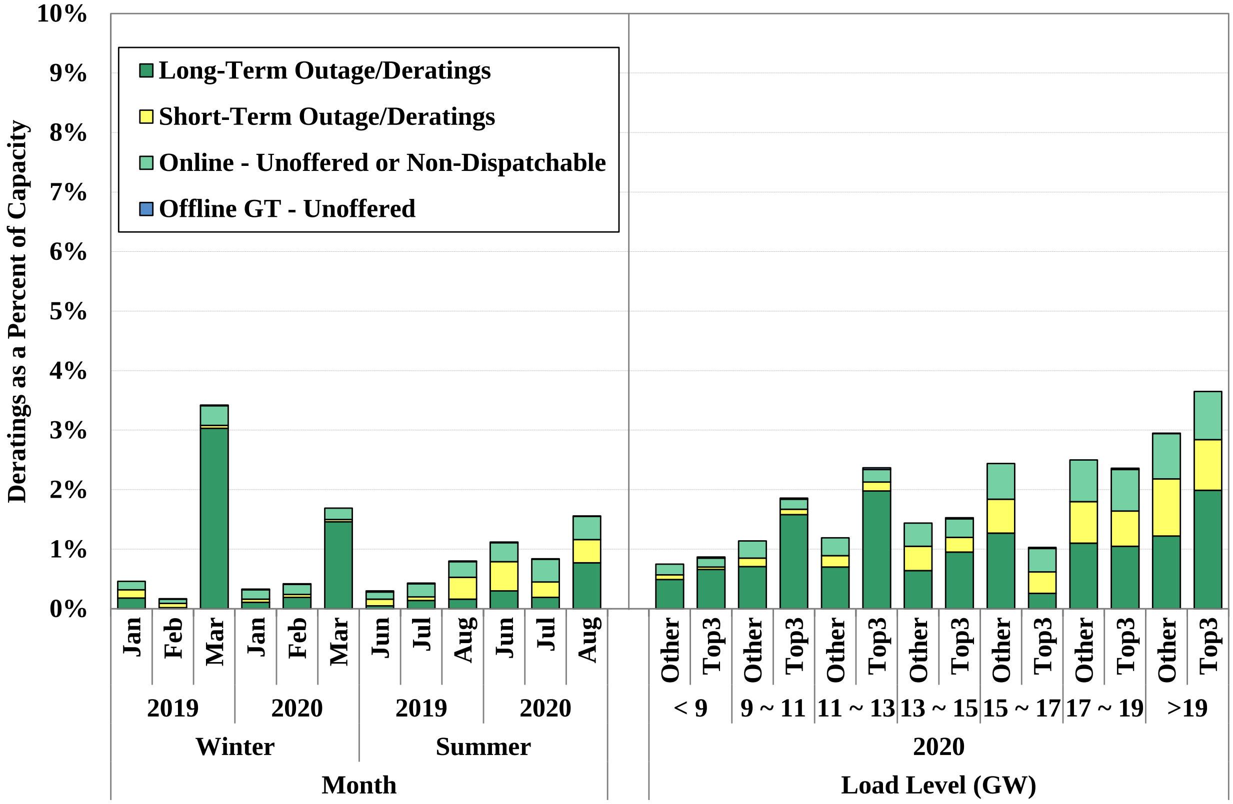
In this competitive assessment, we evaluate potential physical withholding by analyzing economic capacity that is not offered in real-time, either with or without a logged derating or outage. We evaluate potential economic withholding by estimating an "output gap" which is the amount of generation that 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.[19]

Figure 4 and Figure 5 show the two potential withholding measures relative to season, load level, and the supplier's portfolio size.[20] Generator deratings and outages are shown according to whether they are short-term (i.e., seven days or fewer) or long-term.

19 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.

20 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
2019 – 2020



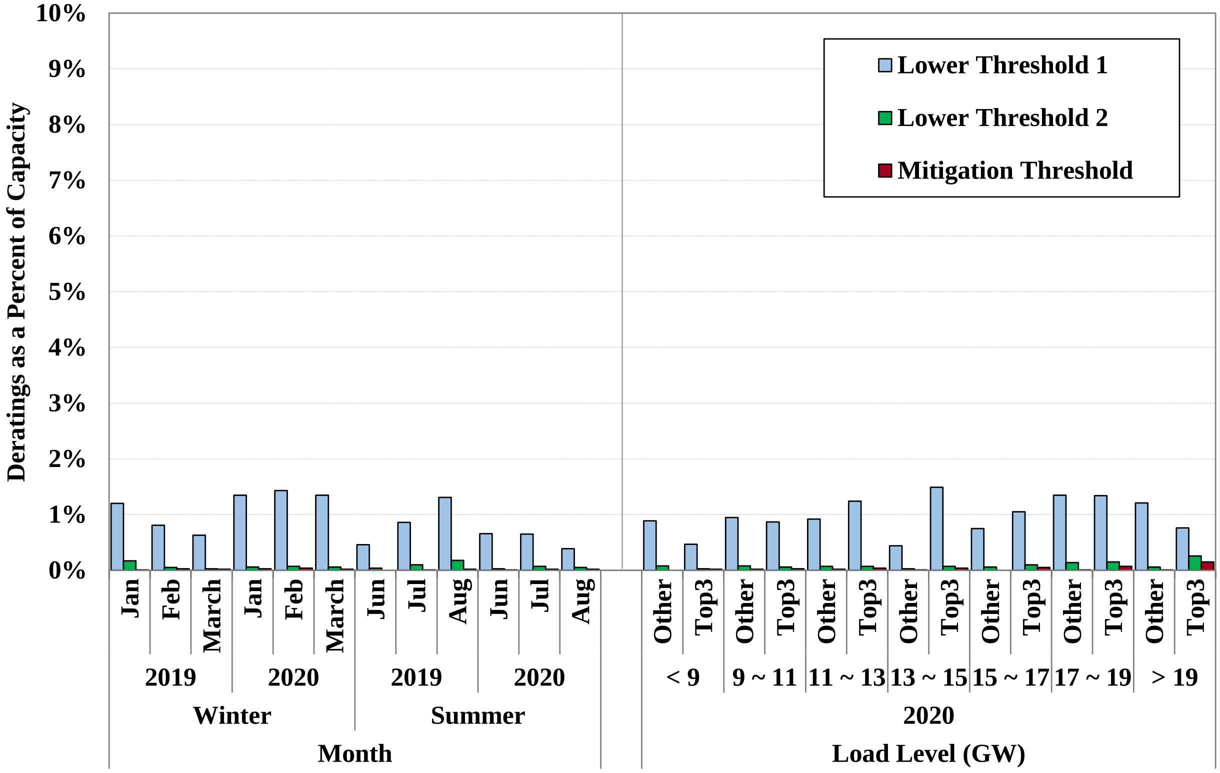
Unoffered economic capacity averaged 1.3 percent of total capacity (DMNC) in NYCA and 1.5 percent in Eastern New York in 2020, up from 2019 levels. Most unoffered economic capacity resulted from long-term outages during shoulder months in spring and autumn. Because of pandemic-related restrictions (e.g. constraints on staffing and travel, among others) in March and April, some generators deferred seasonal maintenance to the fall. Consequently, the amount of capacity on long-term outages fell sharply during March and April but increased from September to November, relative to 2019. In addition, short-term outages accounted for larger share of unoffered economic capacity during 2020, especially during the summer months, but these outages mostly stemmed from forced outages of larger units that did not raise competitive concerns.[21]

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.

21 Low prices likely contributed to an over-estimate of unoffered economic capacity in 2020 because the 25 percent threshold used in 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.

The amount of output gap in Eastern New York remained very low in 2020, averaging 0.02 percent of total capacity at the statewide mitigation threshold and 0.9 percent at the lowest threshold evaluated (i.e., 25 percent above the Reference Level).

Figure 5: Output Gap in Eastern New York
2019 – 2020



The output gap in Eastern New York is usually largest during high load conditions in summer or in peak winter conditions when fuel prices become volatile. In 2020, low load conditions and mild winter weather resulted in negligible amounts of output gap at the mitigation threshold.

Most of the output gap in 2020 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.[22] 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.

22 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.

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.

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.[23]

- 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 real-time markets in 2019 and in 2020. This figure shows that most mitigation occurs in the day-ahead market when most supply is scheduled. Reliability mitigation accounted for 89 percent of all mitigation in 2020, nearly all of which occurred in the day-ahead market. In New York City, the amount of capacity committed for reliability and the frequency of mitigation decreased from 2019 to 2020 because of fewer reliability commitments.[24] The reliability mitigation is critical for ensuring that the market performs competitively because units that are needed for local reliability usually have market power.

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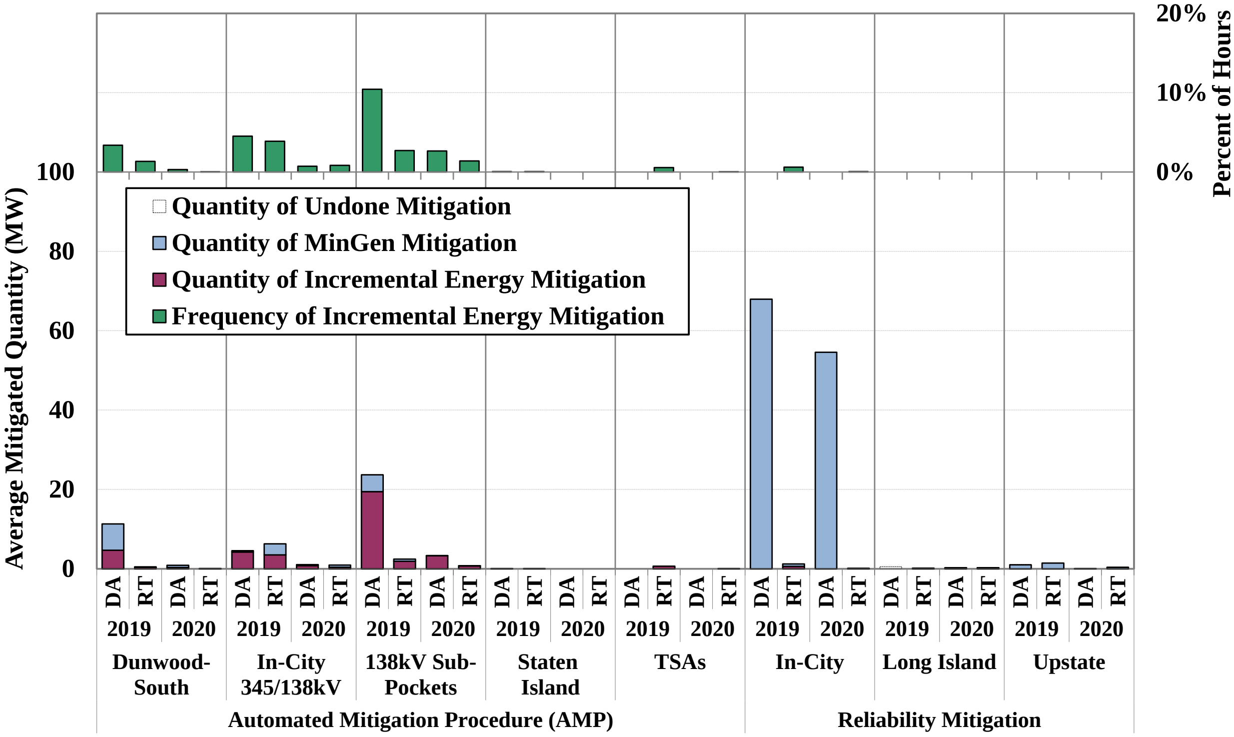
[23] The conduct and impact thresholds used by AMP are determined by the formula provided in the NYISO Market Services Tariff, Section 23.3.1.2.2.1.

[24] See Section X.I for more details on the reduced reliability commitments in New York City.

Figure 6: Summary of Day-Ahead and Real-Time Mitigation
2019 - 2020



AMP mitigation accounted for just 11 percent of total mitigation and was down from 2019 levels in all areas of New York City. AMP mitigation only applies when there is an active transmission constraint. The significant reduction in congestion in New York City load pockets during 2020 resulted in fewer instances when AMP could be applied.

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. This could increase in frequency as the Indian Point units retire and eastern New York becomes more reliant on gas-only and dual-fuel units.

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 2019/20 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.[25]

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.[26]

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 five evaluations.[27]

Given the sensitivity of prices in the Mitigated Capacity Zones, the market power mitigation measures are important for ensuring that capacity prices in these zones are set at competitive levels. This section discusses the application of capacity market mitigation measures in 2020.

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.

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25 See Section XII, Recommendation #2017-4.

26 See NYISO MST, Sections 23.4.5.2 to 23.4.5.6.

27 A new entrant can receive a BSM exemption under the provisions of: (a) Competitive Entry Exemption, (b) Renewable Entry Exemption, (c) Part A Test Exemption, (d) Part B Test Exemption, and (e) Self-Supply Exemption. See MST Section 23.4.5.7.

Application of the Buyer-Side Mitigation Measures

The NYISO performed Mitigation Exemption Tests ("METs") and provided BSM determinations to Examined Facilities that were a part of Class Year 2019 ("CY19"). Table 4 describes each CY19 Examined Facility and the final status of its BSM evaluations.

Five projects in Zone J and seven projects in Zone G, including 37.5 MW of energy storage resources and 173 MW (ICAP) of solar PV resources, were determined to be exempt from an Offer Floor. We reviewed the assumptions and methodology the NYISO utilized in its BSM evaluation of each CY19 Examined Facility, and posted a separate report documenting the results of our review.[28] Overall, we found that the NYISO's BSM determinations in CY19 were made in accordance with the requirements of the Tariff and based on reasonable assumptions.[29]

Table 4: Results of CY19 BSM Evaluations

Examined Facility	Zone	Summer ICAP MW	Unit Type	Status
King's Plaza	J	6	CT	Exempt under Part A and Part B
Spring Creek	J	8	CT	Exempt under Part A
Groundvault Energy Storage	J	12.5	ESR	Exempt under Part A
Stillwell Energy Storage	J	10	ESR	Exempt under Part A
Cleancar Energy Storage	J	15	ESR	Exempt under Part A
Flint Mine Solar	G	100	Solar	Exempt under REE
Danskammer	G	88.9	CC	Exempt under CEE
Greene County I	G	20	Solar	Exempt under REE
Greene County II	G	10	Solar	Exempt under REE
Little Pond Solar	G	20	Solar	Exempt under REE
Greene County 3	G	20	Solar	Exempt under REE
Hannacroix Solar	G	3.23	Solar	Exempt under REE
Monsey 44-6	G	5	ESR	Not exempt, Accepted PCA
Monsey 44-2	G	5	ESR	Not exempt, Accepted PCA
Monsey 44-3	G	5	ESR	Not exempt, Accepted PCA
Cuddebackville Battery	G	10	ESR	Not exempt, Accepted PCA
Yonkers Grid	I	20	ESR	Not exempt, Accepted PCA
Eagle Energy Storage	I	20	ESR	Not exempt, Accepted PCA
KCE NY 2	G	200	ESR	Initial determinations only
Gowanus Repowering	J	574	CT	
Rising Solar II	G	20	Solar	
KCE NY 8a	G	20	ESR	
Blue Stone Solar	G	20	Solar	
KCE NY 14	G	20	ESR	
KCE NY 18	G	20	ESR	

28 See report on *Assessment of the Buyer-Side Mitigation Exemption Tests for the Class Year 2019 Projects*.

29 We identified issues with the Tariff and the NYISO's methodology that, if addressed, could improve the accuracy of the price forecasts and the Unit Net CONE, and/ or would strengthen the provisions of the REE or CEE. See IX.D for an overview of some recommendations. See our report for all recommendations.

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 day-ahead and real-time energy prices (in subsection A), and we analyze virtual trading and other day-ahead scheduling patterns (in subsection B).

A. Day-Ahead to Real-Time Price Convergence

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.[30] These statistics are shown on an annual basis.

Table 5: Price Convergence between Day-Ahead and Real-Time Markets
Select Zones, 2019 - 2020

	Annual Average (DA - RT)			
	Avg. Diff		Avg. Abs. Diff	
Zone	2019	2020	2019	2020
West	-0.1%	0.2%	41.3%	38.7%
Central	2.8%	-0.8%	28.6%	29.3%
North	-0.1%	-5.1%	39.8%	50.2%
Capital	4.2%	-0.7%	26.0%	25.5%
Hudson Valley	3.1%	-0.2%	24.8%	23.7%
New York City	2.4%	-3.3%	25.4%	26.5%
Long Island	-3.0%	-0.5%	37.5%	38.6%

On average, the real-time prices in 2020 were exhibited a small premium (less than one percent) relative to the day-ahead prices in most zones. Relatively low real-time price volatility led to smaller differences between most zones' day-ahead and real-time prices in 2020 when compared to 2019. Unlike most previous years, average real-time prices exhibited a small premium over day-ahead prices in nearly all regions. A small average day-ahead premium is consistent with historical patterns and is generally desirable in a competitive market. While this was true for

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

most of the year, small real-time premiums occurred largely because of real-time price spikes during the cold weather and associated gas price volatility in December 2020.

The regions with the largest real-time premiums were the North Zone (5.1 percent) and New York City (3.3 percent), where the spread increased in 2020 relative to 2019.

- In New York City, the larger real-time price premium was driven by transient real-time congestion in load pockets with limited 5-minute ramping capability. In these pockets, brief transmission shortages occur in real-time if RTC under-forecasts the amount of peaking generation that will be needed to relieve congestion, while such transient price spikes do not occur in the day-ahead market. A well-functioning day-ahead market would schedule additional resources in the load pocket, but the lack of granular virtual trading prevents this market response.
- In the North Zone, real-time price volatility increased in 2020 as a result of reduced transfer capability out of the zone and larger than usual load forecast errors. Outages related to the Moses-Adirondack Smart Path Reliability Project were the key driver of lower transfer capability out of the zone. However, negative real-time pricing events in the North Zone became less severe in 2020, leading to an increase in average real-time prices that reduced incentives for scheduling virtual supply and making day-ahead prices more consistent with expected real-time prices.

The average absolute difference between day-ahead and real-time prices, which is a measure of real-time price volatility, was comparable in 2020 to 2019 levels in all zones except for the North Zone. The price convergence on an absolute basis was better in both 2019 and 2020 when compared to several preceding years. The improved convergence was primarily due to lower load levels, less volatile gas prices, and fewer major transmission outages.

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 an 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 (during specific months) 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 Independence area in the Central Zone. These areas exhibit poor convergence primarily because of differences between the day-ahead and real-time in modeling of transmission facilities, ramp constraints, loop flows, and offer prices of generation.[31]

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 those in real-time. Table 6 shows the average day-ahead schedules of physical load, virtual trades, and virtual imports and exports as a percent of real-time load in 2019 and 2020 for several regions.[32]

Table 6: Day-Ahead Load Scheduling versus Actual Load

By Region, During Daily Peak Load Hours, 2019 – 2020

Region	Year	Bilateral + Fixed Load	Price-Capped Load	Virtual Supply	Virtual Load	Virtual Import	Virtual Export	Net Scheduled Load
West	2019	97.6%	0.0%	-3.3%	21.3%			115.7%
	2020	96.4%	0.0%	-5.7%	22.3%			112.9%
Central NY	2019	119.3%	0.0%	-35.2%	6.0%			90.1%
	2020	118.4%	0.0%	-32.4%	5.9%			92.0%
North	2019	90.9%	0.0%	-40.4%	4.0%			54.4%
	2020	83.9%	0.0%	-28.1%	7.5%			63.3%
Capital	2019	97.1%	0.0%	-9.3%	5.1%			92.9%
	2020	93.2%	0.0%	-10.5%	7.5%			90.2%
Lower Hudson	2019	76.1%	22.0%	-24.4%	10.8%			84.5%
	2020	73.9%	23.6%	-21.4%	12.8%			89.0%
New York City	2019	70.6%	25.9%	-1.6%	5.3%			100.2%
	2020	69.2%	25.1%	-1.1%	7.0%			100.2%
Long Island	2019	97.3%	0.0%	-4.0%	10.2%			103.5%
	2020	93.1%	0.0%	-2.9%	11.9%			102.1%
NYCA	2019	90.0%	11.4%	-13.4%	8.2%	-3.1%	1.0%	94.1%
	2020	88.4%	10.9%	-12.4%	9.7%	-3.2%	1.1%	94.5%

Overall, net scheduled load in the day-ahead market was roughly 94 percent of actual NYCA load during daily peak load hours in 2020, two percentage points less than in 2019 (96 percent). This pattern of net under-scheduling at the NYCA level is driven by several factors that reduce

31 See Appendix section I.G for the node-level analysis.

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

the incidence and severity of high real-time prices, including: (a) the large quantity of available offline peaking generation and available import capability that can respond to unexpected real-time events, (b) out-of-market actions (i.e,, SRE commitments and OOM dispatch) that bring online additional energy and reserves after the day-ahead market, and (c) the tendency for renewable generators to under-schedule in the day-ahead market.

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.

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. In 2020, net scheduled load increased by nine percentage points from the prior year as participants reacted to higher real-time price volatility stemming from extended transmission outages, which reduced transfer capability out of the North zone, but also less-severe negative pricing events.[33]

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 2020, including internal zones and external interfaces.[34] The pattern of virtual trading did not change significantly in 2020 from the prior year, with the exception of the North Zone (as discussed above), and Hudson Valley. Virtual patterns may continue to adjust in the Hudson Valley as the market adjusts to the retirement of the Indian Point nuclear units. 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.

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 $2 million in 2020, indicating that they have generally improved convergence between day-ahead and real-time prices. The average rate of gross virtual profitability was $0.05 per MWh in 2020, much lower than the $0.35 per MWh in 2019. In general, low virtual profitability indicates that the markets are relatively well-arbitraged and is consistent with an efficient day-ahead market.

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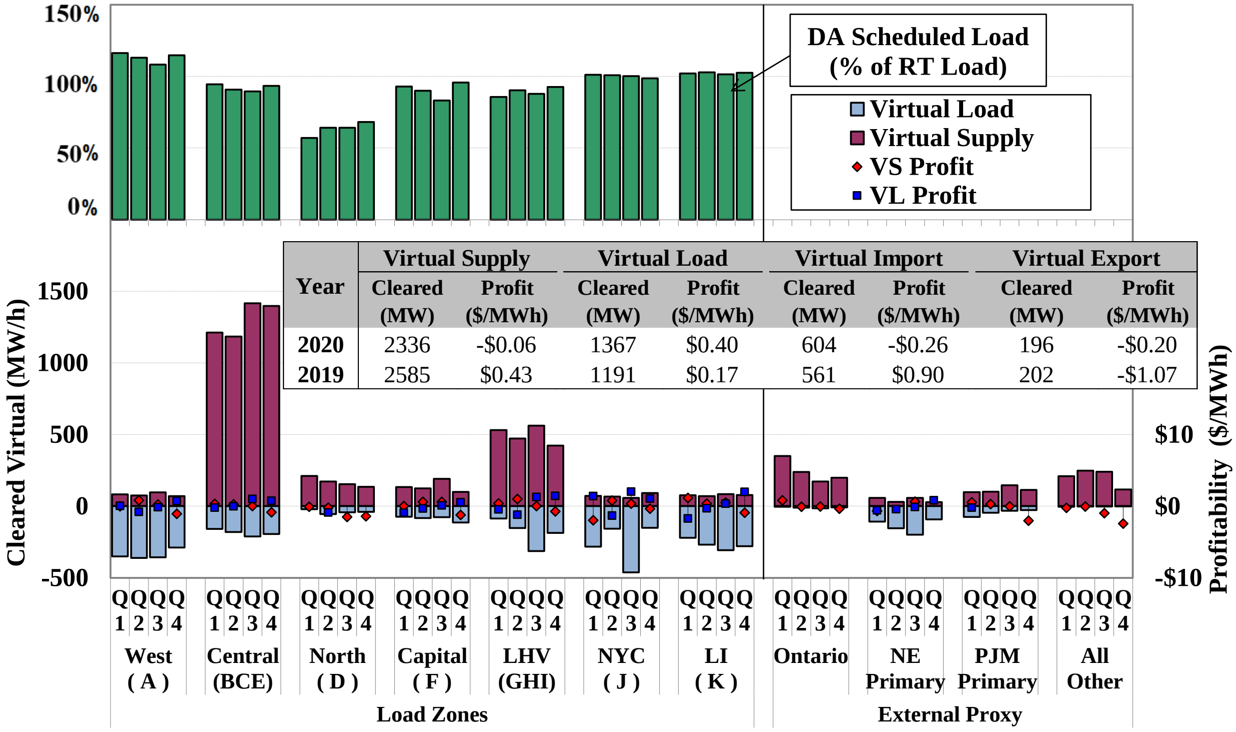
33 See section II.E of the Appendix.

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

Figure 7: Virtual Trading Activity

by Region by Quarter, During All Hours, 2020



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)
2020	2336	-$0.06	1367	$0.40	604	-$0.26	196	-$0.20
2019	2585	$0.43	1191	$0.17	561	$0.90	202	-$1.07

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 2020:

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

In addition, general congestion patterns are summarized in the Market Trends and Highlights section, while the Market Operations section evaluates elements of congestion management.[35]

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.[36] 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. Transmission constraints on the low voltage network 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) are evaluated in subsection B.

Figure 8 evaluates overall congestion by summarizing:

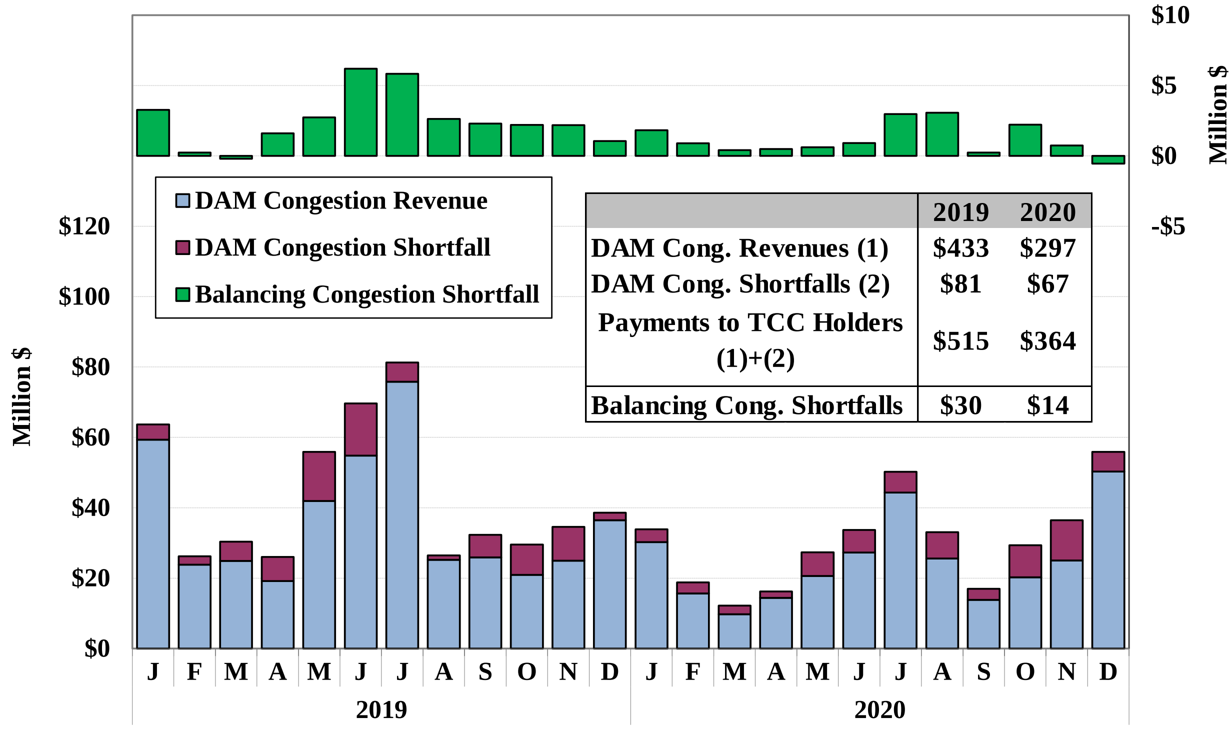
- Day-ahead Congestion Revenues – These are collected by the NYISO when power is scheduled to flow across congested transmission lines in the day-ahead market.

35 The Market Operations section evaluates pricing during transmission shortages (I.A), use of reserves to manage New York City congestion (I.E), and the coordinated congestion management with PJM (I.G).

36 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).

- 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 results when the amount of TCCs sold by the NYISO exceeds the transmission capability of the power system as modeled in the day-ahead market. These shortfalls highlight costly outages and other factors that reduce transmission capability over constrained interfaces.
- 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. These shortfalls highlight outages, modeling inefficiencies, and other operational factors that reduce transmission capability significantly from levels expected in the day-ahead market.

Figure 8: Congestion Revenues and Shortfalls
2019 – 2020



	2019	2020
DAM Cong. Revenues (1)	$433	$297
DAM Cong. Shortfalls (2)	$81	$67
Payments to TCC Holders (1)+(2)	$515	$364
Balancing Cong. Shortfalls	$30	$14

Day-ahead congestion revenues, day-ahead congestion shortfalls, and balancing congestion shortfalls all fell from 2019 to 2020, by 31 percent, 18 percent, and 54 percent, respectively.

Day-Ahead Congestion Revenues

Day-ahead congestion revenues fell from $433 million in 2019 to $297 million in 2020. This was the first year since the inception of the NYISO market when the total annual day-ahead congestion revenues were below $300 million (not taking into account inflation). The unusually low level of congestion in 2020 was primarily driven by:

- Low load levels and infrequent peaking conditions because of the COVID-19 pandemic, which reduced network flows and eased transmission bottlenecks; and
- Low natural gas prices and low gas price spreads across New York, which decreased the redispatch cost of relieving congestion.

In the first three quarters of 2020, congestion fell significantly from the previous year. In the first quarter, weather was very mild, and regional gas prices did not diverge to the extent seen in previous winters, contributing to lower congestion across the Central-East interface. Day-ahead congestion revenues fell $100 million (or 54 percent) from March through July during the height of the pandemic despite temperatures being much warmer than average across much of July.

In the fourth quarter, congestion rebounded because of colder temperatures. Pipelines began issuing OFOs (with tight balancing requirements) in mid-December. The retirement of Indian Point 2 and new entry of the Cricket Valley Energy Center has increased reliance of eastern New York on natural-gas fired generation. On cold winter days, gas-fired capacity in Eastern New York is often unable to obtain fuel or finds it to be prohibitively expensive because of scarcity.

Transmission outages played a key role in congestion patterns in 2020. Fewer costly outages in western New York, across the Central-East interface, and into and within New York City contributed to less congestion in these areas, while the path from north to central New York and Long Island experienced more costly outages. In the North Zone, significant transmission outages were taken from May through the end of the year for the Moses-Adirondack Smart Path Reliability Project. On Long Island, transmission outages and deratings occurred on the Cross Sound interface, the Neptune interface, and the 345 kV circuits from upstate to Long Island for months in the second half of the year. As a result, these two areas saw modest increases in congestion from 2019 to 2020.

Day-Ahead Congestion Shortfalls

Day-ahead congestion shortfalls occur when the day-ahead network capability is less than the capability reflected in TCCs, while day-ahead congestion surpluses (i.e., negative shortfalls) occur when day-ahead schedules across a binding constraint exceeds the amount of TCCs. Table 7 shows total day-ahead congestion shortfalls for selected transmission facility groups.[37] Day-ahead congestion shortfalls fell 18 percent from $81 million in 2019 to $67 million in 2020.

Long Island – These exhibited a dramatic increase in shortfalls, accounting for 35 percent of all shortfalls in 2020. The most significant drivers were:

- The lengthy outage of the Sprainbrook-East Garden City (‘Y49”) 345 kV circuit for most of the fourth quarter, leading to nearly $13 million of shortfalls.

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

- Scheduling of the Pilgrim PAR, which accounted for another $7.5 million of shortfalls, primarily in July and August. Operation of the Pilgrim PAR is limited by transmission constraints on the 69 kV system, but these constraints were not considered in the TCC auctions. Modeling these PAR limitations in the day-ahead market led to more efficient commitment inside the East of Northport load pocket, but it also led associated congestion shortfalls to accrue in the day-ahead market.

Table 7: Day-Ahead Congestion Shortfalls in 2020

Facility Group	Annual Shortfalls ($ Million)
Long Island Lines	$23.3
West Zone Lines	$16.3
North to Central	$13.8
Central to East	$9.2
NYC Lines	$4.9
All Other Facilities	-$0.1

West Zone – These exhibited a 60 percent decrease in shortfalls, but they still accounted for 24 percent of all shortfalls in 2020. Fewer transmission outages was an important driver as these accounted for only $4 million of shortfalls in 2020 down from $10 million in 2019. The remaining $12 million of shortfalls was driven primarily by different assumptions regarding Lake Erie Circulation and other modeling differences between the TCC auction and the day-ahead market.

North to central New York lines – Day-ahead congestion shortfalls accruing on these lines nearly doubled to $14 million in 2020. The primary driver was transmission outages taken from May to December for the Moses-Adirondack Smart Path Reliability Project.

Central-East Interface. The interface accounted for $9 million of shortfalls in 2020, down 53 percent from 2019. The decrease resulted from fewer costly planned transmission outages.

New York City – $5 million of shortfalls accrued on New York City lines in 2020, down 45 percent from 2019 because of fewer costly transmission outages as the COVID-19 pandemic led some regular transmission maintenance projects to be deferred.

The NYISO allocates day-ahead congestion shortfalls that result from transmission outages to specific transmission owners.[38] In 2020, the NYISO allocated 58 percent of the net total day-ahead congestion shortfalls in this manner, up modestly from 2019. 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

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

shortfalls to the responsible transmission owners is a best practice for RTOs because it provides incentives to minimize the overall costs of transmission outages.

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 Schedule 1 charges.[39] Table 8 shows total balancing congestion shortfalls by transmission facility group.[40]

Table 8: Balancing Congestion Shortfalls in 2020 [41]

Facility Group	Annual Shortfalls ($ Million)
West Zone Lines	
Ramapo, A & JK PARs	**$0.7**
Other Factors	**$2.7**
North to Central	**$0.9**
Central to East	
Ramapo, A & JK PARs	**-$1.3**
Other Factors	**$0.5**
TSA Constraints	**$3.4**
Long Island Lines	
Pilgrim PAR	**$2.8**
Other Factors	**$3.9**
External	**$1.0**
All Other Facilities	**$0.7**

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

40 Section III.F 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.

41 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.

Balancing congestion shortfalls were generally small on most days in 2020 but rose notably on a small number of 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 roughly $3.5 million of shortfalls in 2020.

Unplanned and forced outages (including outages and deratings extended beyond the planned period and real-time transfer limit adjustments by operators) were another key driver. For example, a total of $2.2 million of shortfalls accrued on Long Island because of the trip of the Sprainbrook-East Garden City 345 kV ("Y49") line on October 2 and again on December 4.

In the West Zone, balancing congestion shortfalls declined from nearly $14 million in 2019 to $3.5 million in 2020. Although average clockwise loop flows fell in 2020, they continued to be a primary driver of balancing shortfalls in the West Zone. Operation of the NJ-NY PARs (i.e., Ramapo, A, & JK PARs) improved significantly after NYISO worked with PJM to incorporate the West Zone 115 kV constraints in the M2M process beginning in November 2019. The associated shortfalls on West Zone lines fell from $5 million in 2019 to less than $1 million in 2020.

Long Island accounted for nearly $7 million of shortfalls in 2020, 42 percent of which was attributable to inconsistencies between forecasted Pilgrim PAR flows in the day-ahead market and real-time operation. Pilgrim PAR flows have significant impact on both the 138 kV and the 69 kV constraints, but only the 138 kV constraints are currently modeled in the market software. Pilgrim PAR adjustments to manage the 138 kV constraints are often limited by its impact on the 69 kV network, and vice versa. We have recommended that NYISO model 69 kV constraints that are typically relieved by redispatching wholesale generators and/or adjusting PAR-controlled lines.[42] In April 2021, NYISO incorporated two 69 kV constraints on Long Island into the day-ahead and real-time market models which influence the operation of the Pilgrim PAR.[43] These changes should enable the market software to schedule resources to provide congestion management on Long Island more efficiently going forward.

B. Management of Constraints on the Low Voltage Network

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:

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

43 The following two 69 kV constraints are planned for the April 2021 software deployment: Brentwood-Pilgrim and Elwood-Pulaski lines.

- 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 9 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 to 2020 when OOM actions were used in each area.

Table 9: Constraints on the Low Voltage Network in New York [44]
Summary of OOM Days for Managing Constraints, 2018-2020

Area	# of Days with OOM Actions		
	2018	2019	2020
West Zone	260	50	13
Central Zone	35	18	6
North & MHK VL	81	53	26
Capital Zone	130	83	8
Central Hudson	11	34	5
Long Island	121	156	137

The NYISO has greatly reduced the use of OOM actions since 2018 to manage low-voltage transmission constraints by modeling most 115 kV constraints in the day-ahead and real-time markets.[45] This was most evident in the West Zone, where the frequency of OOM actions fell from 260 days in 2018 to just 13 days in 2020. NYISO has a process to routinely assess the need

44 See Section III.D in the Appendix for more details on the use of various resource types in 2020.

45 In addition, the NYISO improved modeling of the Niagara plant to better recognize the different congestion impact from its 115 kV and 230 kV units in December 2018. 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.

and feasibility of securing 115 kV constraints that require OOM actions in the day-ahead and real-time market models. This has helped improve the efficiency of scheduling and pricing in the western New York.

OOM actions in the Capital Zone also fell significantly from 2018 to 2020. The Bethlehem units were frequently dispatched down to manage nearby 115 kV constraints. This has been greatly reduced following the completion of transmission upgrades in mid-2019 and because NYISO has incorporated nearby 115 kV transmission constraints into the market models as needed.

Despite these improvements, OOM actions were often used to manage congestion in:

- North & Mohawk Valley – 26 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 – 13 days – Most of these were to manage congestion on the Gardenville-to-Dunkirk 115 kV lines, which NYISO still does not model in the day-ahead and real-time market software.
- Long Island – 137 days – These are evaluated below in detail.

Unlike 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 2020. Since each pocket is 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 based on the marginal costs of resources used to manage 69 kV constraints.

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 $14 million of BPCG uplift in 2020. However, if OOM resources were able to set the clearing price in 2020, average LBMPs would have:

- Risen 16 percent in the East of Northport load pocket of Long Island; and
- Risen 53 percent in the East End load pocket on Long Island.[46]

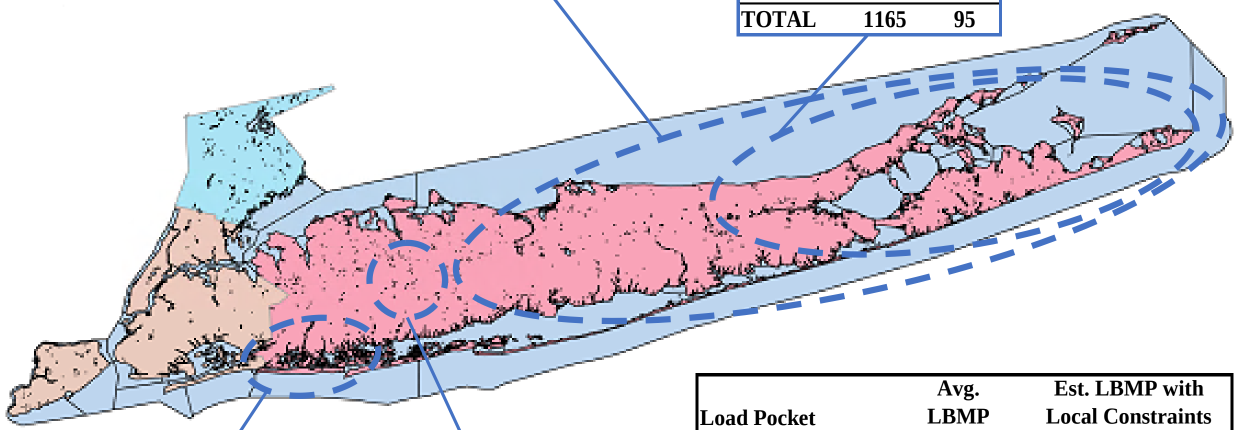
46 Our 2018 and 2019 SOM reports showed comparable estimates for both years, which would have led to a 17 and 12 percent increase in average LBMPs in East of Northport load pocket in 2018 and 2019, respectively, and 44 and 53 percent in the East End load pocket.

Figure 9: Constraints on the Low Voltage Network in Long Island

Frequency of Action and Price Impact, 2020

East of Northport	#Hours	#Days
69kV	480	51
138kV	1336	124
TOTAL	1529	132

East End	#Hours	#Days
69kV	114	13
138kV	2	1
TVR	1115	90
TOTAL	1165	95



Load Pocket	Avg. LBMP	Est. LBMP with Local Constraints
Brentwood	$27.97	$28.54
East End	$31.45	$48.13
East of Northport	$30.68	$35.62
Valley Stream	$29.15	$33.70

Brentwood	#Hours	#Days
69kV	312	54
138kV	0	0
TOTAL	312	54

Valley Stream	#Hours	#Days
69kV	1050	79
138kV	4513	284
TOTAL	5040	291

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. The NYISO made an improvement in mid-July of 2020 to forecast Pilgrim PAR flows more accurately in the day-ahead market, which helps commit generation more efficiently inside the pocket. However, Pilgrim PAR flows could be forecasted more accurately by modeling the 69 kV circuits that limit the operation of the PAR.

Oil-fired generation was used to manage 69 kV and 138 kV constraints in the East of Northport Load Pocket in 628 hours on 91 days in 2020. The vast majority of this oil-fired generation occurred in July and August on high load days during an outage of the Cross Sound Cable. Total output was 89.3 GWh in 2020, of which 73 percent was to manage congestion on these 69 kV constraints. In 51 percent of these hours (320 hours), the amount of unscheduled low-cost resources (i.e., unscheduled gas-fired capacity and/or CSC import capability) exceeded the amount of oil-fired generation, implying that the oil-fired generation would likely have been avoidable during these hours had the 69 kV constraints been secured in the market software.

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 NYISO model 69 kV constraints and East End TVR needs (using surrogate thermal constraints) in the market software.[47] NYISO began to secure two 69 kV facilities in the market models on April 13, 2021.[48] This is a positive move towards more efficient resource scheduling and pricing on Long Island.

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 2019/20 and Summer 2020 Capability Periods (i.e., November 2019 to October 2020). Table 10 summarizes TCC cost and profit for the evaluation period separately for inter-zonal and intra-zonal TCCs.[49]

- The *TCC Profit* measures the difference between the *TCC Payment* and the *TCC Cost*.
- The *TCC Cost* measures what market participants paid to obtain TCC rights from the TCC auctions. For a particular path, the *TCC Cost* is equal to the purchased TCC MW multiplied by the TCC price for that path.
- The *TCC Payment* is equal to the TCC MW between two points multiplied by the congestion cost difference in the day-ahead market between the two points.

Market participants purchasing TCCs in the auctions covering the 12-month period from November 2019 to October 2020 netted a total *loss* of $81 million. Overall, the net profitability

47 See Recommendation #2018-1.

48 The following two 69 kV constraints are planned for the April 2021 software deployment: the Brentwood-Pilgrim line and the Elwood-Pulaski line.

49 Appendix Section III.H describes how we break each TCC into inter-zonal and intra-zonal components.

for TCC holders in this period was *negative* 33 percent (as a weighted percentage of the original TCC prices), compared to *negative* 18 percent in the previous 12-month period.

In this reporting period, TCC buyers netted an average *loss* of 39 percent on the inter-zonal transmission paths and an average *loss* of 19 percent on the intra-zonal paths. Low natural gas prices and unexpectedly low load levels because of the COVID-19 pandemic led to unusually low congestion in 2020, which was not anticipated by market participants, As a result, TCC buyers netted a loss on most transmission paths.

Table 10: TCC Cost and Profit

Winter 2019/20 and Summer 2020 Capability Periods

	TCC Cost ($ Million)	TCC Profit ($ Million)	Profit as a Percent of Cost
Intra-Zonal TCC			
West Zone	$23	-$6	-27%
Central Zone	$18	-$9	-49%
New York City	$11	-$2	-19%
Long Island	$8	$8	100%
All Other	$8	-$4	-46%
Total	**$68**	**-$13**	**-19%**
Inter-Zonal TCC			
Other to West Zone	$53	-$14	-26%
Other to Central New York	$35	-$9	-26%
UpState to New York City	$28	-$18	-63%
New York to New England	$33	-$15	-46%
All Other	$27	-$12	-44%
Total	**$176**	**-$68**	**-39%**

TCC buyers netted the largest loss of $21 million on transmission paths sinking at New York City (from a $39 million purchase cost). Commercial load in New York City and associated congestion was greatly reduced by the pandemic. TCC buyers also netted a $20 million loss from a $75 million purchase cost on transmission paths sinking at the West Zone. This coincided with a 40 percent reduction in day-ahead congestion in the West Zone.

Conversely, TCC buyers actually profited on transmission paths sinking on Long Island, netting a $10 million profit from a $10 million purchase cost. This coincided with a modest increase of 10 percent in day-ahead congestion on Long Island from 2019 to 2020, driven primarily by: (a) unexpected lengthy transmission outages at the Cross Sound Cable interface, the Neptune interface, and of the Y49 line; and (b) higher residential load in Long Island resulting from the pandemic.

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. Unexpected congestion-driven events, such as lengthy unplanned outages and large variations in load patterns, are often a key driver of TCC profitability. 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.

NYISO 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.[50,51] Hence, NYISO's total import capability is large relative to its load, making it important to schedule the interfaces efficiently.

A. Interchange between New York and Adjacent Areas

Table 11 summarizes the net scheduled imports from neighboring control areas in 2019 and 2020 during peak (i.e., 6 am to 10 pm, Monday through Friday) hours.[52] Total net imports from neighboring areas averaged 2.4 GW during peak hours in 2020, down 17 percent from 2019.

Table 11: Average Net Imports from Neighboring Areas
Peak Hours, 2019 – 2020

Year	Quebec	Ontario	PJM	New England	CSC	Neptune	1385	VFT	HTP	Total
2019	1,327	686	491	-809	154	610	37	224	179	2,898
2020	1,258	750	367	-965	89	509	52	179	164	2,403

Controllable Interfaces

Net imports from neighboring areas satisfied 27 percent of Long Island's demand in 2020. This was down modestly from prior years because of lengthy transmission outages. The Neptune line

50 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.

51 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 X.F and X.G.

52 Figure A-65 to Figure A-68 in the Appendix show more detailed on net scheduled interchange between New York and neighboring areas by month by interface.

was partially derated to 375 MW from September to December and the Cross Sound Cable was completely out of service from August to December. Net imports over the Cross Sound Cable and the 1385 line declined in the winter when natural gas prices in New England were higher than on Long Island and rose in other months, while the Neptune line was typically scheduled to the full capability during daily peak hours. Lower net imports to Long Island also contributed to higher congestion within Long Island.[53]

Net imports to New York City over the Linden VFT and the HTP interfaces fell by 15 percent from 2019 to an average of 340 MW during peak hours in 2020. The decrease reflected 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 17 percent from 1,695 MW in 2019 to 1,410 MW in 2020 in peak hours. Net imports from Quebec to New York accounted for 89 percent of net imports across the primary interfaces in 2020. Variations in Quebec imports are normally caused by transmission outages on the interface.[54]

Average net imports from Ontario rose modestly (by 65 MW) from 2019 to 2020 even though energy price spreads between Ontario and NYISO markets became smaller in 2020. This was driven partly by less congestion from west-to-east through the West Zone.

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 19 percent from 2019 to 2020, reflecting fewer lengthy transmission outages at the interface in 2020.[55]

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

53 See Section IV.A in the Appendix for discussion in more details.

54 Imports from Quebec were high in most months of 2020 but fell notably in several shoulder months (e.g., March, November) because of transmission outages.

55 In 2019, the Long Mountain-Pleasant Valley 345 kV line was OOS from early March to late May, reducing the NY/NE interface limit to around 700 MW. There were no similar lengthy outages in 2020.

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 began operating in April 2012, large fluctuations in loop flows are still common.[56] Like prior years, we observe a strong correlation between the severity of West Zone congestion and the magnitude and volatility of loop flows in 2020, although average clockwise loop flows fell in 2020.[57]

Several market enhancements have been implemented in recent years to improve the efficiency of congestion management in the West Zone, which has helped limit the effects of loop flows:

- In December 2018, the NYISO: (a) started to incorporate 115 kV constraints in the day-ahead and real-time markets; and (b) improved modeling of the Niagara Plant.
- In November 2019, the NYISO and PJM started to incorporate 115 kV constraints into the M2M JOA process.

In addition, to better manage the effects of loop flows, the NYISO:

- Used a higher CRM of 60 MW on the Niagara-Packard 230 kV lines and the Niagara-Robinson Rd 230 kV line. This is much higher than the default 20 MW that is used for most of other constraints.
- Reduced transmission scheduling limits in real-time when necessary to ensure line flows remained at acceptable physical levels when loop flows are clockwise or swung rapidly in the clockwise direction.
- 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). However, it would be better to modify the market software to allow adjustments that vary according to loop flows and other conditions at the time RTC initialized.[58]
- Relocated the electrical location of the IESO proxy bus in its scheduling models from the Bruce 500 kV station to the Beck 220 kV station (near the Niagara station in New York) on April 21, 2020. This was intended to provide a more accurate representation of the effects of interchange with Ontario on loop flows.

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 C; (b) the transient congestion (along with other factors that are not explicitly modeled in the dispatch software) in Section X.H; and (c) the day-ahead and balancing congestion shortfall uplift in Section V.A.

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56 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.

57 See Section III.E in the Appendix for more details.

58 See Section V.E in the Appendix of our 2019 State of the Market Report for more details.

C. Coordinated Transaction Scheduling with ISO-NE and PJM

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 that is used at the interfaces with Ontario and Quebec and between Long Island and Connecticut.

- 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 better 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 primary PJM and ISO-NE interfaces, showing the average amount of bids at each interface in peak hours (i.e., HB 7 to 22) from 2018 to 2020.[59] Only CTS bids are allowed at the ISO-NE interface, while CTS bids and LBMP-based bids are used at the PJM interface. 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.[60]

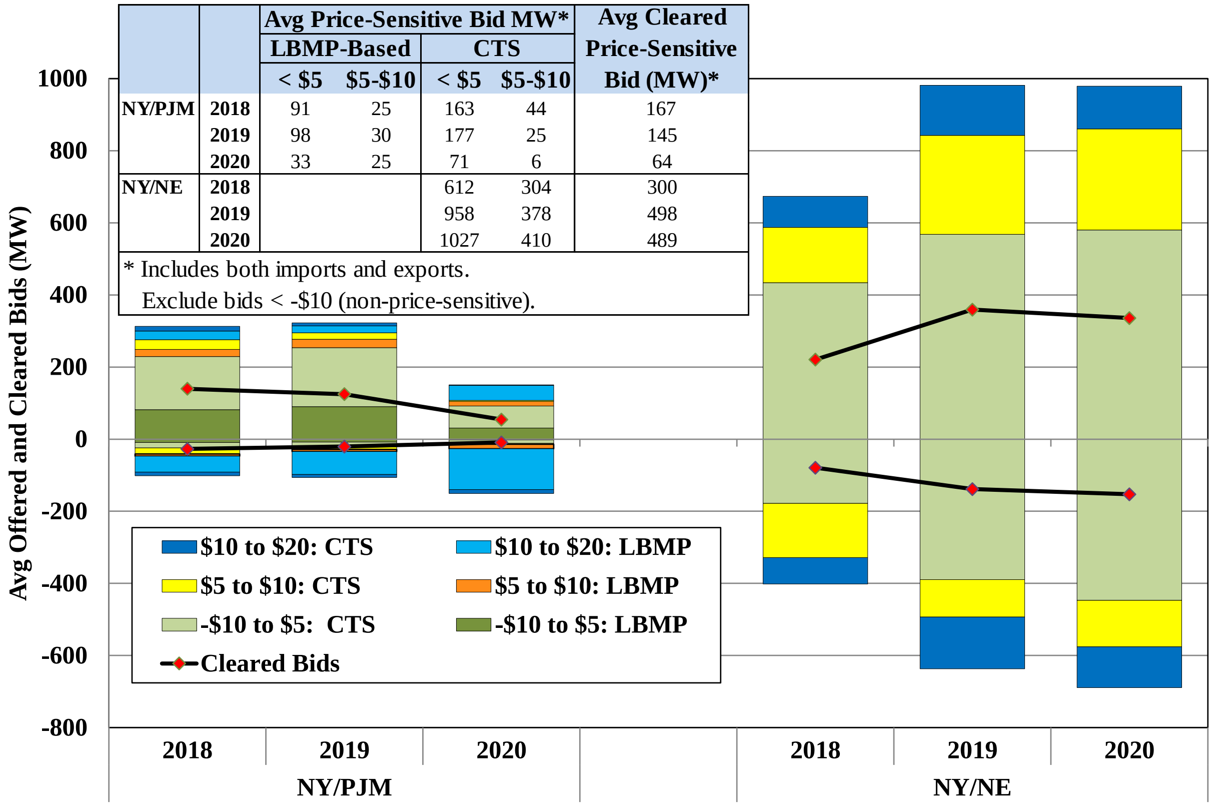
The average amount of price-sensitive bids at the PJM interface was significantly lower than at the New England interface in each year from 2018 to 2020. An average of roughly 865 MW (including both imports and exports) was offered between -$10 and $5 per MWh at the New England interface over this three-year period, substantially higher than the 210 MW offered in the same price range at the PJM interface. Likewise, the average amount of cleared price-sensitive bids at the New England interface nearly tripled the average amount cleared at the PJM interface over this three-year period.

59 Figure A-70 in the Appendix shows the same information by month for 2020.

60 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.

Figure 10: Average CTS Transaction Bids and Offers

PJM and NE Primary Interfaces – 2018-2020



		Avg Price-Sensitive Bid MW*				Avg Cleared Price-Sensitive Bid (MW)*
		LBMP-Based		CTS		
		< $5	$5-$10	< $5	$5-$10	
NY/PJM	2018	91	25	163	44	167
	2019	98	30	177	25	145
	2020	33	25	71	6	64
NY/NE	2018			612	304	300
	2019			958	378	498
	2020			1027	410	489

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

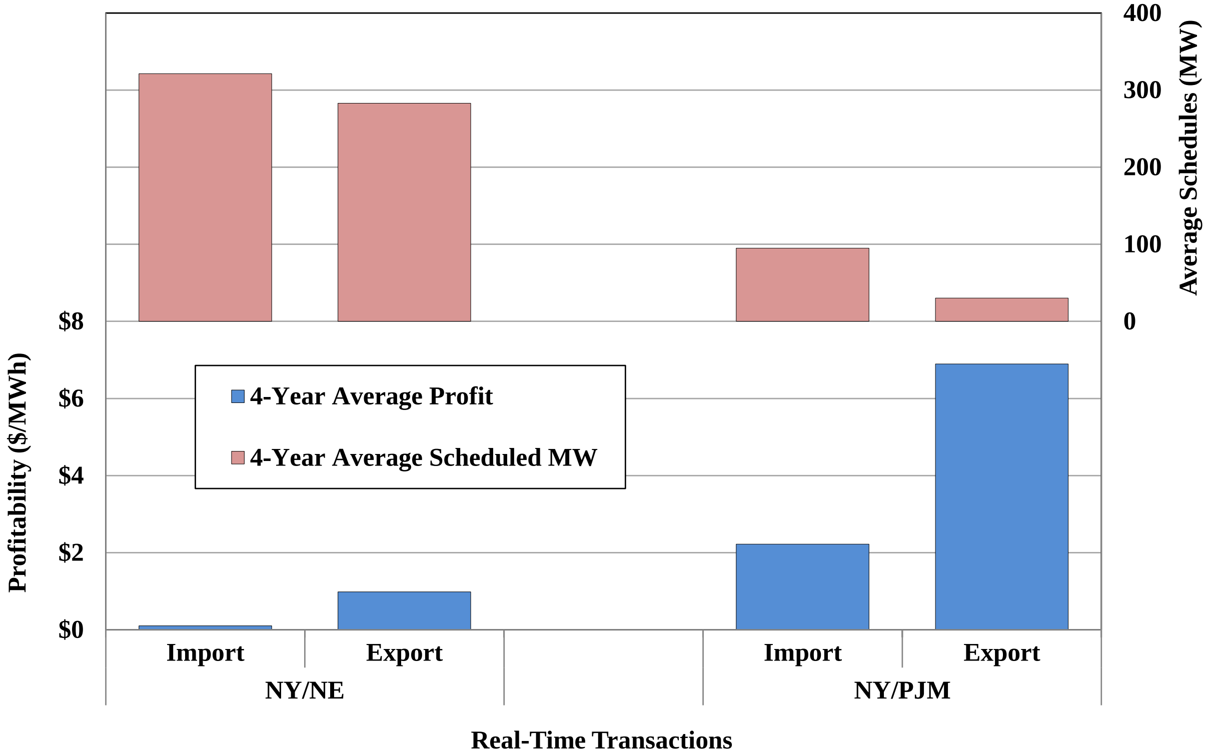
The differences between the two CTS processes are largely attributable to the large fees that are imposed at the PJM interface, while there are no substantial transmission charges or uplift charges on transactions between New York and New England. The NYISO typically charges physical exports to PJM at a transmission rate ranging from $5 to $8 per MWh. As a result, almost no CTS export bids were offered at less than $5 per MWh at the PJM border. On the other side, PJM also charges physical imports and exports a transmission rate that averages less than $2 per MWh.[61] The amount of real-time exports scheduled price-sensitively at the PJM border averaged just 19 MW over the three-year period from 2018 to 2020, much lower than the average amount of real-time imports scheduled price-sensitively (roughly 106 MW). This was primarily because fees were significantly higher on transactions scheduled from NYISO to PJM than the opposite direction. Therefore, 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.

61 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. In addition, PJM charges "real-time deviation" (which include imports and exports with a real-time schedule that is higher or lower than day-ahead schedule) at a rate that averages less than $1/MWh.

Figure 11 examines the average gross profitability of scheduled real-time transactions (not including fees mentioned above) and average scheduled quantity at the two CTS interfaces from 2017 to 2020. [62] The gross profitability of scheduled real-time transactions (including both imports and exports) averaged roughly $0.6 per MWh over the four-year period at the primary New England interface, indicating this is generally a low-margin trading activity because firms are willing to schedule when they expect even a small price differential.

Figure 11: Gross Profitability and Quantity of Scheduled Real-Time External Transactions

PJM and NE Primary Interfaces, 2017-2020



At the PJM border, the average gross profitability was moderately higher for scheduled imports and far higher for scheduled exports. This reflects that market 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. Consequently, they schedule much lower quantities, particularly exports from NYISO to PJM, which are required to pay the highest transaction fees. These results demonstrate that imposing large transaction fees on low-margin trading provides a strong disincentive to schedule transactions, dramatically reducing trading volumes, liquidity, and even revenue collected from the fees.

62 Real-time external transactions here refer to external transactions that are only scheduled in the real-time market (excluding transactions scheduled in the day-ahead market and flow in real-time).

We recommend eliminating (or at least reducing) these charges at the interfaces with PJM for several reasons.[63] First, as the resource mix in New York changes to include more intermittent renewable resources, it will be important to schedule exports to neighboring regions when excess renewable generation cannot be delivered to consumers in New York. A better-performing CTS will facilitate more efficient scheduling between markets, which is important for successful integration of these resources. High fees will lead to more frequent periods when renewable generation will be curtailed because it cannot be delivered to consumers.

Second, it is unreasonable to assign the same transmission charges to price-sensitive exports as are assigned to network load customers. These transmission charges recoup the embedded cost of the transmission system which is planned for the projected growth of network load, but price-sensitive exports likely contribute nothing to the cost of the transmission system.

Third, we estimate that NYISO collected roughly $0.6 million in export fees from real-time exports to PJM in 2020, while PJM collected $1.2 million in export fees from real-time exports to NYISO. This suggests that a lower export fee could result in an overall higher collection of fees because it would allow CTS transactions to be profitable under a wider range of conditions.

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.[64]

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 2020, this adjustment (from our estimated hourly schedule) occurred in 78 percent of intervals at the New England interface, compared to just 30 percent at the PJM interface. However, inaccurate price forecasts reduced the savings that were actually realized. We estimated that in 2020,[65]

- $3.4 million of potential savings were realized at the New England interface; and
- $0.3 million were realized at the PJM interface.

The actual production cost savings fell modestly at the New England interface from 2019, reflecting smaller differences in energy prices between the two markets partly because of lower

63 See Recommendation #2015-9.

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

65 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.

loads and gas prices in 2020. On the other hand, the actual production cost savings at the PJM border was much lower ($0.3 million) in 2020 partly because of price forecast errors. Of all price forecasts at the two CTS interfaces, PJM's price forecasts were still the worst in 2020.

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 2020. 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.[66] 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 2020.[67] Similar to our findings from previous reports, our evaluation identified three primary groups of factors that contributed most to RTC price forecast errors in 2020.[68]

First, transmission network modeling issues were the most significant category, accounting for 43 percent of the divergence between RTC and RTD in 2020 compared to 42 percent 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,

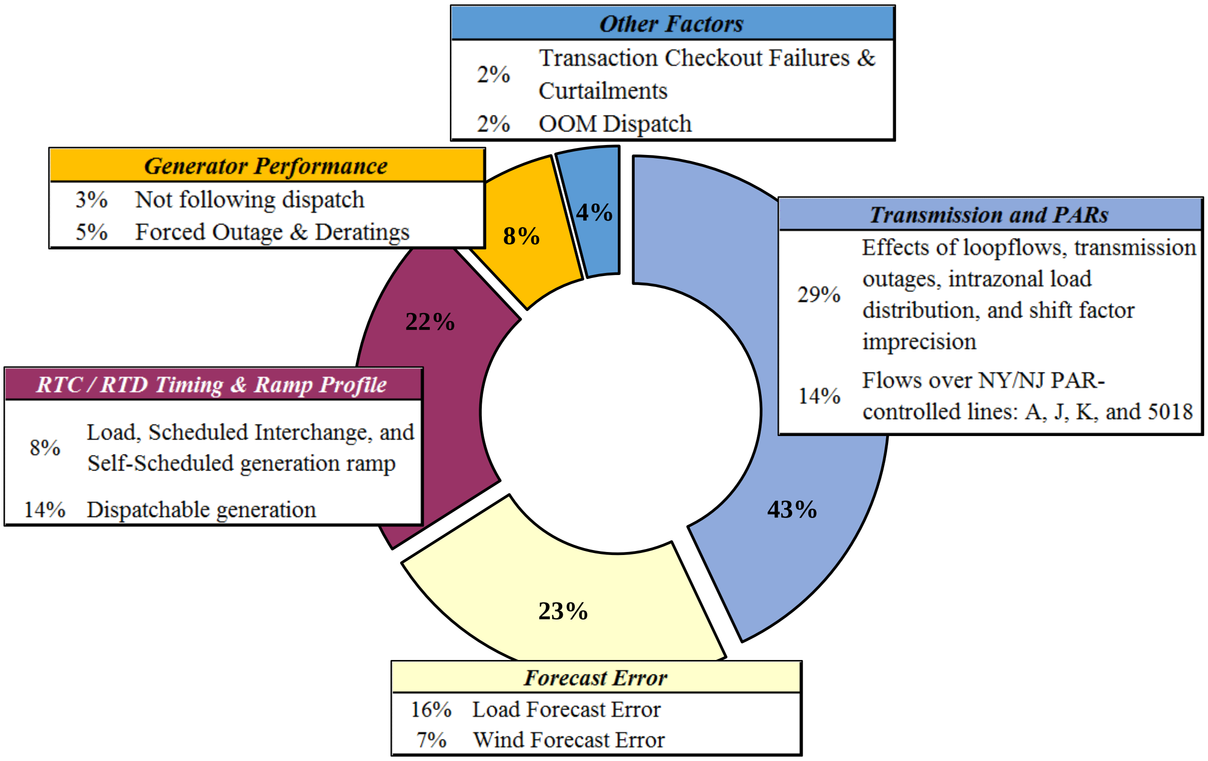
66 See Section IV.D in the Appendix for a detailed description of this metric (illustrated with examples).

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

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

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.

Figure 12: Detrimental Factors Causing Divergence Between RTC and RTD
2020



Second, errors in load forecasting and wind forecasting were another large contributor to price differences between RTC and RTD. This accounted for 23 percent of the overall divergence between RTC and RTD in 2020.[69] The contribution of the load forecast error rose from prior years, reflecting generally higher load forecast errors in 2020 likely because of the impact from the Covid-19 pandemic.

Third, the next largest category, which accounted for 22 percent of the divergence between RTC and RTD prices in 2020, 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,

69 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.

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).[70]

We have 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,[71] 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 XII.

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 renewable generation.

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70 Figure A-76 in the Appendix illustrates the ramp profiles that are assumed by RTC and RTD for external transactions.

71 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 PERFORMANCE

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 of the report discusses the following:

- A summary of capacity market results in 2020 in Section A;
- Principles for compensating resources efficiently in the capacity market in Section B;
- Issues with the existing capacity market design in Section C;
- Our recommended approaches to improving the capacity market in several areas:
  - Location-based marginal cost pricing of capacity ("C-LMP") in Section D;
  - Improvements to the capacity accreditation rules for each resource in Section E;
  - Efficient capacity compensation for transmission investments in Section F;
  - Quantifying the capacity benefits of transmission projects in the planning processes in Section G;
  - Enhancements to better reflect seasonal variations and the estimated net cost of new entry when setting the capacity demand curves in Section H.

A. Capacity Market Results in 2020

The Capacity Demand Curves determine how variations in the cleared supply of capacity affect clearing prices. Table 12 shows average spot auction prices for each locality for the 2020/21 Capability Year and year-over-year changes in key factors from the prior Capability Year.

Capacity prices rose sharply in New York City and systemwide, rose modestly in Long Island, but fell significantly in the G-J Locality. Changes to the Installed Reserve Margin ("IRM") and Locational Capacity Requirements ("LCRs") were a key driver of capacity prices variations.

- The Rest of State spot prices rose 137 percent, primarily because of a 1.9 percent increase in the IRM. A significant amount of capacity retired (including Indian Point Unit 2 and the Kintigh coal-fired unit), which was partially offset by new entry (e.g. from Cricket Valley Energy Center), increased imports (320 MW), peak load, and EFORd changes.

- In the G-J Locality, spot prices fell 35 percent, largely because of the 2.3 percent reduction in the LCR. The G-J Locality price was set by the systemwide curve throughout the 2020/21 Capability Year.
- In New York City, spot prices rose by 59 percent. The primary driver of this was the large year-over-year increase in the LCR of 3.8 percentage points.
- In Long Island, spot prices rose 5 percent. A lower demand curve Reference Point, decreased sales from local resources (37 MW in the summer), and uncleared capacity in the Rest-of-State area contributed to the increase in prices.

Table 12: Capacity Spot Prices and Key Drivers by Capacity Zone[72]
2020/21 Capability Year

	NYCA	G-J Locality	NYC	LI
UCAP Margin (Summer)				
2020 Margin (% of Requirement)	9.3%	15.0%	4.0%	12.8%
Net Change from Previous Yr	-1.2%	4.1%	-3.5%	0.8%
Average Spot Price (Full Year)				
2020/21 Price ($/kW-month)	$1.61	$1.61	$13.70	$3.03
Percent Change Yr-Yr	137%	-35%	59%	5%
Change in Demand				
Load Forecast (MW)	-87	-150	-130	-13
IRM/LCR	1.9%	-2.3%	3.8%	-0.7%
ICAP Requirement (MW)	512	-501	329	-50
Change in UCAP Supply (Summer)				
Generation & UDR (MW)	20	203	79	-35
SCR (MW)	-51	-29	-11	-2
Import Capacity (MW)	321			
Change in Demand Curves (Summer)				
ICAP Reference Price Change Yr-Yr	8%	7%	6%	-5%
Net Change in Derating Factor Yr-Yr	-0.5%	-1.0%	-0.6%	0.4%
Zonal EFORd Change Yr-Yr	-0.9%	-1.3%	-0.9%	0.3%

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.

B. Principles for Efficient Pricing in the Capacity Market

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 necessary to satisfy the "one day in ten year" planning

[72] See Section VI.D and VI.E in the Appendix for more details.

reliability standard. In this subsection, we evaluate the efficiency of LCRs that the NYISO determined for the upcoming 2021/22 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.[73]
- 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.

In an efficient market, 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, cost savings would result from shifting purchases from the high-cost zone to the low-cost zone.

The NYISO recently implemented the "Optimized LCRs" Method, which was first applied in the 2019/2020 Capability Year. It seeks to minimize capacity procurement costs given: (a) a long-term equilibrium at an LOLE of 0.1 days per year, (b) the NYSRC-determined IRM requirement, and (c) 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 and it tends to produce more erratic results. Minimizing *investment costs* is efficient because it selects the lowest cost resources to satisfy load and ancillary services requirements. This is comparable to minimizing production costs in the real-time market.

Table 13 shows the estimated MRI and CRI for each load zone based on the 2021/22 Final LCR Case.[74] Note, while the Commission's order on the proposed capacity demand curves for 2021/22 required the NYISO to make several modifications, the NYISO used the originally-filed demand curves when it determined the LCRs. Thus, the table shows the Net CONE values based on the originally-filed demand curves. The table also provides the capacity locality and the subregion for each load zone.

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73 The MRI is very similar to the marginal Electric Load Carrying Capability ("ELCC"). These two approaches are compared in Appendix Section VI.I.

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

Table 13: Marginal Reliability Impact and Cost of Reliability Improvement by Locality
2021/22 Capability Year

Locality/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*
NYCA					
A	$82		0.048	0.0047	$1.7
B	$82		0.048	0.0050	$1.6
C	$82		0.050	0.0030	$2.7
D	$82		0.050	0.0030	$2.7
E	$82		0.050	0.0029	$2.8
F	$82		0.050	0.0030	$2.7
G-J Locality		0.053			
G	$115		0.049	0.0037	$3.1
H	$115		0.049	0.0039	$2.9
I	$115		0.049	0.0039	$2.9
NYC					
J	$163		0.046	0.0067	$2.4
Long Island					
K	$106		0.049	0.0038	$2.8

The use of the Optimized LCRs Method in setting the LCRs has reduced the range in CRI values across load zones compared to years when the Tan 45 method was used to determine the LCRs. However, the table shows:

- The range between the minimum CRI-value location of Zone B (at $1.6 million per 0.001 events) and the maximum CRI-value location of Zone G (at $3.1 million per 0.001 events) is still significant.
- The wide variation in CRI values highlights that some areas have inefficiently high or low capacity requirements. For example:
  - The relatively low CRI in Zone J indicates that it would be efficient to place additional capacity there.
  - This highlights that the LCR for the 2021/22 Capability Year for Zone J (of 80.3 percent) is below the efficient level.

The CRI values for some zones exhibit considerable differences from those of other zones within the same capacity pricing region under the current configuration. This highlights transmission constraints within certain capacity regions that imply that the region should be broken into multiple regions to ensure that capacity is priced efficiently. For the 2021/22 Capability Year:

- A&B Pocket – Zones A and B are in a subregion that has a lower CRI than zones C to F, although resources in all of these zones receive the same capacity price. This reflects transmission constraints between zones B and C that were not binding in previous years. The emergence of the constraint is driven primarily by the Kintigh coal unit retirement in Zone A and the modeling of energy limitations for certain resources in GE-MARS.

- H&I Pocket – Zone G has a higher CRI than zones H and I even though UCAP resources in these areas receive the same price currently. The retirement of Indian Point units in Zone H has led to a reduction in the MRI of Zone G relative to zones H and I, indicating that it caused the constraints between zones G and H to bind. This impact was mitigated by planned changes to the operation of transmission facilities by Con Edison, which will increase the transfer limit between zones G and H. However, the relative MRI in Zone G could decrease further when Con Edison reverts to historical operation of these facilities in the summer of 2023.

A more detailed discussion of these results is provided in Appendix Section VI.G. The remainder of this section applies the MRI and CRI concepts to evaluate the capacity market (Section C) and support recommendations in five areas (Sections D to H).

C. Issues with Current Capacity Market

As discussed in Subsection B, an efficient capacity market should produce prices that are aligned with the reliability value of capacity in each locality. The current framework for determining capacity prices involves: a) estimating Net CONE and creating a demand curve for each existing locality, b) determining the optimal amounts of capacity to be procured in each locality at the LOE using the LCR Optimizer, and c) 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. In this subsection, we identify several aspects of the current framework that can lead to inefficient capacity market outcomes:

<u>Inadequate Locational Signals</u> – Efficient locational capacity prices require capacity zones that accurately recognize the systems' ability to access generation in different areas. Unfortunately, the rules for creating new capacity zones do not allow them to be created in a timely manner. This delay leads to prices that do not reflect critical resource adequacy needs in some areas and unexpected changes in the requirements in other areas. Current issues include the following:

- The lack of an A&B zone in the capacity market (which is discussed in Section B) compels the Tan45 process and LCR Optimizer to raise the IRM because they cannot procure needed capacity specifically in Zones A and B.[75]
- In addition to raising the IRM, this issue also caused the LCR Optimizer to produce unexpectedly low LCRs for New York City and Long Island in 2021/22.
- The lack of more granular locational capacity requirements increases the deliverability limitations and associated upgrade costs in the interconnection process, which can act as a barrier to efficient new investment.

<u>LCR Optimizer Uses a Flawed Objective Function</u> – The LCR Optimizer is designed to minimize consumer costs (i.e., procurement costs), rather than investment costs (i.e., marginal

75 The methodology places most additional resources in Zones C and D, shifting a small portion to Zone A.

production costs for capacity). This is incompatible with economic market design, and is fundamentally inconsistent with the objective in every other NYISO market to minimize production costs. In addition to the predictable inefficiencies this causes, it also:

- Produces volatile requirements because of the shape of the consumer cost curve; and
- Shift capacity requirements away from larger areas (i.e., New York City and Rest of State) toward smaller ones (i.e., Long Island and Zones GHI).

LCRs will be Affected by Any Errors Estimating Net CONE – Under the NYISO's Optimized LCRs method, the LCRs depend directly on the Net CONE estimate for each zone. Although we do not identify errors in the Net CONE estimates in this report, the process is inherently vulnerable to such errors, which can lead to an inefficient allocation of capacity across zones. Over-estimates of Net CONE will tend to reduce the LCR of the associated area, while under-estimates of Net CONE will tend to inflate the LCR of the area.

Inappropriate Derating Factor Applied to Net CONE Curves – The Net CONE is based on a hypothetical peaking unit, but the LCR Optimizer applies regional derating factors that are higher than the derating factor of the peaking unit. This tends to inappropriately reduce the LCRs in areas with high intermittent penetration and forced outage rates. Hence, this will create larger distortions as the penetration of intermittent generation increases in the future.

Some Resource Types Are Under or Over-Compensated – Non-conventional technologies (e.g. battery storage and intermittent resources) are valued based 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 marginal reliability value. Likewise, conventional generators with limited availability are also not valued appropriately. These accreditation issues are discussed in detail in Section E.

Costs Are Not Allocated to Beneficiaries – The NYISO currently allocates capacity costs based on where the capacity is located rather than to the load customers that benefit from the capacity.

Capacity Imports Are Not Scheduled or Priced Efficiently – 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 valuation of imported and exported capacity is inconsistent with the valuation of internal capacity.

Capacity Value of Transmission Is Not Compensated – New transmission frequently provides substantial resource adequacy value. However, the NYISO does not compensate new merchant internal transmission (such as an Internal UDR) for its capacity value. The NYISO also does not adequately consider this value in its economic and public policy transmission processes.

Misalignment with Demand Curve Reset – The NYISO currently sets the LCRs by minimizing the total procurement cost of capacity assuming the system is "at criteria" (i.e., an LOLE of 0.10). However, the demand curve reset is designed to attract a modest capacity surplus.

Poor Alignment between the Tan45 and LCR Optimizer – The LCR Optimizer employs minimum capacity floors needed to meet local transmission security criteria, but these minimum requirements are not modeled when the Tan45 is used by the NYSRC to determine the IRM. This can cause substantial shifts if the LCRs when transmission security criteria result in much higher capacity requirements in a zone than was assumed in the Tan45 process.

The remaining sections discuss our recommended approaches to improving the capacity market:

- Section D discusses location-based marginal cost pricing of capacity ("C-LMP").
- Section E proposes improvements to the capacity accreditation rules for each resource.
- Section F recommends efficient capacity compensation for transmission investments.
- Section G discusses how to quantify capacity benefits of transmission projects and make other improvements in the planning processes.
- Section H proposes enhancements to better reflect seasonal variations and the estimated net cost of new entry when setting the capacity demand curves.

D. Optimal Locational Marginal Cost Pricing of Capacity Approach

As discussed in Subsection B, prices in an efficient capacity market should be aligned with the reliability value of capacity in each locality. Given the array of concerns with the existing market, including the concerns about LCR Optimizer and limitations in creating new Capacity Zones, it may not be advisable for the NYISO to attempt to address all of these concerns. Hence, we propose an alternative approach to setting locational capacity prices and discuss how our approach would address concerns with the existing framework. Our approach 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.

We recommend the NYISO adopt our proposed C-LMP Framework, which would involve: [76]

- Replacing all existing capacity zones with pricing areas throughout the State and for each external interface that are consistent with the MARS topology;

[76] The MMU made of presentations to the ICAP Working Group in early 2020 on the design, implementation, and preliminary simulation results based on the 2019/2020 LCR Case and 2019 demand curves, which we summarize in this section. See ICAPWG presentations dated Feb. 6, Feb. 19, and Mar. 10, 2020.

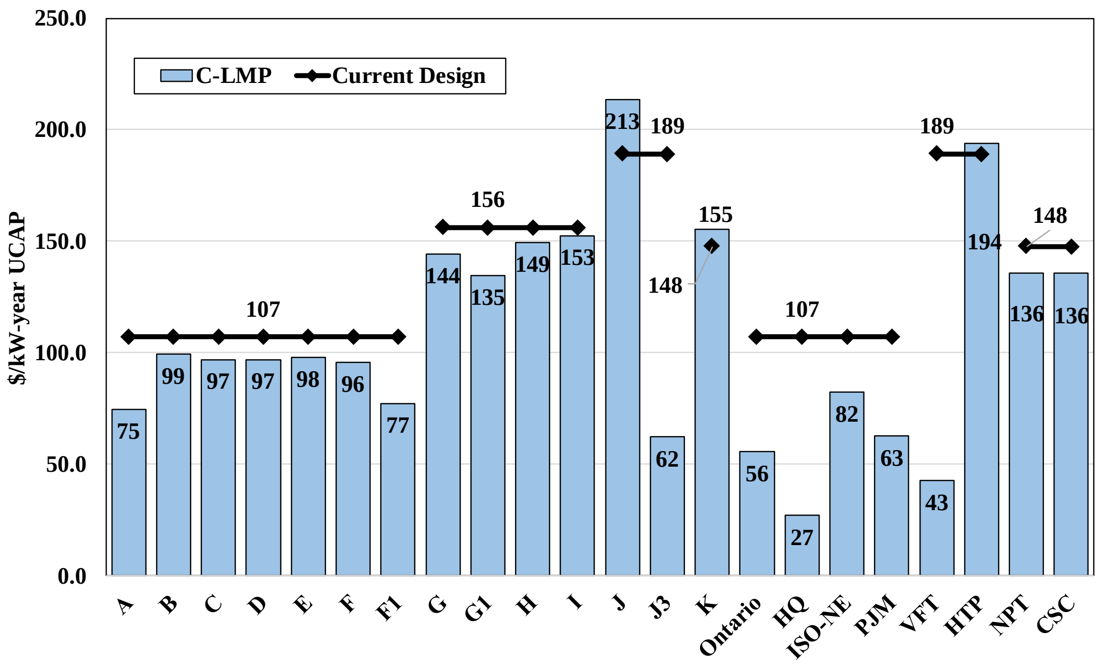
- Clearing the capacity market with an auction engine that is based on the resource adequacy model and constraints identified in the planning process; and
- Set locational capacity prices that reflect the marginal capacity value in each area.

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.[77] 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 13 illustrates the value of the C-LMP approach by comparing the estimated capacity prices under the C-LMP framework and current pricing at LOE conditions at internal locations, external interfaces and UDRs.[78] 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.

Figure 13: Capacity Prices at the Level of Excess for C-LMP vs. Existing Framework

Based on 2019 Final LCR MARS Case



77 See Recommendation #2013-1c in Section XII.

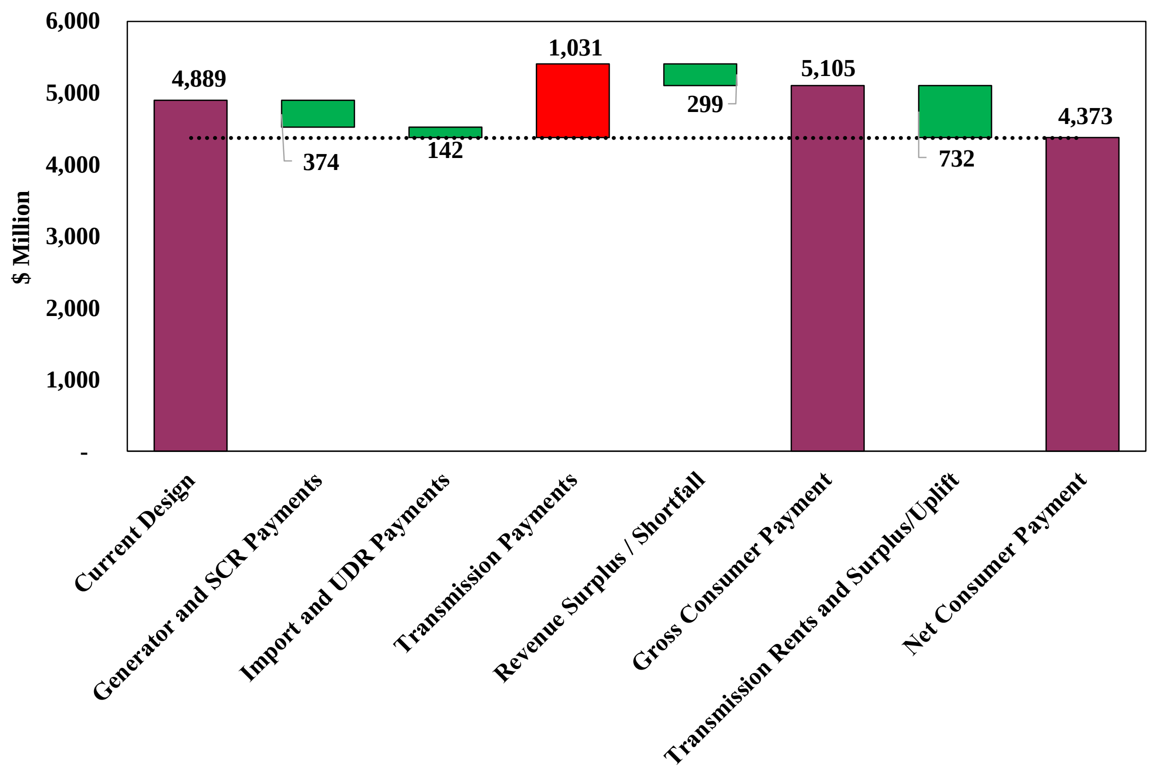
78 Capacity prices under the C-LMP approach are calculated based on MRI estimates reflecting the 2019/2020 MARS transmission topology and a CRI* of $2.65 million per 0.001 change in LOLE. The capacity price for zone z is then calculated as the product of CRI* and MRIz. Status quo capacity prices at LOE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

The capacity price in each area under the C-LMP approach is more aligned with the marginal reliability value of additional capacity in that area. These results highlight the misalignment between prices and value in several locations under the current framework. In particular:

- Resources in the Staten Island area are vastly over-priced.
- Resources in Zone A also appear to be over-compensated under the existing framework.
- The prices in Zones A and G-I may decline, while Zone K prices may increase under the C-LMP approach.
- Estimated prices for imports are lower under the C-LMP framework, which reflects the lower reliability value of externally located capacity compared to internal resources.

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 allow the creation of capacity-equivalent of TCCs (i.e. FCTRs), and (c) allow for a more equitable allocation of capacity costs, which are currently allocated to the area where the capacity is located rather than the area that benefits from the capacity. Figure 14 shows the change in estimated consumer payments between the current framework and C-LMP framework at 2019/2020 LOE conditions.[79]

Figure 14: Consumer Payments at Level of Excess for C-LMP vs. Existing Framework
Based on 2019 Final LCR MARS Case



79 For additional detail on the assumptions employed for this analysis, see *Locational Marginal Pricing of Capacity – Implementation Issues and Market Impacts* presented to the ICAPWG 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. In addition, 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.[80,81]

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, eliminating the need to modify Capacity Zones.
- Any bias in the estimation of Net CONE will not bias the distribution of capacity across different areas 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).

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. Improving the Capacity Accreditation of Individual Resources

We recommend that the NYISO revise its capacity accreditation rules to compensate resources in accordance with their marginal reliability value (Recommendation #2020-3). The marginal reliability value of individual resources should vary according to their availability during certain critical hours when capacity margins are tightest. Determining this value requires a thorough assessment of how all resources interact and affect critical hours.

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

81 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.

The following limitations of NYISO's current method for capacity accreditation have become apparent:

- The reliability value of intermittent and duration-limited resources changes as their penetration grows and impacts the timing and duration of critical hours. For example, a recent study commissioned by the NYDPS estimated that the capacity value of solar and offshore wind would decline to 9 percent and 12 percent of nameplate, respectively, by 2030.[82]
- Generators with long startup lead times and low capacity factors provide less reliability value than they are currently compensated for. These resources are less likely than other resources to be available during critical hours. Accurately discounting their UCAP value would encourage older, inflexible units to retire.[83]
- Individual large generating units are less effective from a reliability standpoint than multiple smaller units with equivalent capacity. This is because additional capacity is needed to secure against a contingency involving the loss of a single large unit. Accurately discounting the UCAP value of large-contingency units would encourage certain existing capacity (such as large steam turbine units) to retire.[84]
- Demand response resources that sell capacity through the Special Case Resource ("SCR") program are treated as providing significantly more capacity value in the ICAP market than in NYISO reliability planning studies. Determining the UCAP value of these resources based on their impact on system reliability would be more efficient and would encourage some resources to re-register as DERs with higher capacity value.[85]
- Generators that depend on pipeline gas with no back-up fuel may become less available during critical operating periods as the New York power system shifts from being a summer peaking to winter peaking system.

Hence, NYISO's current methods to convert resources' ICAP to UCAP rely on simple heuristics that do not accurately reflect the marginal impact on reliability of certain resource types. As a result, the UCAP rating of some existing resources is overvalued. Since the capacity planning requirements are based on models that do not consider the reduced availability of long lead time units, it results in the appearance of surplus capacity which reduces incentives for new investment when it is needed and leads to the retention of older units that provide little or no value. Current accreditation methods will become more outdated and inaccurate as the entry of intermittent and duration-limited resources makes reliability planning more complex.

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82 See Siemens, *Zero-Emission Electric Grid in New York by 2040* at p. 12, presented at November 23, 2020 Technical Conference in NYDPS proceeding 20-E-0197. Available on NYSDPS website in file "20-E-0197 Cover Letter and Slides 11242020 REVISED.pdf".

83 We discuss how the NYISO's current method to calculate EFORd (and therefore, resource UCAP) tends to overestimate reliability of units with long run times, such as steam turbine units, in Appendix VI.C.

84 See *MMU Comments on 2020 Reliability Needs Assessment*, October 20, 2020, at p. 5 and p. 8-9.

85 See *MMU Comments on 2020 Reliability Needs Assessment*, October 20, 2020, at p. 5 and p. 9.

Proposed Capacity Accreditation Method

Efficient capacity accreditation would accurately signal the marginal reliability value of each resource and improve incentives to invest in resources that best help to meet the reliability needs of a changing system. In the simplest terms, this value is determined by the expectation that the capacity of a resource will be available to maintain the reliability of the system under the tightest conditions when reliability is threatened. Our proposed means of estimated this value would consist of three components:

- *ICAP MW* – The MW of installed capacity of the individual resource,
- *Critical Period Availability Factor* – This factor accounts for the tendency for some types of resources to be less available during critical periods when resource adequacy deficiencies are most likely to occur.
- *Individual Performance Factor* – This is a discount that would account for the individual performance of the resource compared to other units of the same type.

The calculation of the payment would be as follows:

$$\text{Payment}_i = \{\text{ICAPMW}_i\} \times \{\text{Individual Performance Factor}_i\} \times \{\text{Critical Period Availability Factor}_{T,L,i}\}$$

Section VI.I of the Appendix provides additional details about how the Individual Performance Factor and the Critical Period Availability Factor would be calculated for each type of resource.

F. 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. Transmission often provides significant resource adequacy benefits, which can be estimated using the MRI-techniques that are described in the C-LMP proposal. To provide efficient incentives to invest in transmission, we recommend that transmission developers receive financial capacity transfer rights ("FCTRs") for upgrades where the compensation for the CFTR is based on the MRI of the facility.[86] The Appendix of this report analyzes how FCTRs might affect a transmission investment decision.[87]

As intermittent generation is added to the grid, there will be additional opportunities for investment in transmission to deliver the output to consumers. However, 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

86 See Recommendation #2012-1c in Section XII.

87 See Appendix Section VI.G for additional details.

transmission. Thus, it is unlikely that efficient market-based investments in transmission will occur if transmission developers cannot receive capacity market compensation.

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

G. Reforms to the Economic and Public Policy Transmission Planning Processes

Integrating large amounts of renewable generation in the coming years will drive the need for transmission investments. It is important that NYISO's economic and public policy transmission planning processes accurately evaluate project benefits so that the most cost-effective projects move forward. Significant changes to these processes' assumptions and procedures are needed to ensure that they are effective.

The NYISO has an Economic Planning Process, which is intended to provide cost-of-service compensation through the NYISO tariff when a project is expected to be economic based on a benefit-cost analysis.[88] However, since being established in 2008, no transmission has ever been built through this process. NYISO has also evaluated solutions for two Public Policy Transmission Needs ("PPTN"): the Western New York PPTN and the AC Transmission PPTN.[89] In March 2021, the NYISO was ordered by the NYPSC to consider solutions to a Public Policy Requirement for transmission to deliver offshore wind energy.[90] The use of the PPTN assessment process to address congestion in western New York (where congestion was driven by existing resources rather than future entry of renewables) highlights deficiencies in the Economic Planning Process.

In this subsection, we discuss some of the shortcomings of the Economic Planning Processes and summarize our recommended enhancements. Our reports evaluating proposed PPTN projects

88 This process has historically been known as the Congestion Assessment and Resource Integration Study ("CARIS"). NYISO has filed tariff changes in early 2021 that would rename the initial CARIS Phase 1 study of system congestion to the "System & Resource Outlook" and rename the CARIS Phase 2 evaluation of proposed transmission projects to the "Economic Transmission Project Evaluation (ETPE)". For clarity, we refer to the process here as the Economic Planning Process.

89 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.

90 See NYPSC Case 20-E-0497.

have also identified a number of areas for potential improvement in that process. Key areas for improvement to the economic planning and public policy processes include the following:

- Capacity Benefits – The Economic Planning Process significantly undervalues some projects because its benefit-cost ratio does not include capacity market benefits. Transmission projects can provide value by reducing the amount of generation capacity that is needed to meet planning requirements, and considering these benefits would reduce the project's revenue requirement.[91] Hence, we recommend including capacity market benefits in the benefit-cost ratio when evaluating economic projects.
- Amortization Period – The Economic Planning Process evaluates proposed projects using a 10-year discount period for its benefit-cost analysis. This discount period is too short to realistically approve economic transmission projects, which have much longer useful lives. We recommend using a 20-year discount period when evaluating economic projects.
- Assumed Entry and Exit – Resource inclusion rules used in project evaluations are overly restrictive and effectively exclude projects that are likely to drive congestion, such as contracted policy-driven resources. We recommend developing criteria to identify resources likely to enter in the near-to-mid term (e.g. 5-7 year horizon), which can reasonably be included when evaluating projects. Such criteria should balance the risk of including non-firm projects with the cost of using overly restrictive assumptions.
- Economic Entry and Exit – Long-term modeling of the resource mix in both processes does not rely on economic criteria, and risks evaluating projects using unrealistic assumptions. The PPTN should model the mix of future resources needed to meet policy goals in an efficient manner that avoids arbitrary assumptions, and should account for how transmission projects might realistically shape the optimal mix of resources.[92] Both processes should model realistic entry and exit of conventional units (including how they would be affected by the transmission project), instead of assuming a static resource mix.
- Voting Requirement – Before an economic project is funded, the project must garner approval from 80 percent of the beneficiaries. While such a vote may be appropriate to ensure that only projects that are clearly economic move forward, the 80 percent requirement is unreasonably high. This supermajority requirement may enable a small group of participants to block an economic investment.

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91 For instance, our analysis in Section VI.H of the Appendix demonstrates that capacity benefits for a recent transmission project could be up to 80 percent of its revenue requirement under long-term equilibrium conditions.

92 For example, capacity expansion modeling approaches or similar tools might be employed so that the most efficient mix of new resources needed to meet policy goals given transmission limitations is modeled with and without the proposed transmission project in service.

Table 14 summarizes our recommended enhancements to the CARIS and PPTN evaluations, many of which would be applicable to both.[93]

NYISO filed tariff revisions in February 2021 that would make changes to aspects of the Economic Planning Process, focused on making the initial system assessment phase more flexible and informative.[94] We support these improvements, and encourage NYISO to pursue improvements to the project evaluation stage that would make it possible for economic transmission projects to be approved.

Table 14: Recommended Improvements to Economic & Public Policy Planning Processes

Recommendation	Economic	PPTN
Assumptions Impacting Project Valuation		
Quantify capacity market benefits of transmission projects in benefit-cost ratio.	✓	✓
Use a 20-year discount period for transmission project benefit-cost analysis.	✓	
Model entry and exit decisions for conventional generators in a manner that is consistent with the expected competitive market outcomes.	✓	✓
Expand inclusion rules when evaluating projects to model a broader set of likely new entrants, including Public Policy resources.	✓	
Model entry and exit of resources to meet public policy goals based on economically efficient criteria.		✓
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 Economic Planning 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 Economic Planning to facilitate optimal project sizing.	✓	

93 For details of recommendations for the PPTN process, see March 22, 2021 comments of Potomac Economics in NYPSC Case 20-E-0197, 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*.

94 See NYISO presentations on *Economic Planning Process Improvement* to Electric System Planning Working Group (ESPWG) and FERC Docket ER21-1074.

We recommend that the NYISO review the Economic Planning Process to identify any additional changes that would be valuable and make the changes necessary to ensure that it will identify and fund economic transmission projects.[95] 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.[96]

H. Other Proposed 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. In each capability period, the ICAP 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. Hence, we recommend the NYISO set monthly capacity demand curves by allocating the demand curve unit's annual revenue requirement based on the marginal reliability value of capacity in each month.[97]

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).[98] 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). Furthermore, if gas-to-electric switching and other electrification efforts cause New York to transition from a summer-peaking system to a winter-peaking system, this recommendation would help ensure that capacity market incentives are focused during peak demand conditions.

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95 See Recommendation #2015-7 in Section XII.

96 See March 22, 2021 comments of Potomac Economics in NYPSC Case 20-E-0197 and January 22, 2019 comments of Potomac Economics in NYPSC Case 18-E-0623.

97 See Recommendation #2019-4 in Section XII.

98 See Section VI.F of the Appendix for more detailed analysis.

Translation of Demand Curve Reference Point from ICAP to UCAP Terms

The capacity demand curves are currently set artificially high due to the use of incorrect derating factors, leading to inefficiently high consumer payments. Correcting this issue is a low-effort project requiring changes to a small number of parameters used to determine the demand curves.

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 (or ICAP-UCAP ratios) of all existing resources. The demand curve unit, as a new plant, typically has a lower forced outage rate relative to the average derating factor. The use of a higher derating factor results in higher UCAP demand curves. Hence, the current method of translating the Net CONE using the average derating factor leads the monthly capacity demand curves to be set higher than if the demand curve technology's derating factor were used. As a result, the annual capacity revenue accrued to the demand curve unit at the Level-of-Excess conditions exceeds the annual revenue requirement (i.e. the net CONE) of the unit.

The use of an inappropriate ICAP to UCAP translation increased the zonal summer UCAP Reference Points used in the 2020/2021 Spot Auction by 1.4 percent to 6.7 percent. The largest percentage impact was in NYCA, where the summer zonal derating factor of 8.3 percent was much higher than the demand curve unit's EFORd of 2.2 percent. At demand curve conditions, this would have increased consumer payments by $166 million per year across all zones.

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.[99] Hence, we recommend the NYISO utilize the estimated forced outage rate of the demand curve unit technology to perform the ICAP to UCAP translation.[100]

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99 For example, in its Class Year 2019 Buyer-Side Mitigation Forecast, the NYISO estimated that the NYCA derating factor would increase to 13.7 percent by the Summer 2022 period due to the presence of over three GW of onshore wind and solar resources. See *Buyer Side Mitigation ICAP Forecast – Class Year 2019 Assumptions & References*, December 2020.

100 See Recommendation #2019-5 in Section XII.

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.[101] 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 and consumer costs.

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 developers 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. This is true even for renewable generators that participate in Index REC contracts, which expose the project to key elements of wholesale market risk.[102]
- *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—all attributes that wholesale markets can value efficiently—play key roles in determining whether a particular project will be profitable to a developer.

Figure 15 shows the estimated after-tax annual return on investment in several types of new generation. Annual returns are based on historical price data from 2018 to 2020 (using costs for

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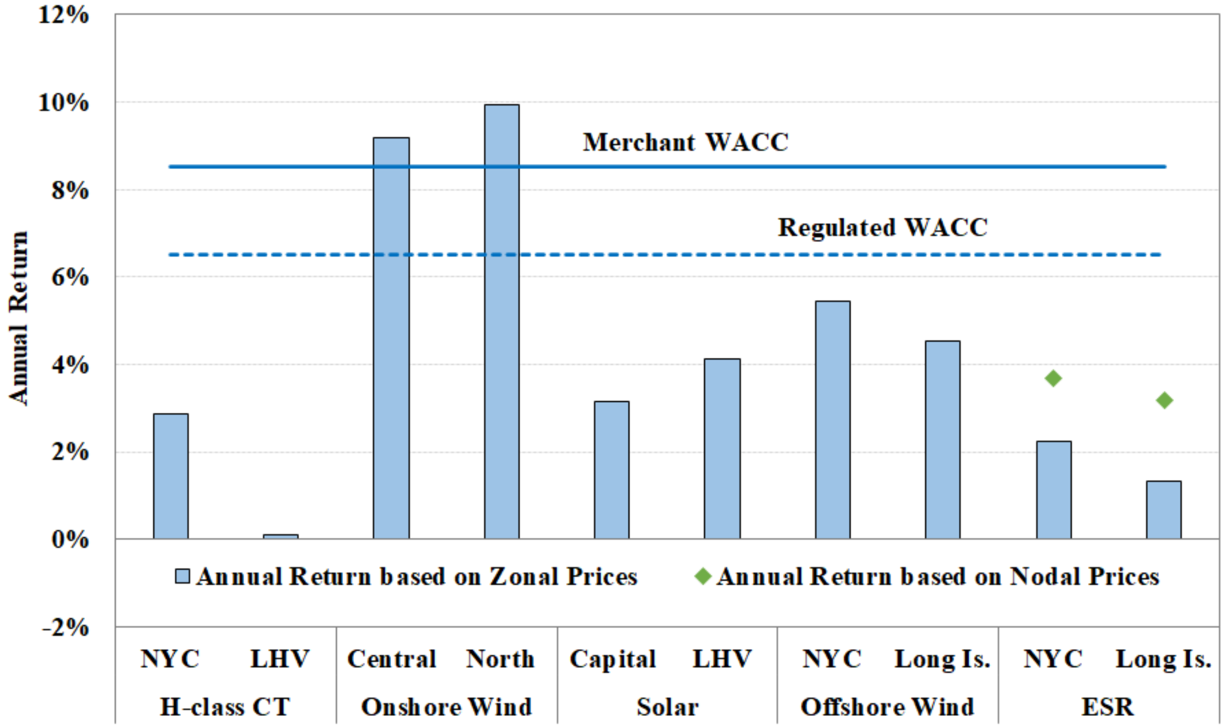
101 Net revenue is the total revenue that a generator would earn less its variable production costs. Investors seek to earn sufficient net revenue to recover the cost of their capital investments in generating units.

102 See subsection IX.A for a discussion of the risks faced by developers that enter into Index REC contracts.

entry in 2020), including energy and ancillary services revenues, capacity market revenues, and applicable incentives including renewable energy credits, ITC/PTC, and bulk storage incentives.[103] The figures compare the annual return for each project with the after-tax WACC for: (a) a merchant entrant, and (b) a regulated entity.[104] A project with a weighted average cost of capital below its estimated annual return would be profitable. For each technology and location, the bars show the annual return based on the zonal price and base cost assumptions. The green diamonds show how annual return at select individual locations downstream of transmission bottlenecks within the zone.[105]

Figure 15: After-Tax Annual Return of New Generation
2018 – 2020



Our analysis of the economics of generation investment indicates that there are significant differences by technology and zone, and there is substantial variation across zones, and even within zones. Based on 2018 to 2020 outcomes, the only technology that appears to be economic is onshore wind, with its returns being boosted by state and federal incentives. Investments in all other technologies and locations would earn well below even the regulated WACC. Given the

103 Details on estimated net revenues for each technology can be found in Appendix Sections VII.A and VII.C.

104 The merchant WACC value shown is based on assumptions from the latest demand curve reset study. 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.

105 Green diamonds show the Gowanus 138 kV (NYC) and Barrett 1 bus (Long Island) locations.

surplus capacity levels in most regions and the lack of investment in technologies other the onshore wind, this result is consistent with recent investment patterns. However, there will be opportunities for profitable investment in other technologies in the coming years because of the combination of falling costs and increased state and federal incentives.[106]

Discussion of Incentives for New Units by Technology Type

Gas-fired Combustion Turbines – The estimated annual return is well below the typical merchant WACC for the locations that we analyzed.[107] It is possible that projects with site-specific advantages would have higher returns, or that future developments – such as retirement of existing downstate capacity affected by NYDEC emissions regulations – could result in profitable opportunities for new peaking plants. However, 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.[108, 109]

Renewable units – At recent historical prices and costs, estimated annual returns are high enough to earn a merchant rate of return for land-based wind, but other renewable technologies would earn far below even a regulated rate of return. However, falling costs of solar and offshore wind projects suggest that these technologies will be profitable at many locations in the future.[110] In New York State, state and federal incentives account for the majority of net revenues (up to 76 percent) for all renewable projects evaluated.[111] These incentives are generally subject to lesser market risk (relative to NYISO market revenues), which may lower the returns required by investors to a value closer to the WACC of the regulated entity.

Energy storage – The estimated annual return for four-hour battery storage projects in 2018-2020 was lower than the regulated WACC even after inclusion of state incentives. However, it is projected to improve substantially in the coming years as the battery costs decline. Projects at high-value nodes may even earn returns approaching a merchant cost of capital within the next three years. Furthermore, there will likely be profitable opportunities to add energy storage on the site of existing generators (i.e., hybrid storage) in the next three years. Additionally,

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106 See subsection IX.A.

107 Costs and revenues for the CT reflect a 7HA.02 Frame unit, assumed to be at a brownfield site in NYC.

108 See link for Executive order No. 52, signed February 6, 2020.

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

110 See subsection IX.A.

111 State and federal incentives make up 65 percent of estimated revenues for solar PV, 72 to 76 percent for land-based wind, and 72 percent for offshore wind in 2020. See subsection 0.C of the Appendix.

revenues of storage projects may benefit in the future from price volatility caused by renewable generation and from recommended market design enhancements to the energy and ancillary services markets.[112] Hence, it is likely that merchant storage investment could be economic on an unsubsidized basis in the coming years.

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. 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

As the resource mix shifts away from conventional fossil-fuel generation, it is important to provide market incentives that lead to the retirement of the least valuable generators (rather than flexible resources that are more effective for integrating intermittent generation) and motivate investment in maintaining generation in a reliable condition. The following evaluation considers the current market incentives for several conventional technologies in New York.

Figure 16 shows the net revenues, and the estimated going-forward costs ("GFCs") (or average generation cost for nuclear units), for several existing technology types in the period 2019-2021.[113] 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.[114] 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

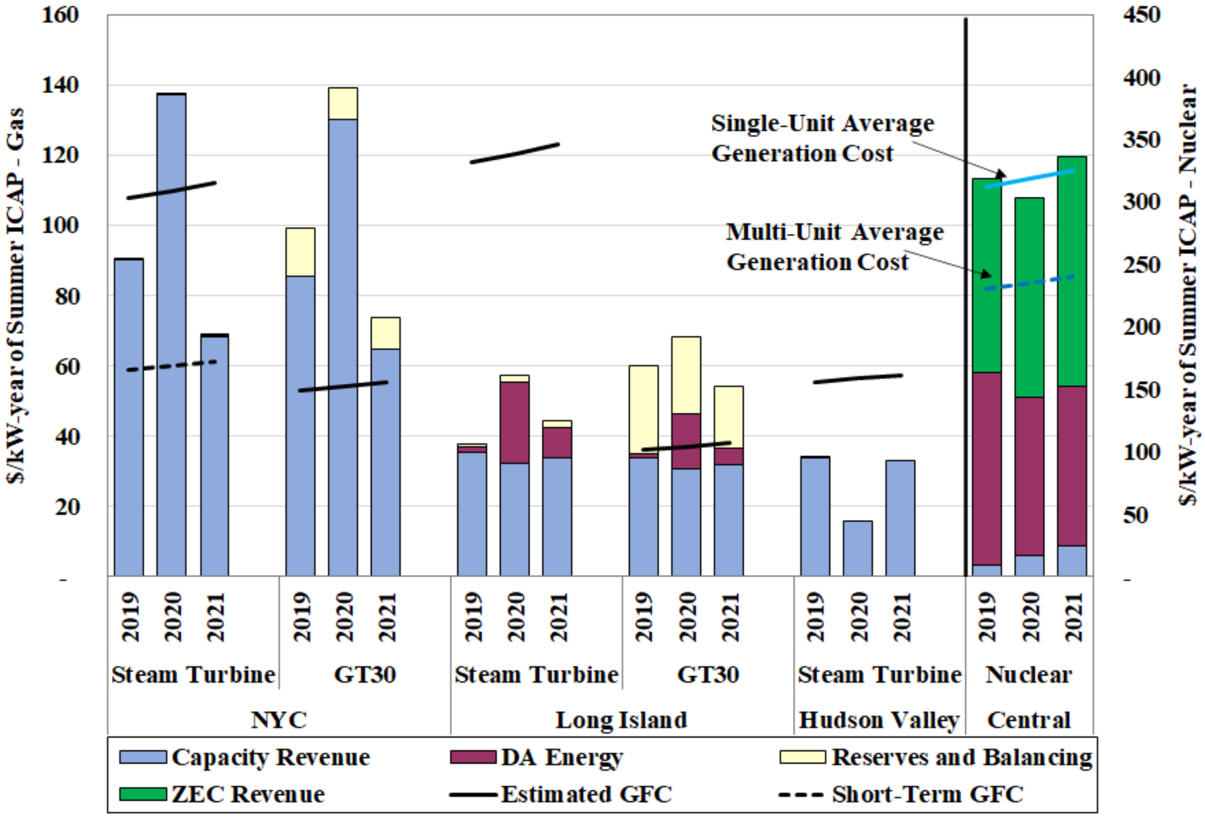
112 See subsection C and subsection IX.A.

113 Annualized average generation costs for US nuclear units are $312/kW-year for a single-unit facility and $231/kW-year for a multi-unit facility. The estimated average costs of nuclear plants are based on NEI/EUCG reports and presentations.

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

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.[115]

Figure 16: Net Revenues and Going-Forward Costs of Existing Units[116]
2019 – 2021



The net revenues of existing units New York City increased from 2019 to 2020 and are expected to decrease in 2021, due to fluctuations in capacity prices. 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 past few years have been lower than the estimated GFC in Long Island, New York City, and the Lower Hudson Valley. However, net revenues for a steam turbine in New York City were

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115 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.

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

above an estimated "Short-Term GFC", which assumes that its owner defers major maintenance and other expenses, although it is not possible for a resource owner to pursue this strategy indefinitely. In Long Island, steam turbine generators are compensated through a long-term contract that does not expire until 2023, so these units may have stronger incentives to perform maintenance. In Hudson Valley, steam turbine generators may have incentives to defer maintenance.

There is considerable uncertainty regarding 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.

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.[117] Approximately 750 MW (nameplate) of GT capacity in Zone J have indicated that they intend to retire in response to limits that would be enforced starting in May 2023. Additionally, plant owners have indicated that 350 MW of capacity will operate only during the non-ozone season (October through April) beginning in 2023 and that this will grow to over 1,000 MW in 2025.[118]

Nuclear Plants – Net revenues of existing nuclear plants in 2020 were above the US average generation costs for multiple-unit facilities and below the average generation costs for single-unit facilities.[119] Average net revenues over the 2019-2021 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 52 percent of average net revenues from 2019 to 2021. Hence, ZECs continue to be a critical for the operation of these units.

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117 See DEC's proposed rule *Ozone Season Oxides of NOx Emission Limits for Simple Cycle and Regenerative Combustion Turbines*. See link.

118 See NYISO 2020 Gold Book Table IV-6.

119 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.

C. Impacts of Energy & Ancillary Services Pricing Enhancements

Section XII 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. Furthermore, by compensating resources in a more targeted manner, these reforms tend to lower the overall costs incurred by consumers.

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 New York City, and
- the consumer cost impacts in New York City.

Specifically, we modeled the impact of four enhancements to real-time pricing:

- 2017-1: Model local reserve requirements in New York City load pockets.[120]
- 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.
- 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.

The first three enhancements are quantified separately, while the fourth enhancement is not. This is because setting operating reserve requirements dynamically would be coupled with each enhancement to make it work more efficiently.

Impact of Pricing Enhancements on Long-term Investment Incentives

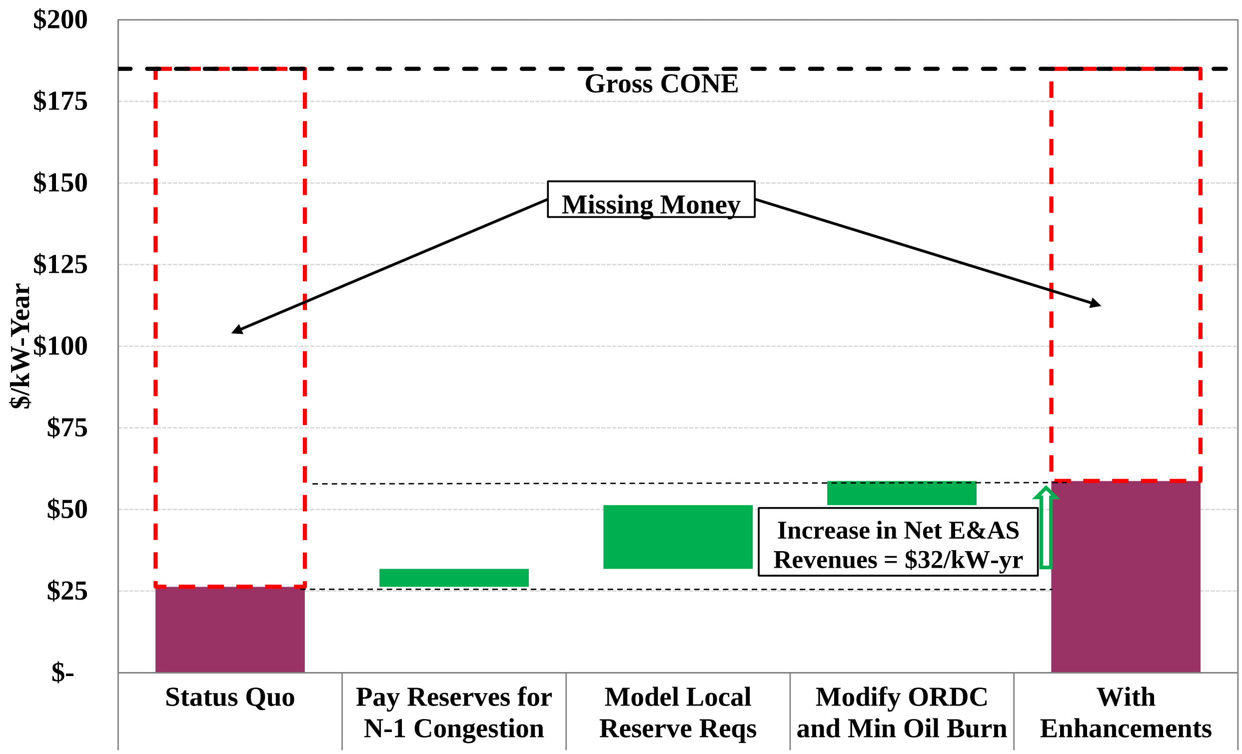
In an efficient market, higher energy and ancillary services net revenues reduce the "missing money" that is needed to attract sufficient investment to satisfy planning reliability criteria. In recent years, the capacity demand curve has been set based on the missing money for a new

120 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.

Frame unit.[121] Hence, market enhancements that efficiently move net revenues to the energy and ancillary services markets lead to reductions in the capacity demand curves.

Figure 17 shows 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.[122, 123] It also shows the increase in the H-class Frame unit's net revenues, which would result in an equivalent decrease in the Net CONE used for determining the ICAP Demand Curve for the zone.

Figure 17: Impact of Pricing Enhancements on Net Revenues of NYC 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 123 percent in New York City if the recommendations were implemented (based on current market conditions). Consequently, the Net CONE for the ICAP demand curve and the capacity payments to all resources would decline by 20 percent in New York City. 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.

121 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.

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

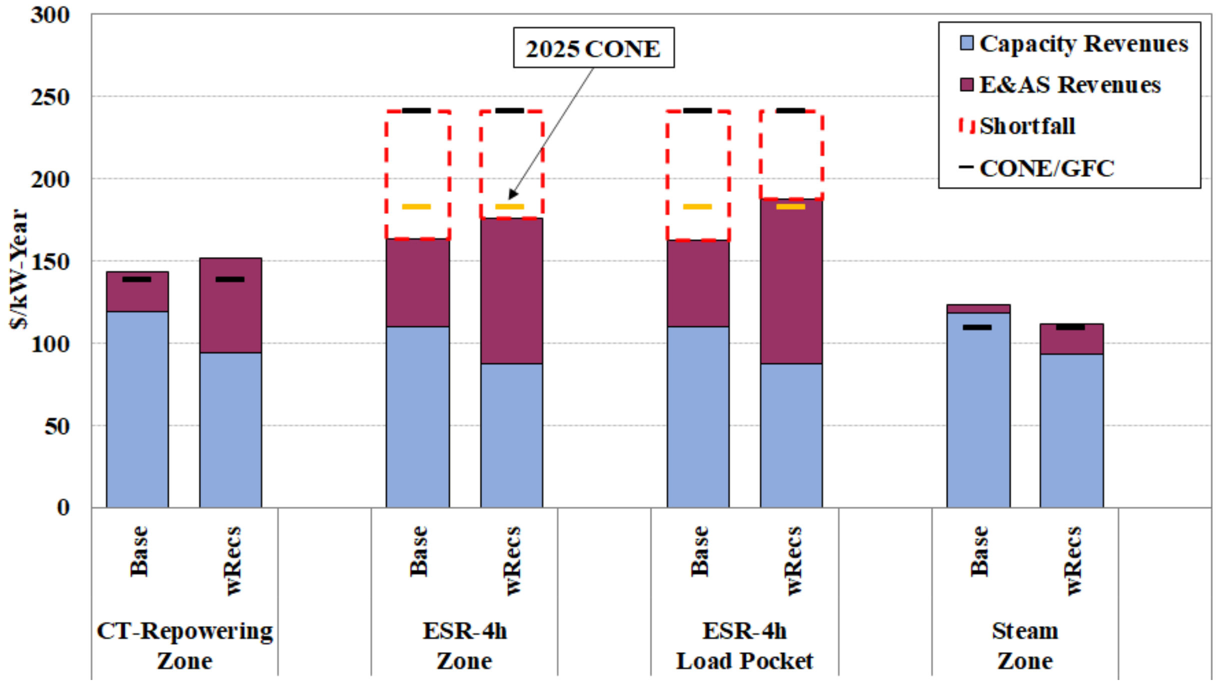
123 See Section XII for more details regarding these recommendations.

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 60 percent increase in the E&AS revenues. However, it is important to consider that the price effects of enhanced reserve pricing are likely grow as existing peaking units begin to retire or discontinue operation in the zone season starting in May 2023. 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.[124]

Figure 18 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. 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.[125] The "wRecs" category shows our estimates if the above recommendations were adopted.

Figure 18: Net Revenue Impact from Market Enhancements – New York City

At the Part A Threshold



124 Net revenue of the NYC demand curve unit were estimated to increase by $19/kW in 2025 if carbon pricing was implemented. See *MMU Evaluation of Impacts of Carbon Pricing*, May 9, 2019.

125 The NYISO proposed Tariff revisions to the Part A test in 2020 that would 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.

The recommended enhancements increase 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. 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.

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 three 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.

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.

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 IX, 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.

Impact of Pricing Enhancements on Consumer Costs

The proposed pricing enhancements would result in higher energy and reserve market costs to consumers, but would reduce other costs, particularly capacity procurement costs. Figure 19 shows the estimated impact that the proposed enhancements would have had on New York City consumer costs using price data from the period 2018 to 2020. The cost impacts we show in the figure are as follows:

Increase in Energy Payments – Includes higher energy prices due to modeling of load pocket reserve requirements (#2017-1) and higher shortage pricing values (#2017-2)

Increase in Reserve Payments – Includes higher reserve prices due to modeling of load pocket reserve requirements, higher shortage pricing values, and payments to reserve providers for congestion relief (#2016-1).

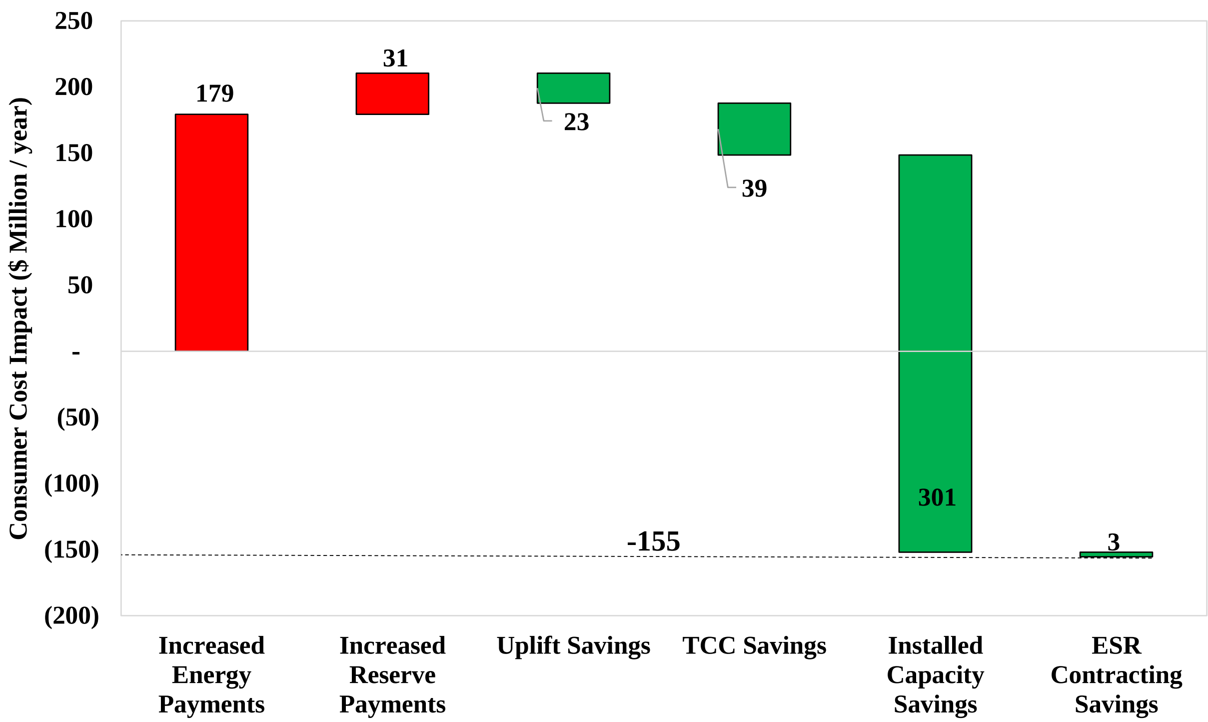
Decrease in Uplift Costs – Reduction or elimination of uplift payments due to the proposed modeling of local reserve requirements in NYC load pockets.

Transmission Congestion Contract Savings – Additional revenues to TCC holders due to the increase in New York City energy prices, which are assumed to be passed through to consumers.

Decrease in Installed Capacity Costs – Includes lower capacity prices due to a higher energy and ancillary services offset for the ICAP Demand Curve unit.

Decrease in Energy Storage Contact Costs – Reduction in the out-of-market contract payments to storage resources due to the increase in the NYISO market net revenues of energy storage resources in high-value load pockets of the Con Edison system.

Figure 19: Impact of Price Enhancements on Consumer Costs in New York City
At Level of Excess Conditions



We estimate that, under the long-term equilibrium conditions, our recommended enhancements could reduce annual consumer costs in New York City by an approximately $155 million.

Higher payments to energy and reserve providers would be offset mostly by savings in capacity payments, and to a lesser extent by savings in uplift costs, TCCs and energy storage contract payments.[126]

As discussed in the previous subsection, our proposed enhancements increase the revenues for the ICAP demand curve unit from the energy and ancillary services markets, resulting in a lower ICAP demand curve. Consequently, the capacity prices in New York City would decrease, thus reducing the costs associated with capacity payments to all resources. In contrast, although energy prices increase, the related consumer costs increase to a lesser extent because only a smaller group of resources (generally the more flexible resources) would benefit from these energy price increases.

Notwithstanding, the consumer cost savings are highly dependent on the size of the capacity surplus. When the market is at the long-term equilibrium modeled in the demand curve reset, adjustments in the capacity demand curves have large capacity price effects, but these price effects shrink as the capacity surplus grows. Therefore, it is likely that the net consumer savings modeled in the figure would drop close to $0 (and begin to move in the negative direction) if the capacity surplus in New York City rose above around 11 percent.

126 See subsection VII.D of the Appendix for the assumptions and methodology used for estimating impact on consumer costs.

IX. USING NYISO MARKETS TO ACHIEVE PUBLIC POLICY GOALS

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 the lowest possible cost. Market price signals could help shift investment towards: (a) renewable energy projects that are more effective in displacing fossil-fuel generation, and (b) flexible resources that are more effective in helping to integrate intermittent renewable generation. In particular, an efficient capacity market will become increasingly important to flexible and/or hybrid resources whose long-term profitability will depend in part on future capacity revenues.

In this section, we discuss the following:

- Importance of wholesale market incentives for achieving state policy goals in a cost-effective manner
- Risks for renewable developers with long-term contracts for Index RECs
- Role of BSM measures in reducing risk for investment in flexible resources
- Initiatives that would reduce conflict between state policies and BSM measures
- Impact of recommended enhancements on future development of clean resources

A. Importance of Market Incentives for Achieving State Public Policy Goals

Achieving state policies will require significant additions of intermittent renewable generation and flexible resources such as battery storage. The State established a 70 percent clean energy target by 2030, along with various resource-specific requirements. State and federal incentives account for a large portion of the compensation for these resources.[127] However, energy and capacity markets still provide critical price signals that differentiate resources based on their value to the power system, encouraging the most economic projects to come forward, and providing sustained revenues after state and federal incentives end.

As the generation mix evolves, the wholesale markets will play a key role in facilitating the development of the following resources that the state seeks to promote:

- *Energy storage* – As larger amounts of intermittent renewable generation are added to the system, ESRs will continue to have substantial capacity value, and they will benefit from increasing real-time energy price volatility and an expanding ancillary services market.
- *Renewable generation* – Wholesale market incentives guide investment towards projects that face less curtailment risk and are less-costly to integrate in the power system.

[127] State and federal incentives make up 65 percent of estimated revenues for solar PV, 72 to 76 percent for land-based wind, and 72 percent for offshore wind in 2020. See VII.C of the Appendix.

- *Hybrid storage* – As the capacity value of intermittent renewable generation falls and the risk of curtailment increases, developers will have strong incentives to add battery storage to existing plants to firm-up their generation.
- *Existing flexible generation* – Market incentives will help ensure that as older conventional generators retire, ones that are more flexible (and effective in helping integrate renewables) will remain in service longer than inflexible ones.

Indeed, the New York Public Service Commission has expressed a preference for Index REC contracts because "it is important to preserve the structural incentives for projects to maximize generation during peak pricing periods".[128] Index RECs contracts entitle the generator to receive a payment equal to:

Payment = {Strike_Price} minus {Monthly_Average_Zonal_DA_LBMP} minus {Monthly_Zonal_Capacity_Spot_Price · UCAP_Factor}

If the renewable generator sells output and capacity at prices equal to the monthly average prices in this formula, then the sum of the REC payment and wholesale market revenue will equal the strike price. However, if the generator tends to produce output when LBMPs are lower than average or the actual capacity value of the resource is lower than the UCAP Factor, then the total revenue received by the generator will be lower than the strike price of the Index REC. In this way, the Index REC structure is designed to encourage the development of renewable generation that provides greater value to the system. It also provides incentives for complementary investments that enable the generator to hedge risk such as by adding onsite battery storage.

Role of Market in Guiding Clean Energy Investment

NYISO markets play a key role in guiding policy-driven investment towards the most cost-effective technologies and locations. Using projections of prices and other market outcomes from NYISO's 2019 Congestion Assessment and Resource Integration Study (CARIS) 70x30 Case,[129] Figure 20 and Figure 21 evaluate how revenues earned would vary for three different renewable generation technologies across different locations in the State.

For each zone, Figure 20 shows:

- Zone Average Price – The simple average price for the zone where the project is located.
- LBW Average Price – The generation-weighted average price that a land-based wind ("LBW") project would receive at the zone where the project is located.
- PV Average Price – The generation-weighted average price that a solar photovoltaic ("PV") project would receive at the zone where the project is located.

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128 NYPSC, *Order Modifying Tier 1 Renewable Procurements*, January 16, 2020. Case 15-E-0302.

129 The 70x30 Case was developed to show one possible resource mix that satisfies state goals by 2030. For more detail on this analysis, see *NYISO MMU Review of the 2019 CARIS Phase 1 Study*, June 2020.

- OSW Average Price – The generation-weighted average price that a land-based wind ("OSW") project would receive at the zone where the project is located.

Figure 21 also provides this information for individual pricing nodes to illustrate how prices vary significantly within a particular zone.

These two figures highlight two concepts that are useful for comparing the returns of different projects that enter into Index REC contracts:

- Technology Discount – The first figure shows the difference between the Zone Average Price and generation-weighted average zonal price for a particular technology. This captures the difference between the zone average price and the price that the technology would earn in that zone.
- Nodal Discount – This is the difference between the generation-weighted average price that a particular technology would earn at a node versus at the zone level.

Figure 20 shows these quantities for five zones, while Figure 21 shows these quantities for 12 nodes across the five zones. As the penetration of intermittent renewables increases, large differences in value tend to emerge for generation of different locations and technologies. High saturation of one resource type (such as solar PV in the case shown) would tend to result in a large technology discount and/or nodal discount.

Figure 20: Renewable Technology Discounts in CARIS 70x30 Case

For 5 Zones

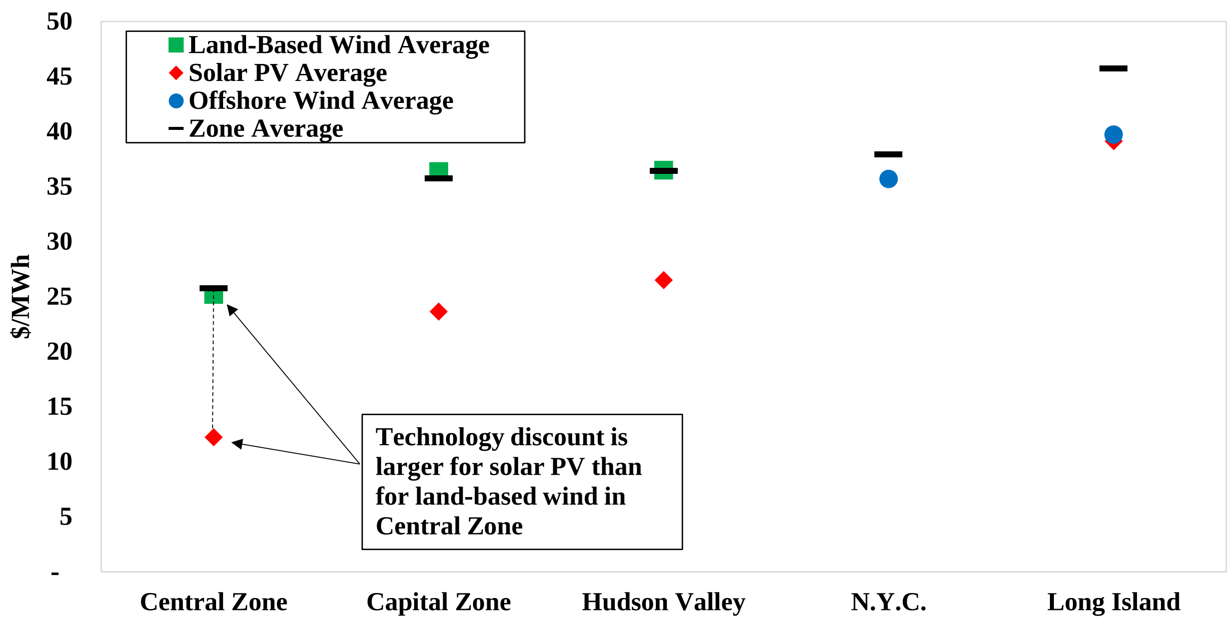
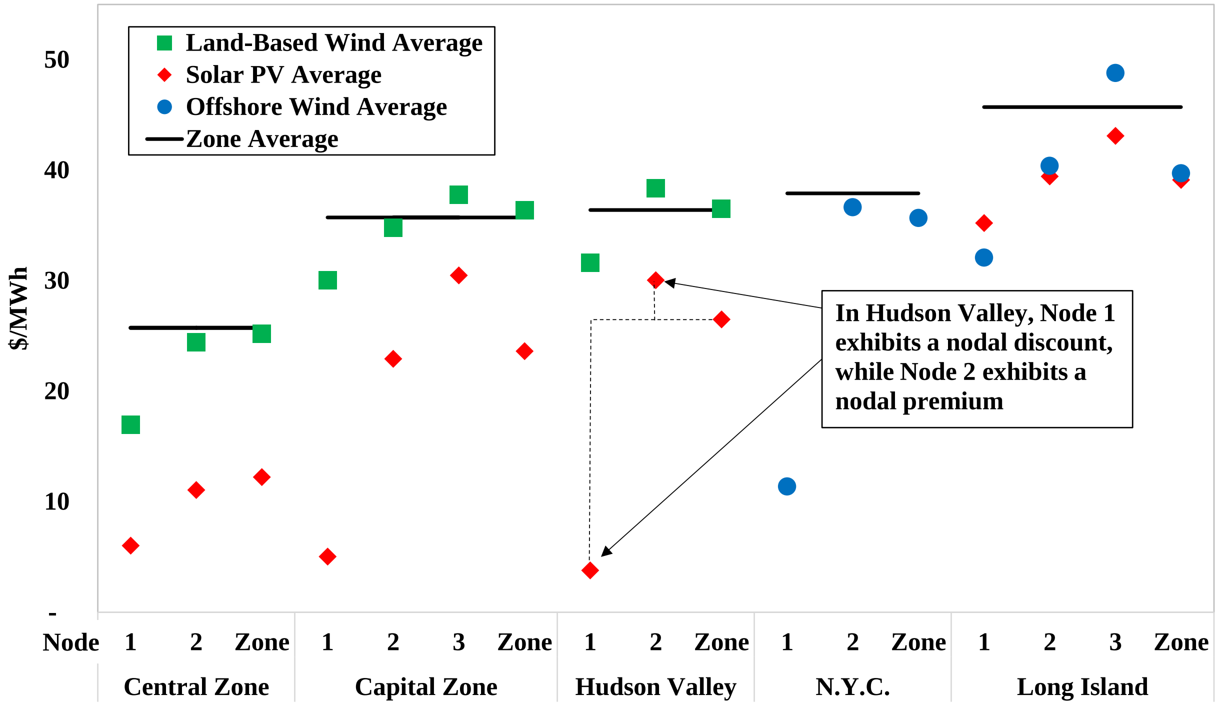


Figure 21: Nodal and Technology Discounts in CARIS 70x30 Case
For 12 Nodes and 5 Zones



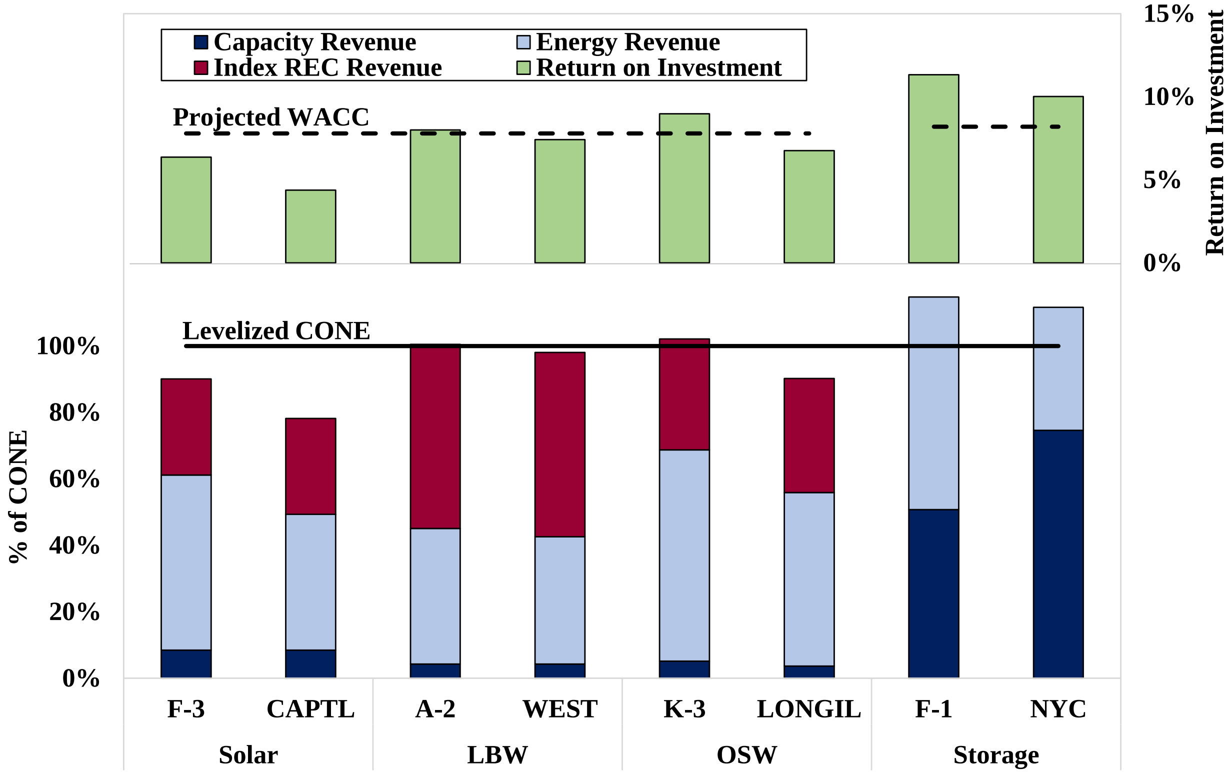
Several key observations can be drawn from the two figures above. First, the generation-weighted average LBMPs paid to all three renewable technologies are usually lower than the monthly average LBMPs on which the Index REC settlements are based—that is, we observe substantial technology discounts in many cases. For example, Figure 20 shows that the average Central Zone LBMP is $26 per MWh, and the generation-weighted average LBMP for solar PV in the zone is $12 per MWh, so the technology discount for solar PV in the Central Zone is $14 per MWh in this scenario.

Second, Figure 21 shows that the LBMPs for some nodes are significantly lower than the zones in which they are located, indicating areas where substantial nodal discounts are observed. For example, the generation-weighted average LBMP for solar PV is $27 per MWh in the Hudson Valley Zone and $4 per MWh at Node 1 in the zone, so the nodal discount for solar PV at Node 1 in the Hudson Valley Zone is $23 per MWh in this scenario.

Third, the technology discounts for solar PV are much larger than for land-based wind and offshore wind in this scenario. This indicates that the 18 GW of PV modeled in this scenario — assumed to meet half of the remaining state 70 percent target after resource-specific mandates — is inefficiently large and/or the quantities of assumed transmission, wind generation, and battery storage investment were inefficiently small. This indicates that the market can provide incentives that facilitate the most cost-effective investment for meeting the state policy goals.

The following figure evaluates the investment returns of six hypothetical projects from the previous figures. Figure 22 shows estimated net revenues compared to the levelized cost of new entry (CONE) for various technologies and locations in 2030 (using the same CARIS 70x30 Case as the previous figure). REC revenues are estimated using the state's Index REC methodology, assuming that the project offers an Index REC strike price equal to its annualized cost of entry. The figure also shows these values for two hypothetical battery storage projects.

Figure 22: Revenues of Renewable Projects in CARIS 70x30 Case



The figure shows that in this scenario:

- Solar PV in the Capital Zone (Zone F) and offshore wind in Long Island (Zone K) face substantial technology discounts, leading to relatively low investment returns (4.4 and 6.7 percent, respectively).
- Land-based wind in the West Zone (Zone A) would receive normal investment returns.
- The hypothetical solar PV and offshore wind projects at individual nodes exhibit substantial nodal premiums (rather than discounts). These indicate nodes where projects would receive higher returns than if they generated at prices consistent with the zone.
- The two hypothetical battery storage projects would receive high investment returns, underscoring that the CARIS 70x30 case included inefficiently low levels of battery storage resources (given the amount of intermittent generation that was included).

The results highlight the importance of revenues from NYISO markets in general for both storage and renewable resources. Under Index REC contracts, renewable developers accept risks related to congestion at their location and oversaturation at the times that their resource generates. This causes the revenue and investment returns to vary significantly by technology and location. Hence, the markets can guide investment towards the most valuable projects.

The results also show that the markets' prices can facilitate merchant storage investment in a high-renewable system. Revenues from the energy, ancillary services and capacity markets are sufficient for a new energy storage resource to earn its CONE at many locations in the 70x30 Case. Energy markets reward storage as the penetration of renewables increase because the battery can charge when renewable output is high and prices are low. Capacity prices are also likely to motivate investment in storage resources in key areas such as New York City.

B. Risks for Renewable Developers with Long-Term Contracts for Index RECs

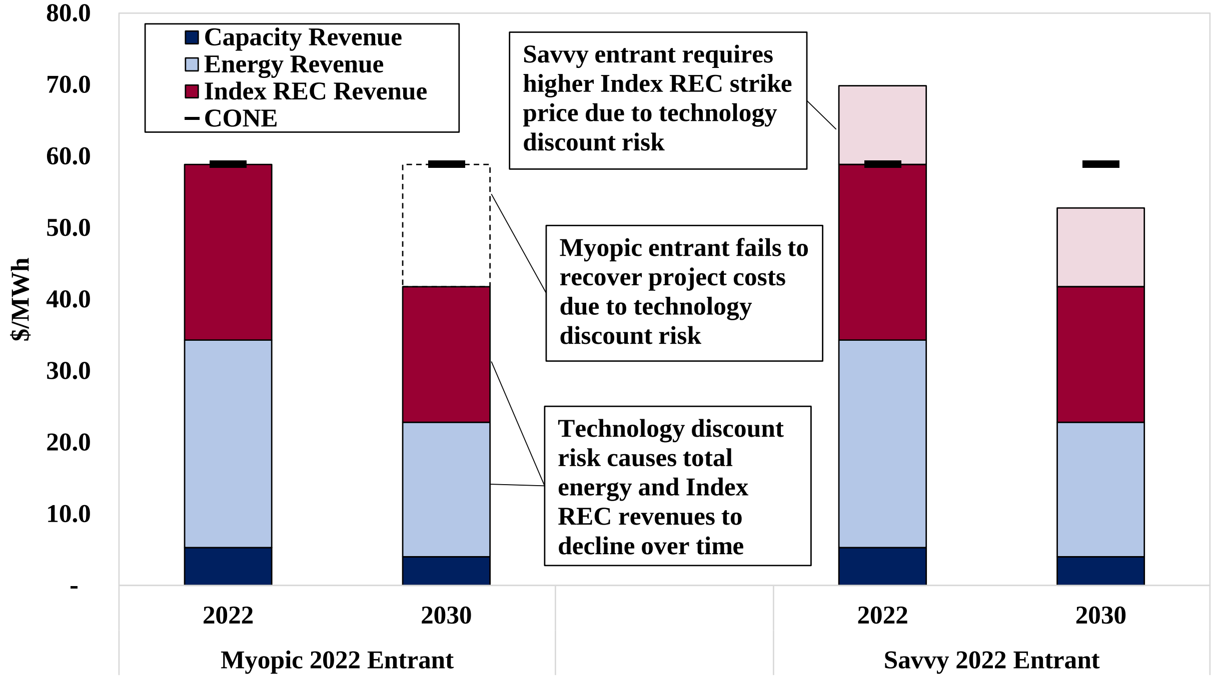
Investments in public policy resources that are not guided by competitive market signals could make achieving clean energy targets more difficult and expensive. Hence, even renewable developers under long-term contracts face significant risk from future investments that are not responsive to market conditions. The following analysis examines how investors are likely to respond to the risks presented future investment decisions.

Figure 23 below shows how revenues could change over time for a solar PV project entering service by 2022 and which continues to operate in 2030 as modeled in the CARIS 70x30 Case. This is shown for a solar PV project located at Zone F for two hypothetical investors:

- 'Myopic' entrant – This investor offers an Index REC strike price equal to its CONE (assuming that REC payments will balance out changes in market price over time); and
- 'Savvy' entrant – This investor anticipates that future investments will saturate the region with solar PV, requiring a higher Index REC strike price to account for this risk.

The myopic investor initially earns a normal rate of return on investment, but this drops 29 percent below its levelized cost of energy in 2030. Since the savvy investor anticipates the effects of future public policy initiatives, the savvy investor initially offers an Index REC strike price $11 per MWh higher than its levelized CONE to compensate it for lower returns in future years.

Figure 23: Impact of Future Entry on Near-Term Solar Project



If future investors are induced to enter (in spite of market signals) by higher subsidy levels, but the near-term investor does not receive increased subsidies, the near-term investor will be harmed by the resulting low price levels. As a result, firms considering whether to invest in the near-term may require a substantial premium in the form of a higher Index REC offer, or they may simply delay investing until they anticipate less risk resulting from future investment decisions. Indeed, this may be one reason why a large portion of renewable projects contracted by NYSERDA since 2018 have reportedly encountered delays in obtaining financing.[130,131]

Using transparent uniform market signals to promote clean technologies (e.g., with REC procurements that establish uniform prices regardless of entry date) would help reduce the financial risks associated with future investment. This is because uniform market signals cause future developers to naturally avoid investing in oversaturated technologies and locations.

130 Of the 66 renewable projected selected by NYSERDA for long-term contracts between 2018 and 2020, none are yet in service. Contracts awarded in NYSERDA's 2017 Tier 1 REC solicitation had an initial commercial operation date of in November 2019. This date may be extended up to several years, an option which has been pursued by every recipient. See Sustainable Energy Advantage, *Renewable Energy Standard Program Impact Evaluation and Clean Energy Standard Triennial Review*, September 2020, at p. 8.

131 NYSERDA noted in 2020 that "a substantial portion of the projects within this cohort have encountered delays in obtaining financing" for reasons that include declining market prices and permitting. A program evaluation commissioned by NYSERDA lists "financial viability of the project at the bid price" as a potential driver of project delays and attrition. See NYSERDA August 10, 2020 Petition in NYPSC Case 15-E-0302, at p. 7. As described in this subsection, conversion of prior Fixed REC contracts to Index RECs partly mitigates but does not eliminate renewable projects' revenue risks.

Future developers would also be encouraged to invest in adaptive solutions that complement renewable entry, such as storage or clean dispatchable technologies.

Ultimately, policy initiatives that are not aligned with the market and provide higher payments to future developers impose significant risks on near-term clean energy resource developers, thus making it more difficult to achieve public policy goals. Policy initiatives that work through transparent uniform market signals reduce the associated risks and are likely to achieve their objectives at a lower overall cost. In the next subsection, we discuss the role of BSM in the capacity market to provide efficient incentives for investments that help integrate renewable resources.

C. Role of BSM Measures in Reducing Risk for Investment in Flexible Resources

The BSM rules have helped ensure that out-of-market investment did not reduce capacity prices below competitive levels, and they have fostered investor confidence in the market and the competitiveness of future prices. The BSM measures were originally designed to prevent entities from reducing capacity prices below competitive levels by subsidizing uneconomic new entry of conventional generation. BSM measures are not intended to deter states from promoting clean energy objectives, so it is important to evaluate the rules to ensure that they do not impede these objectives.

Removing BSM rules altogether would ultimately raise costs to consumers because the risk of artificial and sustained capacity surpluses would cause suppliers to require higher returns on their capital. The increase in the cost of capital is ultimately borne by consumers in the form of higher prices. Indeed, we found that eliminating BSM provisions would raise costs to consumers by $24 million in 2030 in a scenario developed by NYSERDA and NYDPS' consultants to study various resource adequacy alternatives.[132] In addition, eliminating BSM entirely could require increased reliance on State-directed long-term contracting for capacity, which would be costly and fail to coordinate efficient investment in new resources or retirement of existing resources.[133]

Hence, we support retaining BSM rules that strike a reasonable balance between two objectives:

- Protecting the integrity of the market by limiting artificial capacity price reductions, and
- Facilitating the state's efforts to shape the characteristics of its resource mix to achieve its energy and environmental policy objectives.

The effects of adding large quantities of subsidized out-of-market entry on capacity prices could be offset by resource retirements that can help maintain the balance of supply and demand. In

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132 See page 11 of our August 2020 comments in Proceeding on Motion of the Commission to Consider Resource Adequacy Matters.

133 See discussion of pitfalls of state-directed long-term contracting mechanisms in our reply January 2020 reply comments at p. 10 in the Proceeding on Motion of the Commission to Consider Resource Adequacy Matters.

recent years, the state has not only provided subsidies to cleaner resources, but also used its regulatory authority to cause the retirement of high-polluting conventional generation. These actions, if coordinated properly, can avoid inefficient supply surpluses. The NYISO has already proposed and implemented changes to the BSM provisions to enable entry of renewable resources to the extent existing resources leave the market due to state regulations. In the CY19 BSM evaluations, over 170 MW of solar generation and 38 MW from battery storage were determined to be exempt from Offer Floors in large part due to the DEC's Peaker Rule-related retirements.

In addition, the "bank" of Renewable Entry Exemptions in New York City is already likely sufficient to exempt over 1600 MW of offshore wind, and the bank will increase with the announcement of additional retirements resulting from the DEC Peaker Rule. However, given New York's ambitious agenda to promote clean energy policies, the changes we discuss in the next subsections will help ensure a reasonable balance between the above two objectives.

D. Initiatives that would Reduce Conflict between State Policies and BSM Measures

In recent years, we have recommended a number of measures that can promote the state's energy transition. This subsection summarizes our recommendations and discusses how they can promote the alignment of the NYISO's markets, and the BSM measures in particular, with State public policy goals. In this subsection, we discuss:

- Part A Test Enhancements filing – This proposal, which is currently on appeal, would enable Public Policy Resources ("PPRs") to be tested first and to be exempted when the PPRs would not result in a capacity surplus that is above the specified threshold.
- ICAP Accreditation improvements – These would facilitate new entry of PPRs by recognizing that some resources receive excessive credit for their capacity relative to its marginal reliability value. Addressing this issue by accrediting all resources based on their marginal reliability value will allow more PPRs to enter the market unmitigated.
- Energy and ancillary services market enhancements – These enhancements would increase compensation for flexible resources (e.g., batteries) and increase economic pressure to retire inflexible and inefficient existing units.
- BSM Test Improvements – Our recommendations would improve the implementation of BSM evaluations. These would enable the evaluations to better reflect the costs and revenues of PPRs and provide appropriate amounts of renewable entry exemptions.

Taken together, these measures could help achieve the State's goals cost-effectively, while preventing inefficient capacity price reductions below competitive levels.

Part A Test Enhancements

We worked with the NYISO and its stakeholders in developing a set of enhancements to the Part A test of the BSM evaluations.[134] New entrants would be exempted from BSM 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 PPRs to be tested under the Part A test ahead of non-PPR entrants.[135] Hence, the NYISO's proposed rules would enable PPRs to avoid mitigation as long as sufficient quantities of existing capacity exit the market and/or demand growth leads to higher capacity requirements.

As the regulation-driven retirements or economic retirements increase in the future, the 'headroom' available for PPRs to enter without being subject to BSM will also increase. In addition, these enhancements will promote bilateral agreements whereby an existing generator can retire and transfer its CRIS to a PPR. Such an arrangement would enable the PPR to enter without being subject to mitigation if the retirement of the existing resource would raise forecasted price levels enough for the PPR to pass the exemption test.

ICAP Accreditation

In this report, we recommend that the NYISO revise its capacity accreditation rules to compensate resources in accordance with their marginal reliability value (see Recommendation #2020-3). The marginal reliability value of individual resources depends on their availability when capacity margins are tightest, based on a standardized evaluation using NYISO's resource adequacy model. A proposed approach to calculating resource capacity value is presented in Section VII.E.

Improved capacity accreditation would affect the capacity compensation of various resource types. Existing thermal generators whose reliability contributions are currently overvalued – including units with long lead times and low availability, as well as very large units – would see a reduction in capacity value. Additionally, capacity value of intermittent renewables, storage and demand response resources would change over time as penetration of these resources increases. Improving accreditation would impact BSM evaluations in several ways:

- It would reduce the capacity surpluses by eliminating overvaluation of some resources, increasing the headroom available for BSM exemptions in the Part A and Part B tests.
- The revenues of existing inflexible generators whose capacity is currently overvalued would decline, encouraging these units to retire economically. This would increase the headroom available for BSM exemptions in the Part A and Part B tests.

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134 The NYISO filed these provisions with the Commission on April 30, 2020, and filed its response to FERC's Deficiency Letter on July 9, 2020.

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

- It would avoid overstating PPRs' capacity accreditation, which are likely to fall as penetration increases, allowing larger quantities of PPRs to enter unmitigated.

Energy & Ancillary Services Pricing Enhancements

We make several recommendations in this report that would shift revenues from the capacity market to the energy and ancillary services markets. These recommendations would increase the financial returns for resources that perform flexibly and reliably. They would also reduce overcompensation of inflexible units, thereby encouraging such units to retire economically. Specifically, we evaluated the effects of the following recommendations in Section VIII.C:

- 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. For example, batteries that improve system utilization by managing transmission security concerns caused by offshore wind would be compensated for the value of this service.
- 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 and respond to immediate needs.

These recommendations would increase energy and reserve prices in key hours and locations, while reducing capacity market prices.[136] As Figure 18 demonstrates, this would improve the economics of flexible resources, such as battery storage or new CTs (which would facilitate their exemptions under the Part B test), while increasing the economic pressure on older inflexible units to retire (which would facilitate PPR exemptions under the Part A and Part B tests).

BSM Test Improvements

Our CY19 and past BSM reports have identified a number of concerns with assumptions and procedures that are currently used in the BSM evaluations. The following is a summary of some of our recommendations that would improve the BSM evaluations of PPRs:[137]

- The NYISO's tariff requires it to consider the revenues that a project would receive from sale of RECs and other energy-related services (e.g. distribution-level reliability

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136 This is because higher energy and reserve prices reduce the 'missing money' of the proxy unit that is used to establish the capacity market demand curves.

137 In addition, our CY19 BSM report discusses other recommendations to: (a) improve the price forecasts used in the evaluation, (b) enhance the accuracy of project cost and revenue estimates, and (c) improve the test procedure so the most economic projects are exempted. See our report on BSM evaluation of CY19 projects.

benefits).[138] This year, the NYISO is providing additional transparency to stakeholders about its procedures for estimating the competitive proxy values for REC revenues and distribution-level reliability services.

- Our CY19 BSM evaluations highlight potential improvements in the procedures for determining the size of the REE bank and for awarding MW from the bank to renewable projects. The NYISO has indicated that it will provide proposals to address issues in granting REEs.
- The NYISO Tariff requires BSM evaluations to assume that all projects being tested will be placed into service three years from the start of the study. In practice, the assumed entry date has at times been less than a year from the date of the BSM determination results.[139] The costs of many types of PPRs are projected to decline in the future. Hence, utilizing an earlier date than the likely entry date could lead to inflated estimates of project costs (relative to the actual costs), thus reducing the likelihood of securing a BSM exemption. Accordingly, we recommended the NYISO modify its Tariff to address this issue.

E. Impact of Recommended Enhancements on Future Development of Clean Resources

The BSM rules provide several avenues for PPRs to obtain exemptions from mitigation and sell capacity. We recommend enhancements in the previous subsection that would enable additional BSM exemptions, while satisfying the objective of the BSM measures to prevent artificial surpluses and associated price reductions. These enhancements are distinct from a blanket exemption for all PPRs because the enhancements would still preserve the ability of capacity markets to provide appropriate price signals for market-based investment in flexible resources. In this subsection, we discuss the potential impact of the recommended enhancements on BSM evaluations for PPRs in New York City and the G-J Locality.

Impact on New York City BSM Evaluations

Figure 24 shows the projected availability of exemption headroom for offshore wind and energy storage resources in New York City by 2030 under the provisions of the Renewable Entry Exemption and the Part A Test exemption (assuming that the NYISO's Part A Test Enhancements proposal is adopted). The figure shows the available headroom under the following three scenarios that illustrate the effect of potential retirements of existing resources:[140]

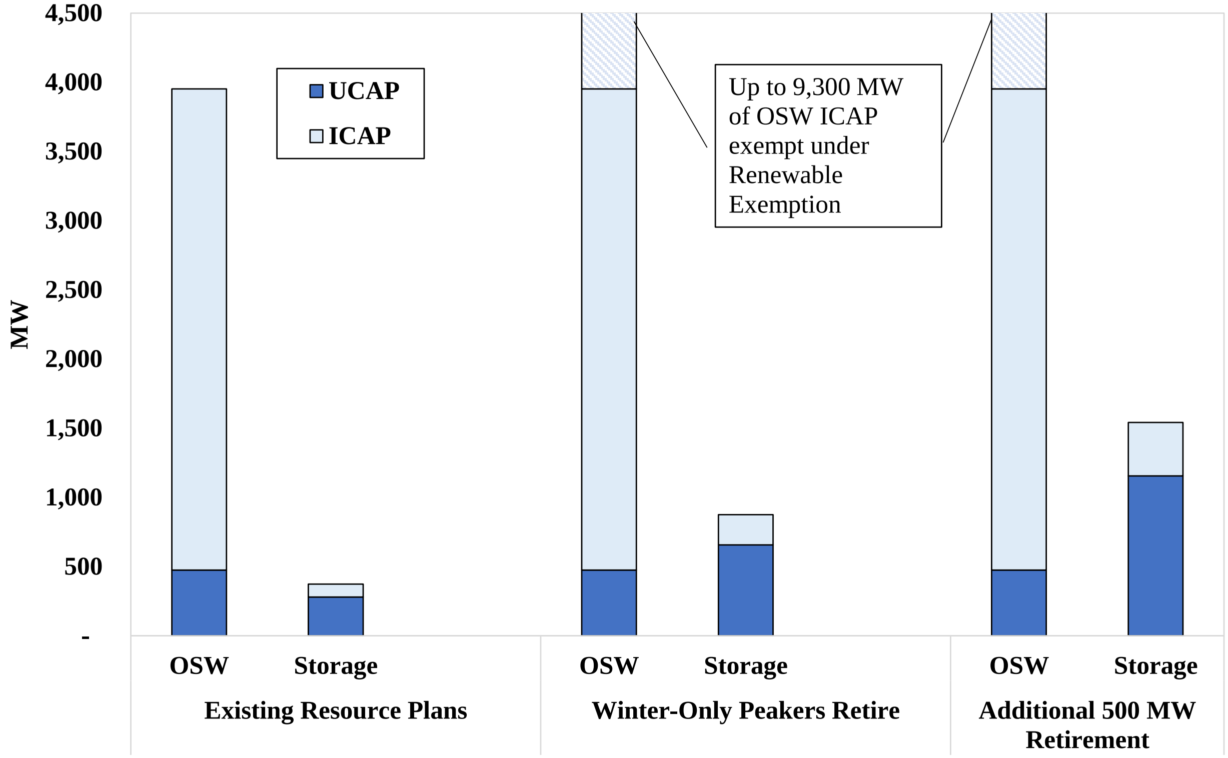
138 Considering RECs in the BSM evaluations will benefit renewable resources, while battery resources, where applicable, could benefit from including distribution-level reliability benefits.

139 For instance, the projects evaluated as part of the Additional SDU studies are yet to receive their final determinations although their assumed start date is May 2022.

140 In each scenario we assume peak load growth based on the 2021 NYISO Gold Book, a locational capacity requirement of 86 percent, and summer ICAP/UCAP translation factor of 7.1 percent, based on the latest BSM Forecast. We assume entry of public policy resources based on the Zero Emissions Electric Grid in New York by 2040 Study prepared by Siemens for NYSERDA and NYDPS ("Zero Emissions Study").

- *Existing Resource Plan scenario* – assumes that certain resources retire or operate only in the non-ozone season (October through April), based on their current DEC Peaker Rule compliance plans, and no other retirements ever occur. In this scenario, 533 MW (summer ICAP) of NYC units retire and 845 MW operate only in the non-ozone season.[141]
- *Winter-only Peaker Retirement scenario* – assumes that the 845 MW of units operating only during the non-ozone season to comply with the DEC Peaker Rule retire by 2030. These units will lose the majority of their net revenues when they cease operating in peak summer months, when capacity prices and energy margins are highest.
- *Additional 500-MW Retirement scenario* – assumes that an additional 500 MW of aging steam turbine capacity retires based on economics.

Figure 24: Projected Renewable and Part A Exemptions Available by 2030 in NYC



The results of this analysis show that with realistic future retirements, BSM rules are likely to provide exemptions for large quantities of public policy resources in New York City, especially offshore wind generation and battery storage resources.

Based on the Zero Emissions Study, we assume 3,952 MW of offshore wind in New York City by 2030 and that effective UCAP values of offshore wind and 4-hour energy storage by 2030 are 12 percent and 75 percent, respectively.

141 See NYISO 2020 Gold Book Table IV-6.

Offshore Wind Resources - As the capacity value of offshore wind declines over time due to rising penetration, a small amount of exemptions in UCAP terms can result in BSM exemptions for a very large amount of offshore wind (nameplate) capacity. Nearly 4 GW of offshore wind interconnecting in New York City is likely to be exempt under the current REE provisions without any retirements beyond existing plans. Further, if additional gas turbines that indicate they will operate only outside of the May-September ozone season were to retire, over 9 GW of offshore wind resources interconnecting in New York City could receive exemptions. This would be sufficient to cover the state's entire target of 9,000 MW of offshore wind by 2035, although a large portion of this will enter Long Island rather than New York City.

Battery Storage Resources - The quantity of Part A Test headroom available to storage resources depends on retirement of other surplus resources. The estimated storage exemption in ICAP terms ranges from approximately 370 MW (if no units retire beyond existing plans) to over 870 MW if units affected by the Peaker Rule retire. Additional retirement of aging steam turbine units would increase this quantity even further. Figure 24 shows over 1,500 MW of storage resources eligible for exemption if an additional 500 MW of existing capacity retires by 2030. For sake of comparison, the current storage procurement target for Con Edison is 300 MW and the Zero Emissions Study commissioned by NYDPS projected 879 MW of energy storage in NYC by 2030.

There is currently over 3,800 MW of steam turbine capacity in New York City, of which over 1,200 MW will be over 70 years old by 2030. Many of these units already are likely to face challenging economics in the long term, particularly if the recommendations related to E&AS Enhancements and ICAP Accreditation are adopted. Hence, the potential headroom and available exemptions for PPRs could be much larger than shown in the figure.

Impact on G-J Locality BSM Evaluations

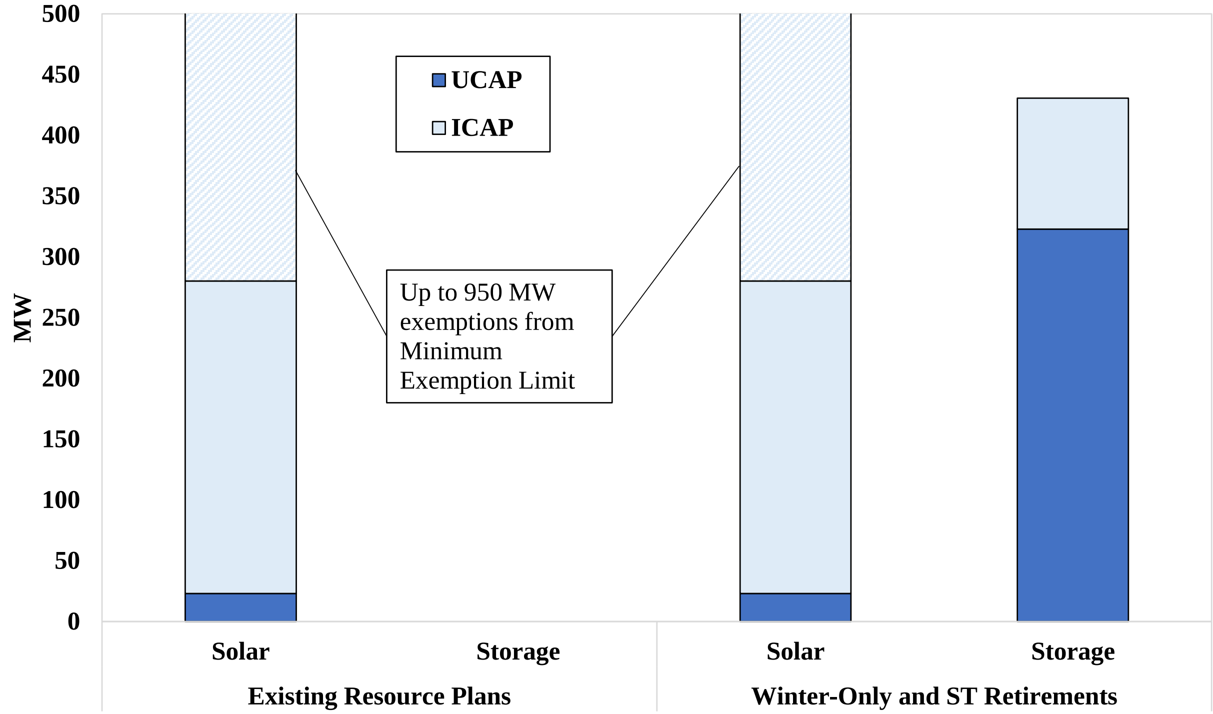
Figure 25 shows projected headroom for PPRs under the REE rules and Part A Test in the G-J Locality by 2030.[142]

- *Existing Resource Plan scenario* – assumes that 571 MW (summer ICAP) of units in zones G and J retire and 845 MW operate only in the non-ozone season based on current DEC Peaker Rule compliance plans, and no other retirements occur.

142 Based on the Zero Emissions Study, we assume that a total of 257 MW (ICAP) of solar projects enter Zone G, including 173 MW that have already received Renewable Entry Exemptions. We further assume that 3,952 MW of offshore wind and 879 MW of energy storage enter in Zone J, which reduces headroom in Zone G. The locational capacity requirement for Zone G-J is assumed to decline to 86 percent following completion of the AC Transmission Projects. The effective UCAP of solar projects is assumed to decline to 9 percent of ICAP by 2030 based on the Zero Emissions Study.

- *Winter-Only and ST Retirements scenario* – assumes that the 845 MW of units in Zone J operating only during the non-ozone season retire by 2030, and that an additional 500 MW of older steam units retire in each of Zone J and Zone G.

Figure 25: Projected Renewable and Part A Exemptions Available by 2030 in G-J Locality



Solar Resources - Figure 25 shows that a large amount of solar capacity is likely to be eligible for a REE in Zone G. This is true even if there is surplus capacity in Zone G because of the Minimum Renewable Exemption Limit, which is estimated to allow approximately 77 MW (UCAP) to enter in each Class Year (i.e., 154 MW ICAP of solar PV). The Zero Emissions Study commissioned by NYDPS projected 257 MW of solar PV in Zone G by 2030. A total of 173 MW (ICAP) of solar PV has already received Renewable Entry Exemptions in Zone G.

Battery Storage Resources - Part A Test headroom is likely to be low in the G-J Locality without additional retirements because of large supply surpluses and planned transmission projects that are likely to reduce the region's capacity requirement. Hence, if no additional resources beyond those indicating retirement in their compliance plans were to leave the market, the ability of storage resources to receive BSM exemptions under the Part A test may be limited. However, Zone G also has a large amount of inflexible steam turbine capacity, some of which will face retirement pressure if recommended market changes are adopted. The Zero Emissions Study commissioned by NYDPS projected 344 MW of energy storage in Zone G by 2030.

Although the Part A test headroom for storage resources may be limited, we have recently found that the economics of storage projects in Zone G are likely to support Part B exemptions in the coming years as storage projects costs decline.[143] Further, implementing our recommended energy market enhancements (see VIII.C.3) could enable the NYISO markets appropriately value storage resources, and exempt storage resources in many locations. Lastly, if a resource has a high value in addressing other system needs – such as helping to reduce renewable curtailment or providing local distribution system benefits – then this value would be recognized in the BSM evaluation and increase the chances of a Part B exemption.[144]

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143 See August 24, 2020 comments of Potomac Economics in NYPSC Case 19-E-0530.

144 For example, if some portion of renewable generation is curtailed, local LBMPs will be negative, reflecting the value of RECs and federal subsidies. Batteries that reduce curtailment by charging in such hours are therefore compensated appropriately based on the environmental value reflected in the negative price.

X. 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 ten 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 Gas Turbines in Responding to Start-Up Instructions
- Dispatch Performance of Duct-Firing Capacity
- Use of Operating Reserves to Manage New York City Congestion
- 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 XII 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 need for energy and ancillary services. 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: [145]

- *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

Although regulation shortages were still most frequent in 2020, the frequency fell from 4.5 percent of intervals in 2019 to just 1.8 percent of intervals in 2020. This reflected lower load levels, fewer hours of tight operating conditions, and lower energy prices (which reduce the opportunity cost of providing ancillary services). Reserve shortages continued to occur very infrequently in 2020. While infrequent, shortages of regulation and operating reserves collectively increased average LBMPs by 3 to 5 percent in 2020.[146] 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, such as 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).[147] Accordingly, we recommend the NYISO modify the market models to dynamically determine the optimal amount of reserves to hold inside:[148]

- 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.

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145 Our previous reports also evaluated market performance during demand response deployments – a third type of shortages. In 2020, the NYISO did not deploy reliability demand response resources, so the performance under this type of shortage is not evaluated in this report.

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

147 See, for example, Appendix Section V.G for our analysis of New York City requirements during TSAs.

148 See Recommendation #2015-16 in Section XII. Section V.L of the Appendix provides a potential mathematical modeling approach.

- 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. We estimate that under-scheduled physical energy averaged nearly 1 GW per hour in 2020.[149]

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 have been implementing Pay For Performance ("PFP") rules since 2018, which provide incentives similar to extreme shortage pricing. The analysis provided in Figure 26 examines the shortage pricing incentives that will be provided by NYISO compared to its neighbors with PFP rules.[150] The figure shows that:

- In ISO-NE, the Performance Payment Rate levels are $3,500 per MWh currently and will rise to $5,455 per MWh in 2024.[151] These payments are in addition to reserve shortage pricing, which starts at $1,000 per MWh, resulting in total incremental compensation during reserve shortages potentially over $8,000 per MWh.
- In PJM, the Performance Rate is set to be approximately $3,000 per MWh in addition to real-time shortage pricing levels of $2,000 per MWh for each of its 10-minute, 30-minute, and local reserve requirements. This will provide incentives of up to $9,000 per MWh during a shortage of both 10-minute and 30-minute reserves.

In contrast, the incentives provided by NYISO during reserve shortages will be much weaker at the borders with the two markets even after NYISO implements recently approved increases in its shortage pricing incentives.[152] During shortages of 30-minute reserves, NYISO will invoke statewide shortage pricing of up to $750 per MWh. During deep shortages of multiple 30-minute and 10-minute reserve requirements, NYISO will invoke statewide shortage pricing levels that could exceed $2,000 per MWh under very severe conditions. Figure 26 compares shortage pricing levels in PJM and ISO-NE with NYISO including adders for locational reserve requirements near each border.

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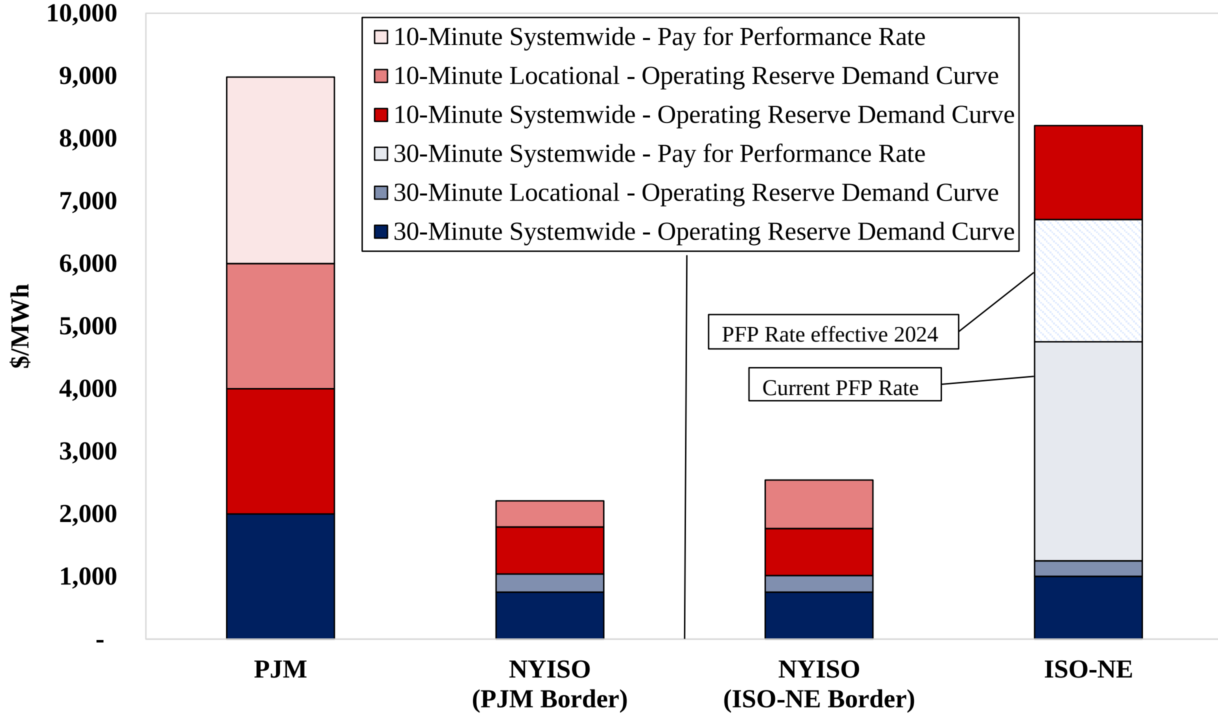
149 See Figure A-97 in the Appendix for this analysis.

150 See Figure A-91 in the Appendix for description of this chart.

151 See ISO New England Tariff Section III.13.7.2.

152 See FERC docket ER21-1018. The quantity of NYCA 30-minute reserves that is assigned the current maximum shadow price of $750/MWh will increase from 62.5 percent of the requirement to 75 percent of the requirement. Under some circumstances, this will reduce the need for OOM dispatch of internal generation, emergency purchases, and export curtailments to maintain reserves.

Figure 26: Shortage Pricing in NYISO vs. Neighboring Markets



During deep shortages of 30-minute reserves, NYISO shortage pricing including locational adders will reach up to $1,015 per MWh, while PJM will use $2,000 per MWh and ISO-NE will use over $6,700 per MWh during slight 30-minute reserve shortages. In deep shortages of 10-minute reserves, NYISO shortage pricing including locational adders will reach up to $2,540 per MWh, while PJM will use approximately $9,000 per MWh and ISO-NE will use over $8,200 per MWh during slight 10-minute reserve shortages. Hence, when NYISO is in a much less reliable state than PJM or ISO-NE, market participants will have strong incentives to export power from (or reduce imports to) NYISO. This disparity will either undermine reliability in New York or require NYISO operators to engage in out-of-market actions to maintain reliability.

Our 2018 State of the Market report found that weak market incentives on the NYISO side led to OOM actions by NYISO during the first-ever PFP event in the ISO-NE market.[153] If the NYISO reserve demand curves provided stronger incentives, these OOM actions likely would not have been necessary.

Even after recently approved changes, 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

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

conditions. To ensure these levels are reasonable, the NYISO should also consider the Value of Lost Load ("VOLL") 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.[154]

Transmission Shortages

During shortages of transmission capability (i.e., when power flows exceed a facility's transmission limit) the market should set efficient prices that reflect the severity of shortage. In 2020, transmission shortages occurred in nearly 8,000 market intervals, so they play a significant role in setting transparent prices that reflect the effects of transmission bottlenecks across the system. Most transmission shortages cleared on the first ($350 per MWh for up to 5 MW) step on the Graduated Transmission Demand Curve ("GTDC"). These are typically small, transient shortages that do not adversely affect reliability because the NYISO uses a Constraint Reliability Margin ("CRM") of 10 to 100 MW that builds in a buffer between modeled flows and the applicable transfer limit for each facility.[155] Constraint relaxation was relatively infrequent in 2020, occurring in just 4 percent of all transmission shortages.[156]

In this report, we identify two ways in which transmission shortages are not efficiently reflecting in the scheduling and pricing of individual resources. First, the current GTDC is not well-aligned with the CRMs used for different facilities. 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.[157] Therefore, we have recommended that the NYISO replace the current single GTDC with multiple set of 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.[158] The NYISO has proposed modifications to the GTDC that would be a significant improvement over

154 See Recommendation #2017-2 in Section XII.

155 A CRM value of 10 MW is used for 115 kV constraints, while a default CRM value of 20 MW is used for most facilities at higher voltage levels.

156 Since June 2017, the use of constraint relaxation for non-zero CRM constraints has been limited to shortages of 20 MW or greater after the second ($1,175 per MWh) step of the GTDC. Constraint relaxation resolves a constraint 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. Constraint relaxation is evaluated in Figure A-92 .

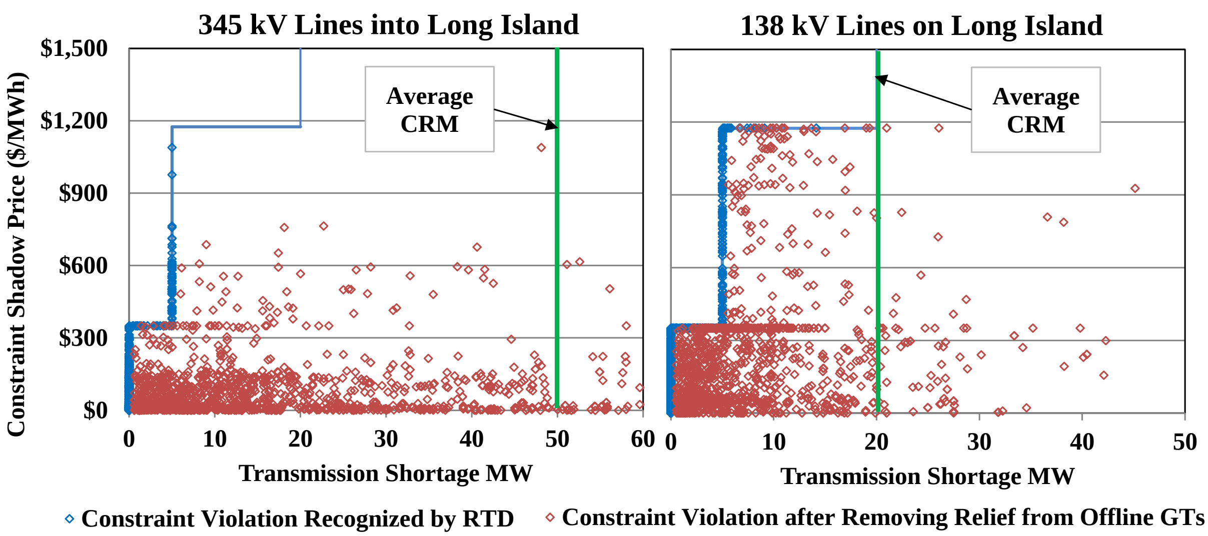
157 See Table A-11 in the Appendix for a more detailed description.

158 Recommendation #2015-17 in Section XII.

the current GTDC for at least two reasons.[159] First, the proposed GTDC would increase more gradually than the current GTDC, which will reduce unnecessary 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.

Second, we have found that the constraint shadow prices resulting from the so-called "offline GT price-setting" were not well-correlated with the severity of transmission constraints, leading to inefficient congestion prices during such conditions. Figure 27 shows our analysis on the 345 kV and 138 kV facilities on Long Island.[160]

Figure 27: Transmission Constraint Shadow Prices and Violations
With and Without Relief from Offline GTs, 2020



"Offline GT price-setting" treats offline GTs as able to respond to dispatch instructions even though they actually cannot do so. This leads to large differences between modeled flows and actual flows, limiting the ability of the real-time market models to maintain transmission security in areas that rely more on peaking units such as Long Island. Consequently, the NYISO uses significantly higher CRMs for key transmission facilities such as the Dunwoodie-to-Shore Road and Sprainbrook-to-East Garden City 345kV lines from upstate to Long Island. Thus, the use of offline GT pricing indirectly leads the NYISO to constrain transmission flows at artificially low levels in areas that rely more on peaking units such as Long Island, leading to unnecessary generation dispatch and inflated production costs. Therefore, we also recommend the NYISO eliminate offline fast-start pricing from the real-time dispatch model.[161]

159 See "Constraint Specific Transmission Shortage Pricing", by Kanchan Upadhyay, at November 21, 2019 MIWG meeting.

160 See Figure A-93 in the Appendix for description of the chart.

161 See Recommendation #2020-2.

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 42 percent of the capacity committed by the real-time market model in 2020 was clearly economic over the initial commitment period (one hour for GTs), generally consistent with recent years.[162] This, however, likely understates the share of GT commitments that are efficient because the efficient commitment of a gas turbine reduces LBMPs in some cases such that the LBMP revenue it receives is less than its offer.

Nonetheless, there were many commitments in 2020 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.[163]
- The fast-start price-setting rules did not usually reflect the start-up and other commitment costs of the gas turbine in the price-setting logic until the end of 2020.[164]

The NYISO implemented the "Enhanced Fast-Start Pricing" project on December 15, 2020, which: (a) extended the existing logic (applied previously only to Fixed Block fast-start units) to all fast-start resources; and (b) included the start-up and minimum generation costs of all fast-start resources in the LBMP calculation. This will likely lead real-time prices to better reflect system conditions and better performance incentives for flexible resources when fast-start units are deployed.

C. Performance of Gas Turbines in Responding to Start-Up Instructions

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.

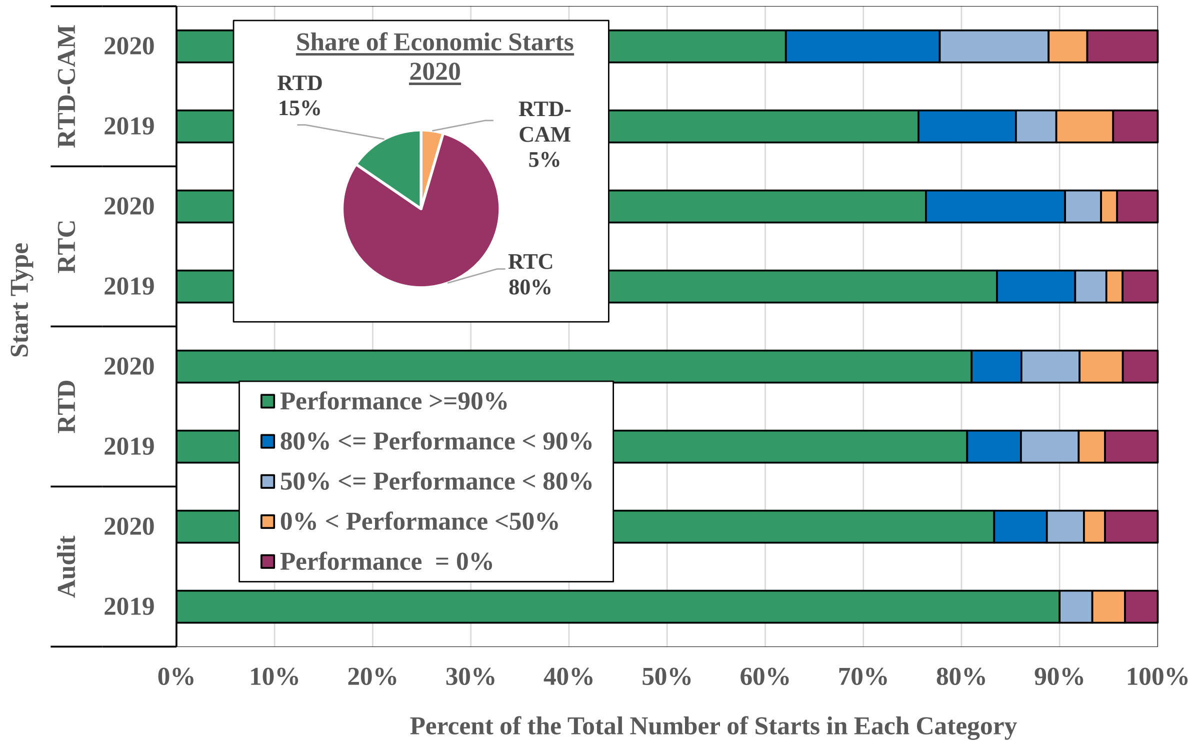
162 See Figure A-80 in the Appendix for details of this analysis.

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

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

This section analyzes the performance of gas turbines in responding to start-up instructions in the real-time market. Figure 28 summarizes the performance of GTs in responding to start-up instructions resulting from economic commitment by RTD, RTD-CAM, and RTC (excluding self-schedules) in 2019 and 2020.[165] The figure also compares the performance for each economic start category to the performance of the associated units in the NYISO auditing process.

Figure 28: Average GT Performance by Type after a Start-Up Instruction
Economic Starts vs Audit, 2019-2020



Gas turbines exhibited a wide range of performance in responding to start-up instructions in recent years. Among all economic starts, gas turbines exhibited the worst average performance during RTD-CAM starts. In 2020, approximately 22 percent of all RTD-CAM starts performed below 80 percent at the evaluation time (i.e., 10-minute mark following the start-up instructions), including 7 percent that failed to start. On the other hand, only 9 to 14 percent of other economic starts performed below 80 percent. Although RTD-CAM starts accounted for just 5 percent of all economic starts, the started GT capacity was typically needed to resolve certain system emergencies, so the poor performance can aggravate tight system conditions.

GT start-up performance was generally comparable between 2019 and 2020 except that several 10-minute GTs performed worse in 2020. Some 10-minute GTs shifted from a low-90s percent performance in 2019 to a high-80s percent performance in 2020. Other 10-minute GTs saw a

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

shift from the higher-performing 80 to 90 percent category in 2019 to the poorer-performing 50 to 80 percent category in 2020. Nonetheless, GT startup performance is still significantly better than before 2018 because of retirements and IIFOs of poor performing units. This trend may continue as older units continue to leave the market.

For example, 90 units had an average performance of 90 percent and above in audits, while only 73 units achieved similar performance when responding to start-up instructions from the market model. On the other end of the spectrum, a small number of units (five) performed poorly during their audit, but performed at a high level during the year showing that even the best performers may have an anomalous poor start.

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 tend to perform poorly still earn most of their net revenue from the sale of operating reserves.[166] Because operating reserve revenues are not sensitive to suppliers' expected performance, the market does not provide efficient performance incentives to reserve providers.

The NYISO has enhanced its procedure to audit each GT more frequently (either once per Capability Period or at least once per Capability Year) to ensure that they are capable of providing these reserve services. We reviewed NYISO audit results and found that the frequency of GT audits has increased markedly in 2020. There have been 251 audits (on 136 unique GTs), much higher than in prior years, which saw an average of 49 GT audits performed annually from 2016 to 2019. Units with relatively poor performance and/or infrequent market-based commitment have been audited much more frequently under these new procedures.

Further enhancements to this audit process could be beneficial such as:

- Using performance during reserve pick-ups or economic starts in lieu of audits would reduce out-of-market actions and uplift costs.
- Requiring the unit owner to bear the cost of being audited. Audits enable a resource to remain qualified to sell operating reserves, so they may be considered a cost of participation rather than a cost that should be borne by customers through uplift. This is similar to the practice of requiring individual resource owners to bear the costs of DMNC testing, since it enables them to qualify to sell capacity.
- Since units that perform well during audits may still perform poorly during normal market operations, it may be necessary to suspend or disqualify poor performers. 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.[167]

166 See Appendix Section 0.A for more information about the net revenue of gas turbines.

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

D. Dispatch Performance of Duct-Firing Capacity

Most combined cycle units in New York have a duct burner, which uses supplementary firing to increase the heat energy of a gas turbine's exhaust, making it possible to increase the output of a downstream heat-recovery steam generator. This additional output can be offered into the energy market as a portion of the dispatchable range of the unit. There are a total of 42 units across the state that are capable of providing 761 MW of duct-firing capacity in the summer and 793 such MW in the winter, collectively.[168] However, most duct-firing capacity is not capable of following a five-minute dispatch signal. The inflexibility of duct-firing capacity leads to two problems for these combined cycle generators:

- Reduced energy offers – Some combined cycle units with a duct burner do not offer it into the real-time market, while others simply "self-schedule" this capacity in a non-dispatchable way.
- Reduced regulation offers – Some units face the risk of needing to regulate into their duct-firing range, where they may have limited ability to respond to AGC signals or may have higher operating costs and outage risks. [169]

Figure 29 outlines a stylized example of a combined cycle unit in its duct-firing range. The three shaded areas show the percentage of: (a) the total station output that comes from the minimum operating level, (b) the dispatchable range of just the baseload portion of the unit, and (c) the additional capacity of the duct-firing range. Two lines show the unit's instructed and actual output levels when the unit is instructed to ramp through the duct-firing range to it upper operating limit. The upper panel of the chart shows the difference between the instructed MW and actual MW and as a percentage of the duct-firing range.

The case study highlights that duct burners:

- Take Time to Start-Up – The unit does not begin to ramp up until more than ten minutes after it receives a start instruction at 15:40.
- Cannot Comply with Tariff Requirements for Dispatchable Units – The tariff requires ramp rate bids to be no less than one percent of the generator's operating capacity per minute.[170] However, this unit ramps at a maximum of 0.5 percent per minute in its duct-firing range, so it will be unable the follow its dispatch signal from 15:50 and 16:10).

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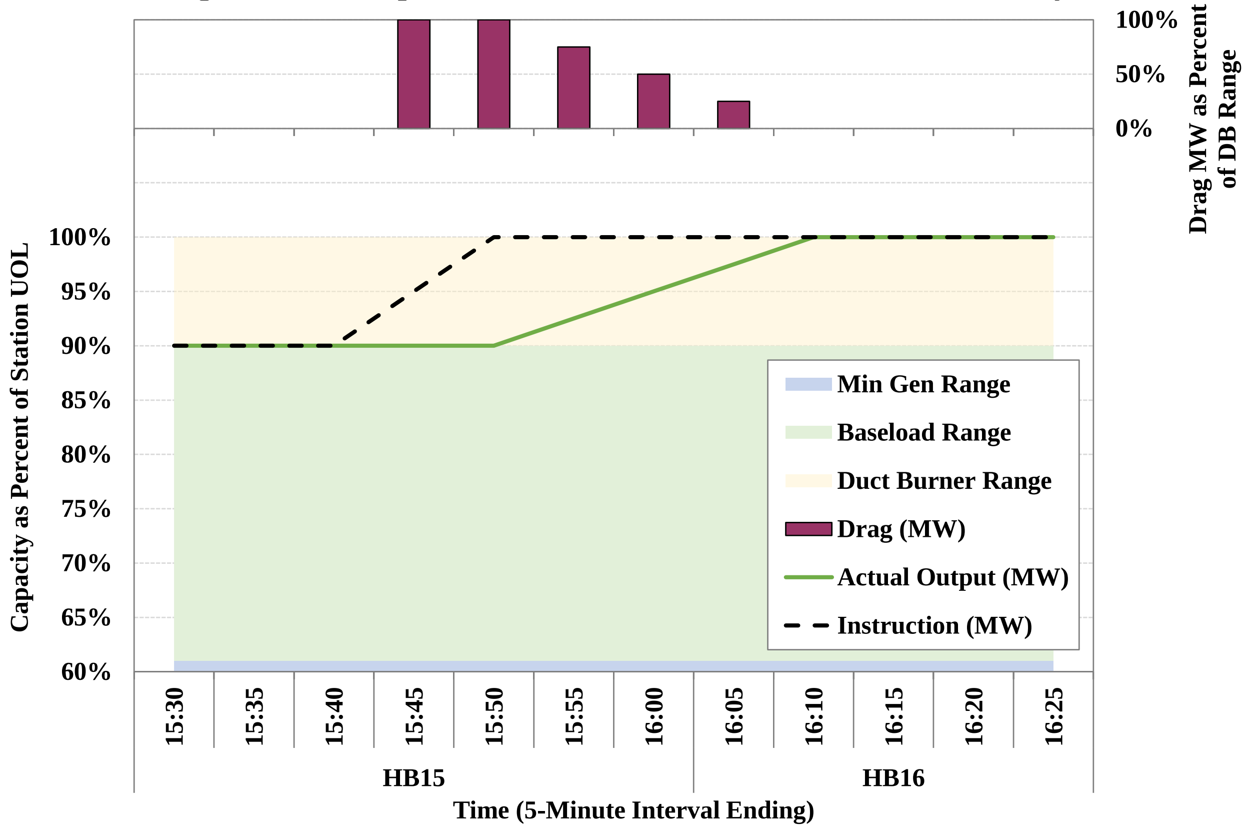
168 See Table A-6 in the Appendix.

169 Based on NYISO survey of participants with assets containing duct burners, less than 25 percent of this capacity has the ability to respond to AGC 6-second signals necessary for regulation movement while the duct-burners are operating.

170 Section 4.2.1.3.3 of the Market Services Tariff states, "Bids from Suppliers for Generators supplying Energy and Ancillary Services must specify a normal response rate and may provide up to three normal response rates provided the minimum normal response rate may be no less than one percent (1%) of the Generator's Operating Capacity per minute."

Figure 29: Example Performance of Duct Burner on Summer Day



Duct-firing capacity (on a combined cycle unit that is already online) has operational characteristics that are similar to a gas turbine peaker. It takes time to start-up, reach its maximum output level, and shut down. Gas turbine peakers are committed by RTC since they are not capable of following a 5-minute dispatch instruction. Similarly, it may be appropriate to commit and decommit duct-firing capacity using RTC ahead of the 5-minute dispatch.

We recommend NYISO consider alternative ways to schedule this capacity that takes into account the physical limitations of duct burners.[171] Ideally, this would: (a) economically commit and decommit duct-firing capacity using RTC as is done for gas turbine peaking units and (b) allow generators to submit offers that limit their regulation range to exclude the duct-firing capacity.

E. 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

[171] See Recommendation #2020-1 in Section XII.

LTE after a contingency.[172] 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 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 2020, nearly 70 percent (or $40 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 15, the additional transfer capability above LTE on New York City transmission facilities averaged: (a) 20 to 60 MW for 138 kV load-pockets; and (b) 180 to 330 MW for the 345 kV system during congested hours in 2020.[173]

Table 15: Modeled Limits vs Seasonal Limits for Select New York City N-1 Constraints
2020

Transmission Facility		Average Constraint Limit (MW)		
		N-1 Limit Used	Seasonal LTE	Seasonal STE
345 kV	Gowanus-Farragut	1064	834	1303
	Motthavn-Rainey	1050	833	1298
	Dunwodie-Motthavn	1101	857	1309
	Sprnbrk-W49th ST	1305	977	1541
	Farragu-E13th ST	1128	943	1347
	Goethals-Gowanus	962	748	1241
138 kV	Foxhills-Greenwd	311	247	376
	Gowanus-Greenwd	348	317	378
	Vernon-Greenwd	257	237	278

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 operating reserve units that can help satisfy transmission security criteria and settle with these units based on the

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

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

congestion component of the clearing price as is done with energy producers.[174] For similar reasons, the NYISO should also 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.

F. 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 redispatch of generation to maintain flows within appropriate levels. However, PAR-controlled lines have the potential to provide greater benefits than conventional AC transmission lines because they can be secured without generator redispatch. PAR-controlled lines are scheduled in two ways:

- "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 16 evaluates the consistency of the direction of power flows on non-optimized PAR-controlled lines and LBMP differences across these lines in 2020. 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 2 percent of hours in the day-ahead market in 2020. This is primarily because prices on Long Island were typically higher than those in New York City where the 901 and 903 lines connect at the Jamaica bus. 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.

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174 Recommendation #2016-1 in Section XII.

Table 16: Efficiency of Scheduling on Non-Optimized PAR Controlled Lines[175, 176]
2020

	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					-9	$3.44	52%	$1
New England to NYCA								
Sand Bar	-72	-$9.48	95%	$5	-2	-$9.30	55%	$0.4
PJM to NYCA								
Waldwick	41	$1.57	70%	$1	-23	$0.83	39%	-$3
Ramapo	247	$2.26	75%	$7	88	$1.87	61%	$4
Goethals	21	$2.63	74%	$1	91	$1.89	53%	$0.7
Long Island to NYC								
Lake Success	141	-$5.53	2%	-$7	-3	-$5.93	54%	$0.1
Valley Stream	83	-$7.66	2%	-$6	0	-$7.10	53%	-$0.1

The transfers across the 901 and 903 lines:

- Increased day-ahead production costs by $13 million in 2020 (and $10 million in 2019).
- Drove-up generation output from older less-fuel-efficient gas turbines and steam units without Selective Catalytic Reduction capability, leading to net increased emissions of 227 thousand tons of CO_2 and 472 tons of NOx pollution in non-attainment areas in 2020.
- Increased the consumption of gas from the Iroquois Zone 2 pipeline, which often trades at a significant premium over gas consumed from the Transco Zone 6 pipeline.

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.[177] Although this should benefit both parties in aggregate, it may financially harm one party. Hence, a new financial settlement mechanism is needed to ensure

175 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.

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

177 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.

that both parties benefit from the changes.[178] We recommend the NYISO work with the parties to this contract to explore changes that would allow the lines to be used more efficiently.[179]

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. 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 $2 million net *increase* in production costs in 2020, while the 5018 line and the Goethals line accounted for a net *reduction* of $11 million and $2 million, respectively. The next sub-section examines the operation of these lines under M2M coordination with PJM.

G. 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.[180] Figure 30 evaluates operations of these PARs under M2M with PJM in 2020 during periods of congestion between New York and PJM.[181]

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 surpluses frequently resulted from this operation on the Central-East interface as more flows are brought into New York to relieve congestion on the interface. However, these additional flows tend to aggravate congestion on the constraints in the West Zone, leading to balancing congestion shortfalls. The 115 kV constraints in the West Zone were not incorporated in the M2M PAR Coordination until December 2019, before which the net effect of this PAR operation was often inefficient, leading to net balancing congestion shortfalls. For example, we estimated that the M2M PARs resulted in a total of nearly $5 million of net shortfalls on the Central-East interface and West Zone constraints in 2019. However, this improved to a total of $0.6 million of net surpluses in 2020 following the inclusion of 115 kV West Zone constraints in the M2M JOA.

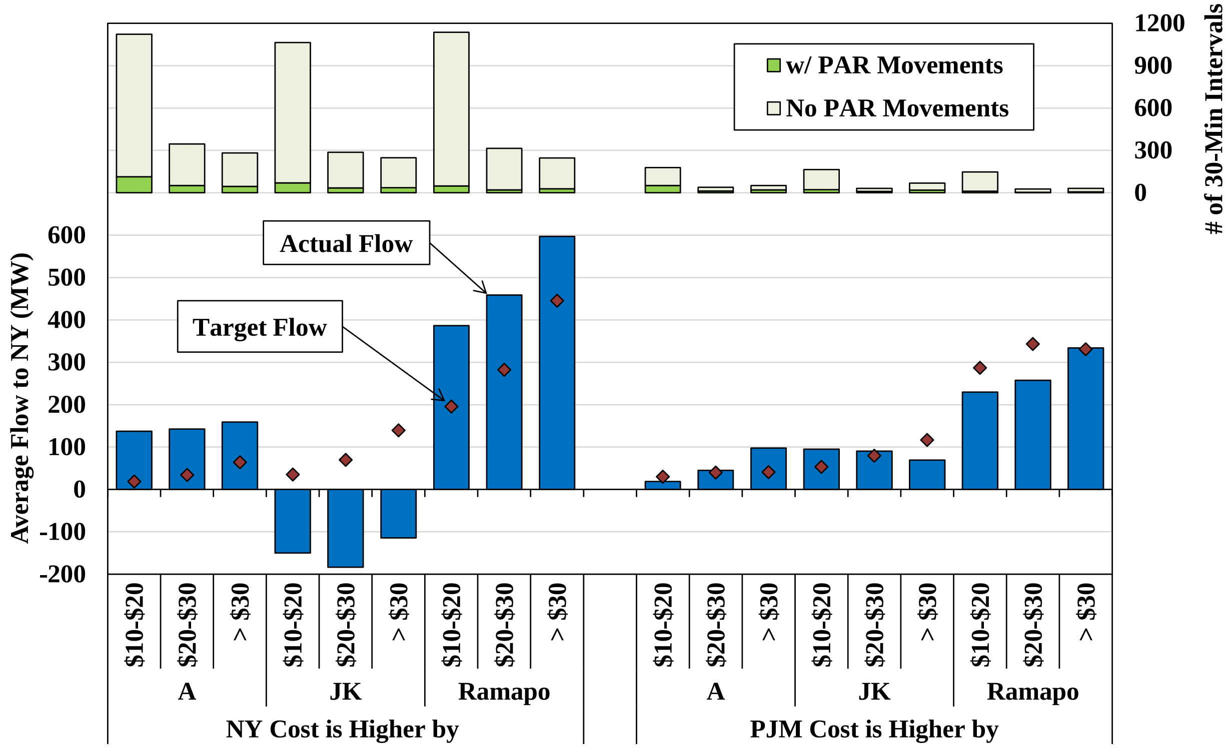
178 The proposed financial right would compensate ConEd for congestion management consistent with the revenue adequacy principles underlying nodal pricing, so the financial right holder would receive congestion revenues like other wholesale market transactions from the congestion revenue fund and no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

179 See Recommendation #2012-8 in Section XII.

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

181 See Appendix Section V.C for a detailed description of the figure and more information about the analysis.

Figure 30: NY-NJ PAR Operation Under M2M with PJM
During Congested Periods, 2020



Despite the improvement, there were still 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 2020 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 11 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 14 percent of overall price divergence in 2020.[182] This is partly because RTC has no information related to expected tap changes. Consequently, RTC may schedule 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

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

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.

H. Transient Real-Time Price Volatility

Volatile prices can be an efficient signal of the value of flexible resources, although unnecessary volatility imposes excessive costs on market participants, so it is important to identify the causes of volatility. In this subsection, we evaluate scheduling patterns that led to transient spikes in real-time prices for individual transmission constraints and the power-balance constraint (i.e., the requirement that supply equal demand) in 2020. The effects of transmission constraints are more localized, while the power-balance and reserve constraints affect prices throughout NYCA.

Transient price spikes occurred in roughly 4 percent of all intervals in 2020, less frequently than in 2019 partly because of lower load levels and improvements in congestion management in the West Zone. Nonetheless, these intervals were still 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 17 summarizes the most significant factors that contributed to real-time price volatility in 2020. 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.[183] For each group of constraints, the most significant categories and sub-categories are highlighted in purple and green, respectively.

Resources scheduled by RTC (e.g., external interchange and gas turbine shut-downs) were a key driver of transient price spikes for the power-balance constraint and most transmission constraints shown in the table. 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.

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

Table 17: Drivers of Transient Real-Time Price Volatility
2020

	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**		**309**		**2052**		**705**		**299**		**358**		**262**		**283**	
Number of Price Spikes	**184**		**2560**		**90**		**166**		**792**		**231**		**1302**		**219**	
Average Constraint Shadow Price	**$194**		**$480**		**$455**		**$370**		**$374**		**$437**		**$461**		**$521**	
Source of Increased Constraint Cost:	**(MW)**	**(%)**	**(MW)**	**(%)**	**(MW)**	**(%)**	**(MW)**	**(%)**	**(MW)**	**(%)**	**(MW)**	**(%)**	**(MW)**	**(%)**	**(MW)**	**(%)**
Scheduled By RTC	**170**	**64%**	**1**	**17%**	**73**	**49%**	**29**	**47%**	**7**	**50%**	**7**	**28%**	**2**	**33%**	**1**	**20%**
External Interchange	89	34%	1	17%	29	19%	13	21%	2	14%	4	16%	0	0%	1	20%
RTC Shutdown Resource	62	23%	0	0%	24	16%	14	23%	4	29%	2	8%	2	33%	0	0%
Self Scheduled Shutdown/Dispatch	19	7%	0	0%	20	13%	2	3%	1	7%	1	4%	0	0%	0	0%
Flow Change from Non-Modeled Factors	**4**	**2%**	**5**	**83%**	**61**	**41%**	**20**	**32%**	**6**	**43%**	**16**	**64%**	**4**	**67%**	**2**	**40%**
Loop Flows & Other Non-Market	2	1%	4	67%	22	15%	11	18%	5	36%	8	32%	3	50%	1	20%
Fixed Schedule PARs	0	0%	1	17%	35	23%	9	15%	0	0%	8	32%	1	17%	1	20%
Redispatch for Other Constraint (OOM)	2	1%	0	0%	4	3%	0	0%	1	7%	0	0%	0	0%	0	0%
Other Factors	**90**	**34%**	**0**	**0%**	**15**	**10%**	**13**	**21%**	**1**	**7%**	**2**	**8%**	**0**	**0%**	**2**	**40%**
Load	55	21%	0	0%	12	8%	7	11%	1	7%	2	8%	0	0%	1	20%
Generator Trip/Derate/Dragging	19	7%	0	0%	2	1%	6	10%	0	0%	0	0%	0	0%	0	0%
Wind	16	6%	0	0%	1	1%	0	0%	0	0%	0	0%	0	0%	1	20%
Total	**264**		**6**		**149**		**62**		**14**		**25**		**6**		**5**	
Redispatch for Other Constraint (RTD)	**89**		**0**		**17**		**2**		**1**		**2**		**7**		**6**	

Loop flows and other non-market factors were the primary driver of transient price spikes 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. However, the frequency of transient price spikes in the West Zone fell 63 percent from 2019 largely because of: (a) improvements in the M2M process that incorporated West Zone 115 kV constraints; and (b) the use of more conservative assumptions in RTC regarding loop flows.

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.[184] The PARs are not adjusted frequently in response to variations in generation, load, interchange, and other PAR adjustments.[185] 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.

184 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.

185 Section X.G 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.

Among other factors, variations in load forecast had significant impact on the power balance constraint. Load variation became more impactful in 2020 as a result of larger load forecast errors during the COVID-19 pandemic. Changes in wind forecast were a key driver of transient price spikes on constraints from North to Central New York where a large amount of wind generating capacity is located.

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

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: [186]

- 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). 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. This has been an improvement, but we continue to recommend the NYISO develop the capability to put in adjustments that vary according to the level of LEC at the time RTC initializes.
- 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.

I. 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. There are several types of supplemental commitment: (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 occurs to meet a local reliability need within the economic commitment within the day-ahead market; (c) Supplemental Resource Evaluation ("SRE") commitment that occurs after the day-ahead market closes; and (d) Forecast Pass Commitment ("FCT") occurs in the day-ahead market after the economic pass if it does not schedule enough physical resources to satisfy forecasted load and reserve requirements.

186 See Recommendation #2014-9 in Section XII.

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. These OOM actions are a sign of market inefficiency for several reasons. First, OOM actions highlight a gap in the market design or market processes that necessitates out-of-market intervention to obtain a reliability service that is not procured through the market. Second, they 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.

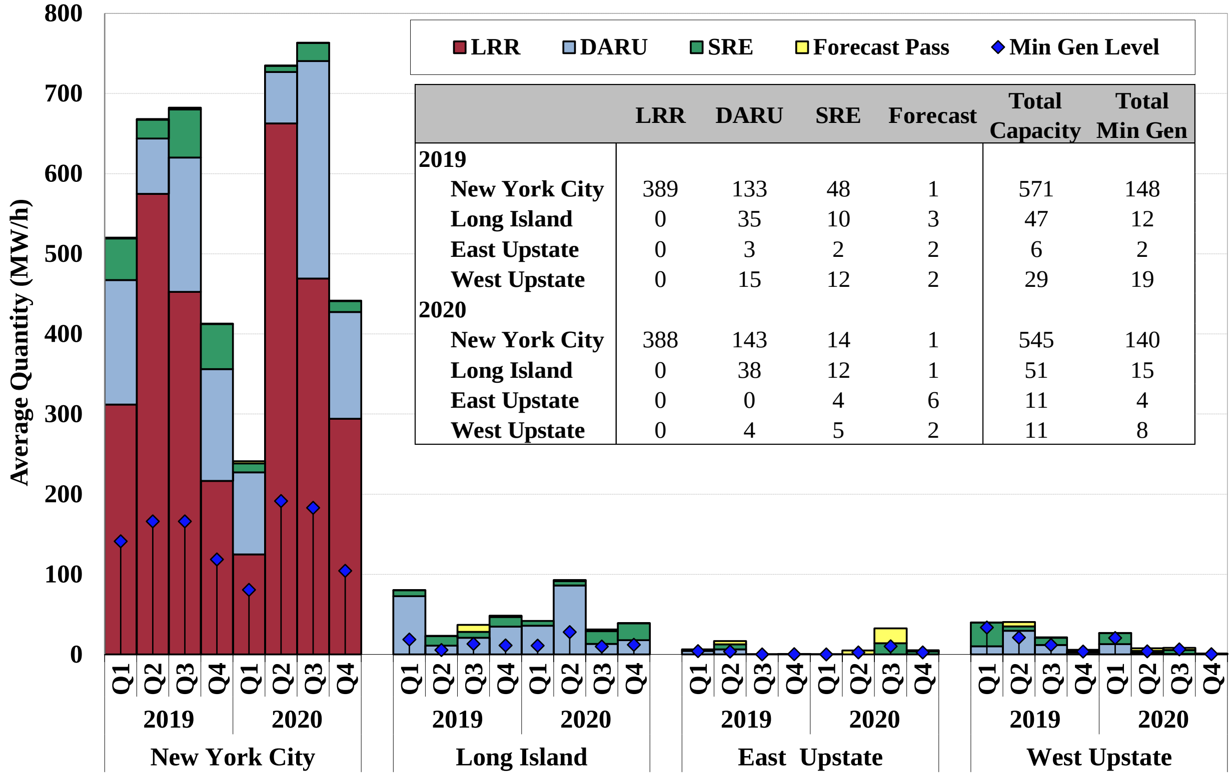
Supplemental Commitment in New York State

Figure 31 summarizes the quantities of four types of reliability commitment (i.e., DARU, LRR, SRE, and Forecast Pass) by region in 2019 and 2020.[187] Roughly 620 MW of capacity was committed on average for reliability in 2020, down modestly from 2019. New York City accounted for 88 percent of total reliability commitment in 2020 and saw a modest reduction from 2019. The reduction in New York City occurred primarily in the first quarter, which resulted from procedural changes that reduced supplemental commitments at the Arthur Kill plant when it was not actually needed for local reliability.

Despite this reduction, we identified two additional types of excess reliability commitments in New York City, which depress prices, generate uplift, and lead to excess production costs. First, the LRR pass was using a single daily capacity requirement in all 24 hours for most load pockets, leading to unnecessary commitment in off-peak hours.[188] We estimated that, if hourly capacity requirements were used, LRR Commitments in 358 hours across 63 days would have been avoided. The NYISO began to apply these capacity requirements on an hourly (rather than daily) basis beginning July 30 in the day-ahead market, which has reduced the amount of LRR commitments in off-peak hours.

187 See Section V.o in the Appendix for a description of the figure.
188 See Figure A-99 in the Appendix for more information about this analysis.

Figure 31: Supplemental Commitment for Reliability in New York
By Category and Region, 2019-2020



	LRR	DARU	SRE	Forecast	Total Capacity	Total Min Gen
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
2020						
New York City	388	143	14	1	545	140
Long Island	0	38	12	1	51	15
East Upstate	0	0	4	6	11	4
West Upstate	0	4	5	2	11	8

The second driver of excess reliability commitments in New York City was related to the NOx Bubble requirements.[189] Specifically, we found that a steam turbine was committed solely to satisfy the NOx rule on 68 days during the Ozone season of 2020 and these NOx-only steam turbine commitments could have been avoided on 57 days if the market software was allowed to consider whether the GTs were actually needed for reliability (before committing the associated steam turbine). Although these NOx Bubble requirements will be phased out with the existing air permits for older New York City peaking units as they retire or discontinue operations in 2023 and 2025, it would be beneficial to develop ways to avoid these commitments when they are not necessary for local reliability. This would require the New York State Reliability Council to revise Application of Reliability Rule #37.

Reliability commitments in other areas were relatively infrequent in 2020, most of which were DARU commitments on Long Island for local reliability and congestion management on the 69 kV network.

Forecast pass commitments, while infrequent, rose modestly from 2019. Our evaluation showed that physical energy scheduled to serve bid-in load was often lower than forecasted load in the

189 See Figure A-100 in the Appendix for more information about this analysis.

day-ahead market.[190] The amount of shortfalls averaged nearly 1 GW per hour, however, forecast-pass commitment exceeded 1000 MWh only on 13 days because surplus capacity from physical resources (committed in the economic pass) was sufficient on most days. Thus, the NYISO routinely holds large amounts of operating reserves on capacity that is not scheduled (or compensated) in the day-ahead market. It would be beneficial to consider modeling this reliability need as a reserve requirement and to procure and price the required amount of reserves through the market as part of the effort to set operating reserve requirements dynamically. Specifically, we recommend that the NYISO procure sufficient 30-minute reserves in the day-ahead market to cover the statewide 30-minute reserve requirement plus the differential between forecasted load and the energy scheduled from physical resources (i.e., not virtual supply).[191]

Price Effects of Modeling N-1-1 Reserve Constraints in New York City

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.

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 2020 if the NYISO were to devise a day-ahead market reserve requirement.[192] Table 18 summarizes the results of this evaluation based on market results for four locations in New York City: the 345kV network outside of Staten Island, the Astoria West/Queensbridge load pocket, the Vernon location on the 138 kV network, and the Freshkills load pocket on Staten Island.

190 See Figure A-97 in the Appendix for more information about this analysis.

191 See Recommendation #2015-16.

192 Section V.o in the Appendix describes the methodology of our estimation.

Table 18: Day-ahead Reserve Price Estimates
Selected NYC Load Pockets, 2020

Area	Average Marginal Commitment Cost ($/MWh)
NYC 345 kV System	$1.99
Selected 138 kV Load Pockets:	
Astoria West/Queensbridge	$3.26
Vernon	$2.61
Freshkills	$2.95

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 $1.99 per MWh in most areas to as much as $3.26 per MWh in the Astoria West/Queensbridge load pocket in 2020. 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.[193] 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 18. This pricing enhancement would have had a large impact, increasing net revenues by $19 per kW-year for the demand curve unit in New York City.[194] The Reserve Enhancements for Constrained Areas project is currently underway at NYISO, which will explore ways to model a dynamic allocation of reserves to satisfy load pocket requirements while satisfying statewide and regional reserve requirements.[195] This effort has potential to greatly improve the pricing of energy and reserves in NYC load pockets and other constrained areas in the system.

Out of Merit Dispatch

Table 19 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.[196]

193 See Recommendation #2017-1 in Section XII.

194 See analysis in Section VII.D.

195 See the presentation " Reserve Enhancements for Constrained Areas", by Pallavi Jain at ICAPWG/MIWG meeting on April 6, 2021.

196 Figure A-101 in the Appendix provides additional detail in 2019 and 2020 for each region.

Table 19: Frequency of Out-of-Merit Dispatch
By Region, 2019-2020

Region	OOM Station-Hours		
	2019	2020	% Change
West Upstate	241	115	-52%
East Upstate	2295	107	-95%
New York City	513	143	-72%
Long Island	2703	4354	61%
Total	**5752**	**4719**	**-18%**

The quantity of OOM dispatch fell 18 percent from 2019 to 2020. The reduction was driven primarily by the decrease in the East Upstate region, where OOM actions to manage post-contingency flow on the Albany-Greenbush 115 kV facility were greatly reduced following transmission upgrades in mid-2019. In western New York, OOM dispatch has been falling as more 115 kV facilities that were previously managed by OOM actions have been gradually incorporated into the market models since 2018.

However, the frequency of OOM dispatch on Long Island rose 61 percent from 2019 to 2020 and accounted for 92 percent of all OOM actions statewide in 2020. 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. The need for OOM actions increased in the summer of 2020 as a result of: (a) higher load levels driven by warmer weather and higher residential load during the COVID-19 pandemic; and (b) lengthy transmission outages of the Cross Sound Cable and the Neptune interface. These OOM actions have been increasing in recent years, resulting in inefficient pricing and dispatch as well as uplift charges. To further reduce OOM actions and improve market efficiency in scheduling and pricing, 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.[197] On April 13, 2021, the NYISO began securing two 69 kV circuits in the market software that are among the most significant drivers of OOM dispatch and PAR operations that affect flows on the 138 kV system.

J. Guarantee Payment Uplift Charges

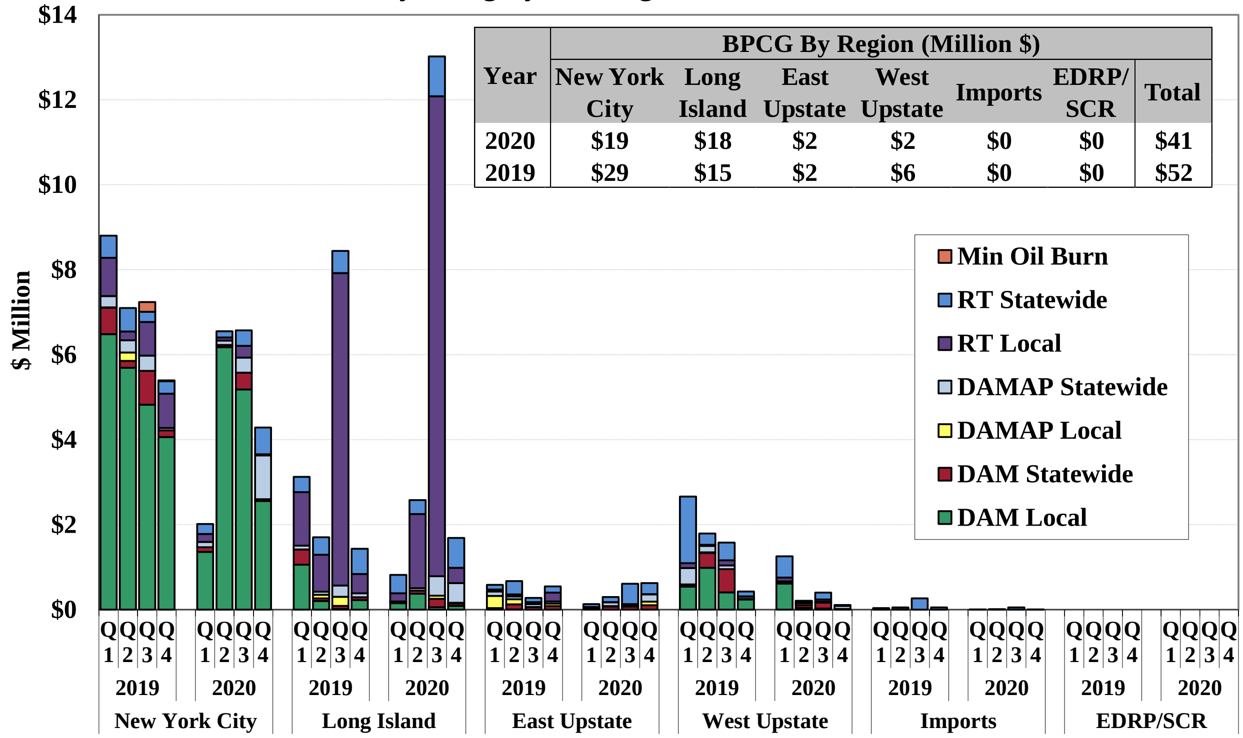
The NYISO recovers the payments it makes to certain market participants that are not recouped from LBMP and other market revenues through uplift charges. It is important to minimize uplift charges because they are difficult to hedge and do not provide transparent economic signals to market participants and potential investors. When markets reflect reliability requirements and system conditions, uplift charges should be relatively low.

197 See Recommendation #2018-1.

Figure 32 shows guarantee payment uplift for four local reliability categories and three non-local reliability categories in 2019 and 2020 on a quarterly basis.[198] The figure shows that guarantee payment uplift totaled $41 million in 2020, down 21 percent from 2019. The decrease was driven primarily by lower gas prices, which decreased the commitment cost of gas-fired units.

Figure 32: Uplift Costs from Guarantee Payments in New York

By Category and Region, 2019 – 2020



Year	BPCG By Region (Million $)						
	New York City	Long Island	East Upstate	West Upstate	Imports	EDRP/ SCR	Total
2020	$19	$18	$2	$2	$0	$0	$41
2019	$29	$15	$2	$6	$0	$0	$52

New York City accounted for $19 million (or 46 percent) of BPCG in 2020, down 34 percent from 2019. Over $15 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. [199]

In spite of the reduction in other regions, Long Island saw an increase in BPCG uplift from $15 million in 2019 to $18 million in 2020. The increase occurred primarily in the category of real-time local BPCG uplift as high-cost peaking resources were OOMed more frequently in the summer months to manage 69 kV congestion and local voltage needs (for the reasons discussed earlier). Nearly $14 million (or 78 percent) of BPCG uplift was paid in 2020 for this purpose. We have recommended the NYISO consider modeling certain 69 kV constraints and local

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198 See Figure A-102 and Figure A-103 in the Appendix for a more detailed description of this analysis.

199 See Recommendation #2017-1.

voltage requirements on Long Island in the day-ahead and real-time markets.[200] Our estimates have shown significant impact on LBMPs 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.[201]

200 See Recommendation #2018-1.

201 See Section V.B for this analysis.

XI. DEMAND RESPONSE PROGRAMS

Participation by demand response in the market is beneficial for many reasons. Demand response contributes to reliable system operations, long-term resource adequacy, lower production costs, decreased price volatility, and reduced supplier market power. Even modest reductions in consumption by end users during high-price periods can significantly reduce the costs of committing and dispatching generation to satisfy the needs of the system. These benefits underscore the value of designing wholesale markets that provide transparent economic signals and market processes that facilitate demand response. 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.

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:

- Meter Service Entity ("MSE") for DER – The MSE rules went into effect in May 2020, which authorize third party metering that provides greater flexibility to consumers and retail load serving entities for demand side participation.
- Dual Participation ("DP") – The DP rules went into effect in May 2020, which allow resources that provide wholesale market services to also provide retail market services.
- DER Participation Model – Scheduled for software development in 2021 and deployment in 2022. – 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.

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 shortage. Currently, nearly all of the 1,199 MW of demand response resources registered in New York are reliability demand response resources.[202]

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[202] In addition, there are demand response programs that are administered by local TOs.

Special Case Resources Program

The SCR program is the most significant demand response program operated by the NYISO with roughly 1,198 MW of resources participating in 2020. 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 2020 Capability Period, SCRs made contributions to resource adequacy by satisfying:

- An average of 4.6 percent of the UCAP requirement for New York City;
- An average of 3.9 percent of the UCAP requirement for the G-J Locality;
- An average of 0.8 percent of the UCAP requirement for Long Island; and
- An average of 3.3 percent of the UCAP requirement for NYCA.

However, the registered quantity of reliability program resources fell by roughly 50 percent from 2010 to 2020 primarily because of enhancements to auditing and baseline methodologies for SCRs since 2011 (registered quantity did not change significantly each year from 2013 to 2020). 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, two 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 50 MW of 10-minute spinning reserves in 2020, satisfying more than 8 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.

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 2020, the

NYISO did not activate reliability demand response resources, therefore, the performance of demand response calls is not evaluated in this report.[203]

However, The TDRP was activated on five days in July in response to Transmission Owner requests. These responses were voluntary and the scarcity pricing was not applicable. In addition, demand response resources in local utility programs were activated on 21 days in 2020. The amount of these deployments exceeded 100 MW on eight days and approached nearly 550 MW on one day, roughly half of which was activated for peak-shaving and distribution system security in New York City and the other half for peak-shaving outside New York City. Our analysis shows that these deployments helped avoid a brief NYCA capacity deficiency on just two days, [204] and the economics of the energy market did not indicate a need for peak load reduction on most of the other days with utility.[205]

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 or unnecessary out-of-market actions 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 processes.

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

204 See our analysis in Section V.I in the Appendix for more details.

205 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.

XII. Recommendations

Our analysis in this report indicates that the NYISO electricity markets performed well in 2020, although we recommend additional enhancements to improve market performance. Twenty-five 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 2019 SOM Report, but Recommendations #2020-1 to #2020-3 are new in this report. The following tables summarize our current recommendations and the status of any ongoing or recently completed NYISO market design projects that address them.

High Priority Recommendations

<table>
<tr><th>Number</th><th>Section</th><th>Recommendation</th><th>Current Effort</th></tr>
<tr><td colspan="4">Energy Market Enhancements - Pricing and Performance Incentives</td></tr>
<tr><td>2017-1</td><td>VIII.C, X.I</td><td>Model local reserve requirements in New York City load pockets.</td><td rowspan="3">Reserve Enhancements for Constrained Areas project to complete a study of these issues in 2021.</td></tr>
<tr><td>2016-1</td><td>VIII.C, X.E</td><td>Consider rules for efficient pricing and settlement when operating reserve providers provide congestion relief.</td></tr>
<tr><td>2015-16</td><td>X.A, VIII.C</td><td>Dynamically adjust operating reserve requirements to account for factors that increase or decrease the amount of reserves that must be held on internal resources.</td></tr>
<tr><td>2017-2</td><td>VIII.C, X.A</td><td>Modify operating reserve demand curves to improve shortage pricing and ensure NYISO reliability.</td><td>Partially addressed by tariff filing under Ancillary Services Shortage Pricing project in 2021.</td></tr>
<tr><td colspan="4">Capacity Market – Market Power Mitigation Measures</td></tr>
<tr><td>2019-3</td><td>III.C, IX.D</td><td>Modify the Part A test to allow public policy resources to obtain exemptions when it would not result in price suppression below competitive levels.</td><td>Tariff filing in 2020 rejected by FERC; pending judicial review.</td></tr>
<tr><td colspan="4">Capacity Market – Design Enhancements</td></tr>
<tr><td>2020-3</td><td>VII.E</td><td>Revise the capacity accreditation rules to compensate resources in accordance with their marginal reliability value.</td><td></td></tr>
<tr><td>2013-1c</td><td>VII.D</td><td>Implement locational marginal pricing of capacity (“C-LMP”) that minimizes the cost of satisfying planning requirements.</td><td></td></tr>
</table>

Other Recommendations

Number	Section	Recommendation	Current Effort
Energy Market Enhancements - Pricing and Performance Incentives			
2019-1	Appx. VII.D	Set day-ahead and real-time reserve clearing prices considering reserve constraints for Long Island.	
2018-1	V.B, X.I	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.	NYISO began modeling certain constraints beginning in 2021.
2015-9	VI.C	Eliminate transaction fees for CTS transactions at the PJM-NYISO border.	
2015-17	X.A	Utilize constraint-specific graduated transmission demand curves to set constraint shadow prices during transmission shortages.	Constraint Specific Shortage Pricing project targets market design complete in 2021.
Energy Market Enhancements – Market Power Mitigation Measures			
2017-3		Modify mitigation rules to address deficiencies in the current rule related to uneconomic over-production.	Uneconomic Overproduction project ongoing in 2021.
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			
2020-1	X.D	Consider enhancements to the scheduling of duct-firing capacity in the real-time market that more appropriately reflects its operational characteristics.	
2020-2	X.A	Eliminate offline fast-start pricing from the real-time dispatch model.	
2019-2		Adjust offer/bid floor from negative $1000/MWh to negative $150/MWh.	
2014-9	VI.C, IX.H	Consider enhancing modeling of loop flows and flows over PAR-controlled lines to reflect the effects of expected variations more accurately.	
2012-8	X.F	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.C, X.H	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			
2018-3	III.C, IX.D	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.	Included in tariff filing to address Rec. 2019-3.

Number	Section	Recommendation	Current Effort
2013-2d	III.C, IX.D	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.H	Modify translation of the annual revenue requirement for the demand curve unit into monthly demand curves that consider reliability value.	
2019-5	VII.H	Translate demand curve reference point from ICAP to UCAP terms based on the demand curve unit technology.	
2012-1c	VII.F	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.G	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 over the long term.[206]

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. (Current Effort)

[206] See discussion in Section VII.D of the Appendix. See 2022 Project Candidate: *Long Island Reserve Constraint Pricing*.

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. Efficient price signals for resources that help manage these constraints could support retention of existing units or investment in new capacity (including energy storage) that would help integrate intermittent renewable generation and reduce the need for regulated transmission solutions.

Securing these constraints in the day-ahead and real-time markets requires significant effort, including additional coordination with the local Transmission Owner.[207] Hence, we recommend that NYISO prioritize modeling constraints that require the most frequent out-of-market actions, including:

- Surrogate constraints so that generation is scheduled to satisfy transient voltage recovery (TVR) criteria for the East End of Long Island and priced accordingly; and
- Selected 69 kV circuits that are frequently secured through out-of-market actions.

On April 13, 2021, the NYISO began securing two 69 kV circuits in the market software that are among the most significant drivers of OOM dispatch and PAR operations that affect flows on the 138 kV system.[208] This should significantly improve the efficiency of prices and schedules in that portion of Long Island.

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-1-1-0 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 and longer-term incentives for new investment that

207 See discussion in Sections V.B and Section VII.D of the Appendix. This project requires operational changes but no tariff changes, so this project is not listed as a 2022 Project Candidate.

208 The following two 69 kV constraints are planned for the April 2021 software deployment: the Brentwood-Pilgrim line and the Elwood-Pulaski line.

can satisfy the local requirements.[209] Hence, we recommend the NYISO consider implementing local reserve requirements in the New York City load pockets.

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-1-1-0 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 reserve 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.

ConEd recently updated its Local Transmission Plan to include three new PAR-controlled lines to replace retiring peakers in the Astoria East/Corona and Greenwood/Fox Hills load pockets.[210] The construction of transmission and exit of peaking generation will shift the location of reserve-constraint areas from relatively localized load pockets to larger load pockets within New York City. Furthermore, the configuration of reserve-constrained load pockets will shift as offshore wind resources are interconnected in New York City. Overall, these changes will generally increase the need to commit and/or redispatch generation to provide operating reserves in New York City over the next five to ten years.

The lack of comprehensive local reserve modeling for New York City in the market software leads to out-of-market actions and insufficient incentives for new investment under current market conditions. However, this recommendation is high priority partly because changes in the New York City resource mix will tend to exacerbate these issues.

2017-2: Modify operating reserve demand curves to improve shortage pricing and ensure NYISO reliability. (Current Effort, High Priority)

The NYISO has historically benefitted from significant net imports during reserve shortages and other extreme scarcity conditions. However, recently implemented PFP ("Pay For Performance") rules in ISO New England and PJM result in much higher incremental

209 See discussion in Sections X.I and VIII.C. For current effort, see the 2021 Project *Reserve Enhancements for Constrained Areas*, which would perform a study of a comprehensive market solution inclusive of the more limited *More Granular Operating Reserves* project considered in previous years.

210 See ConEdison, *CECONY's Updated Local Transmission Plan*, presented to Electric System Planning Working Group on January 25, 2021.

compensation for energy and reserves 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. The values of operating reserve demand curve steps should be targeted 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.[211]

In 2021, the NYISO filed tariff changes with FERC that would revise the structure of reserve demand curves. The proposed changes would increase the quantity of NYCA 30-minute reserves that are assigned the current maximum shadow price of $750/MWh and add demand curve steps that reflect the historical costs of operator actions taken to maintain reliability.[212] These changes would improve the efficiency of the reserve demand curves by reducing the need for out-of-market actions during reserve shortages. However, the proposed changes do not alter the values of the maximum shadow prices that occur during system-wide reserve shortages or emergencies. The NYISO should continue to evaluate higher shortage pricing values, including higher maximum values during systemwide scarcity.

This recommendation is high priority because the increasingly complex power grid will require strong incentives for all resources to be responsive to system needs. Shortage pricing values that are aligned with the value-of-lost-load and with scarcity pricing in neighboring systems would induce internal and external resources to maximize their availability during scarcity conditions in a more flexible and efficient manner than relying on operator actions. Incentives for flexibility and reliability are likely to be increasingly important as intermittent renewables enter the system and net load forecast uncertainty increases. The costs of increasing operating reserve demand curves would be offset by a corresponding reduction in capacity market demand curves.

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

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211 See discussion in Sections X.A and VIII.C.

212 For current effort, see FERC docket ER21-1018 and 2020 Project: *Ancillary Services Shortage Pricing*.

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. We describe a conceptual approach to providing efficient compensation in this report.[213] 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 is 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. This will become more important as new intermittent generation is interconnected to the New York City transmission system in the coming years because this will lead to additional variability in congestion patterns.

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

The efficiency benefits of the Coordinated Transaction Scheduling (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. We estimate that the collection of export fees from CTS transactions was just $0.6 million in 2020 because the high export fees were usually higher than the expected profits from exporting to PJM. Thus, a lower export fee could result in an overall higher collection of fees because it would allow CTS transactions to be profitable under a wider range of conditions. It is unlikely that CTS with PJM will function effectively as long as transaction fees and uplift charges are large relative to the expected value of spreads between markets. Hence, we recommend eliminating transaction fees and uplift charges between the PJM and NYISO.[214]

213 See discussion in Section X.E and VIII.C. See 2021 Project: *Reserve Enhancements for Constrained Areas*.

214 See discussion in Section VI.C. See 2022 Project Candidate: *Eliminate Fees for CTS Transactions with PJM*.

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. (Current Effort, 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. This report outlines how local reserve requirements and associated price signals could be determined dynamically based on load, transmission capability, and online generation. Section V.L of the Appendix describes a mathematical modeling approach to determine dynamic reserve requirements. We identify 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 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 recommendations 2016-1 and/or 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. Our proposed framework for determining dynamic reserves would also contribute to more efficient outcomes by appropriately discounting the value of units that contribute to larger contingencies when they are committed to satisfy local reliability requirements.

Hence, we recommend that the NYISO modify the market software to optimize the quantity of reserves procured for each of these requirements.[215] This could also provide an opportunity for operators to adjust individual reserve requirements based on system conditions, which would provide a market-based alternative to the current practice of committing generation out-of-market after the day-ahead market to make additional reserve capability available. This would provide better incentives for investment in flexible resources as the need for flexibility increases in the future.

This recommendation is a high priority because it 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.

The NYISO has advanced a project which would partially implement this recommendation by aligning GTDCs with the actual constraint reliability margin (CRM) of specific transmission

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215 See discussion in Section X.A and VIII.C. See Section V.L of the Appendix for a potential mathematical modeling approach. See 2021 Project: *Reserve Enhancements for Constrained Areas*.

facilities.[216] We support the NYISO's project, and recommend that it also consider evaluating whether the use of GTDC pricing values that vary by transmission facility would provide more efficient real-time pricing signals.

Energy Market Enhancements – Market Power Mitigation Measures

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

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.[217] NYISO proposed rule changes that would address this recommendation in 2021.[218]

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.[219]

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216 See discussion in Section X.A. See 2021 Project: *Constraint Specific Transmission Shortage Pricing*. The 2021 Project aims to present a Market Design Complete to stakeholders in late 2021.

217 See discussion in Section IX.A of our 2019 State of the NYISO Market report.

218 For current effort, see NYISO presentation *Uneconomic Overproduction*, presented to Market Issues Working Group on March 29, 2021.

219 See discussion in Section III.B.

Energy Market Enhancements – Real-Time Market Operations

2020-1: Consider enhancements to the scheduling of duct-firing capacity in the real-time market that more appropriately reflects its operational characteristics.

Generators with duct firing capacity are able to offer it into NYISO's real-time market as a portion of the dispatchable range of the generator. However, duct-firing capacity is generally not capable of following a 5-minute dispatch signal. The process of starting-up and shutting-down duct burners is similar to the start-up and shut-down of a fast start peaking unit. For this reason, many generators with duct-firing capability do not offer it into the real-time market, while others "self-schedule" this capacity inflexibly. There is approximately 760 MW of duct-firing capacity in the NYCA, so this enhanced scheduling capability could significantly increase the availability of operating reserves, which will become more valuable as older peaking units retire over the next four years.[220] We recommend NYISO the potential benefits and costs of developing the capability to commit and de-commit duct-firing capacity in the real-time market as it would do with an offline peaking unit.

2020-2: Eliminate offline fast-start pricing from the real-time dispatch model.

NYISO's real-time market runs a dispatch model that updates prices and generator schedules every five minutes. Currently, the dispatch model treats 10-minute gas turbines (i.e., units capable of starting up in ten minutes) as if they can follow a 5-minute signal. However, since 10-minute gas turbines are unable to respond in five minutes, the units routinely receive schedules they are incapable of following. This leads to periods of under-generation, inconsistencies between scheduled transmission flows and actual flows, and inefficient prices that do not reflect the balance of supply and demand.[221] We recommend that NYISO eliminate the feature which is known as offline fast-start pricing.

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.[222]

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220 See discussion in Section X.D.

221 See discussion in Section X.A.

222 See discussion in Section V.A of our 2019 State of the NYISO Market report. See 2022 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). In November 2019, NYISO began to assume the loop flows equal to the greater of 100 MW or the last telemetered value in the clockwise direction, which was an improvement over the previous assumption.[223] However, additional refinements would significantly reduce inconsistencies between RTC and RTD pricing and scheduling outcomes.

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.[224] 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 2020, these lines were both scheduled in the day-ahead market in the inefficient direction (i.e., from the high-priced area to the low-priced area) 2 percent of the time. We estimate that their operation increased production costs by an $13 million, carbon dioxide emissions by 227 thousand tons, and nitrous oxide emissions by an 472 tons.[225]

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223 See discussion in Section V.E in the Appendix of our 2019 State of the NYISO Market report.

224 See discussion in Sections VI.C and X.H. See 2022 Project Candidate: *Enhanced PAR Modeling*.

225 See discussion in Section X.F. See 2022 Project Candidate: *Long Island PAR Optimization & Financial Rights*.

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.H of the Appendix.

2012-13: Adjust look ahead evaluations of RTD and RTC to be more consistent with the timing of external transaction ramp and gas turbine commitment.

Differences is the ramp assumptions for units that are in the process of shutting-down and changes in external transactions schedules between RTC and RTD are a principal driver the price volatility evaluated above. To reduce unnecessary price volatility that results from ramping external interchange and shutting-down generation, we recommend the NYISO consider one or more of the following enhancements to improve the modeling of ramp in RTC and RTD: [226]

- 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 be important as NYISO integrates more intermittent renewable generation in the coming years.

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[226] See discussion in Sections VI.C and X.H. See 2022 Project Candidate: *Review of Real-Time Market Structure*.

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 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.

In 2020, the NYISO worked with stakeholders to develop a set of enhancements to the Part A Test, which exempts new entrants from BSM if surplus capacity is lower than a certain threshold. The proposed Part A enhancements would give priority to Public Policy Resources ("PPRs") in the testing order, use more realistic forecast periods for each technology (facilitating exemptions for resources with fast development timelines if there are expected supply needs in the short term), and provide multiple opportunities to receive an exemption over a three-year forecast period. These Part A enhancements would help to facilitate exemption of state-sponsored resources without compromising protections against unrestricted price manipulation. The NYISO's proposal was denied by FERC and is currently under judicial review by the United States Court of Appeals for the District of Columbia Circuit. We continue to support the NYISO's efforts to update the BSM rules and its Part A Test proposal in particular.[227]

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. (Current Effort)

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

227 See discussion in Section III.C and IX.D.

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.[228] [229]

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. We recommend the NYISO modify the BSM assumptions to allow the forecasted prices and project interconnection costs to be reasonably consistent with expectations.[230] Additionally, we recommend modifications to the calculation of the maximum quantity of Renewable Entry Exemptions to be more consistent with resources' market impacts.

Capacity Market – Design Enhancements

2020-3: Revise the capacity accreditation rules to compensate resources in accordance with their marginal reliability value. (High Priority)

Capacity markets exist to provide efficient incentives for attracting resources needed to satisfy the planning reliability requirements of the system. Thus, individual capacity suppliers should be compensated in accordance with the incremental reliability value they provide to the system. In an efficient capacity market, two resources that provide the same incremental reliability value should receive the same compensation.

The incremental reliability value of individual resources should vary according to their availability during certain critical hours when capacity margins are tightest. The current capacity rules do not accurately reflect the marginal reliability value of certain classes of resources, including energy storage and other duration-limited resources, intermittent generation, conventional generators with low availability and long start-up lead times, special case (demand response) resources, and large supply contingency resources. In addition, the EFORd-calculation methodology leads to a downward bias in the EFORd values of some generators.[231] Without enhancements to the current capacity accreditation rules, these deficiencies are likely to become more severe as the resource mix evolves over the next two decades.

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228 See discussion in Section III.C and IX.D.

229 We expect this recommendation to be addressed if the NYISO's Part A Enhancement filing is accepted – see discussion under Recommendation 2019-3.

230 See discussion in Section III.C and IX.D. See 2022 Project Candidate: *Enhanced BSM Forecasts Assumptions*.

231 See discussion in Section VII.E. See 2022 Project Candidate: *Improving Capacity Accreditation*.

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).[232] If gas-to-electric switching and other electrification efforts cause New York to transition from a summer-peaking system to a winter-peaking system, this recommendation would help ensure that capacity market incentives are focused during peak demand conditions.

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

The capacity market demand curves are currently set artificially high due to the use of incorrect forced outage rates. Correcting this issue is a low-effort project requiring only changes to a small number of parameters used to determine the demand curves.

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. Hence, the UCAP Net CONE used in the demand curves is higher than the actual UCAP Net CONE of the demand curve unit. This inconsistency will become more pronounced as additional intermittent resources are added to the system, causing regional average derating factors to increase. We recommend the NYISO

232 See discussion in Section VII.H. See 2022 Project Candidate: *Monthly Demand Curves.*

utilize the estimated forced outage rate of the demand curve unit technology to perform the ICAP to UCAP translation. [233]

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.[234] 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

[233] See discussion in Section VII.H. See 2022 Project Candidate: *Demand Curve Translation Enhancement.*

[234] See discussion in Section VII.D. See 2022 Project Candidate: *Locational Marginal Pricing of Capacity*.

(b) reduce barriers to entry that sometimes occur under the existing rules when a new generation project is required to make uneconomic transmission upgrades.[235]

Enhance Planning Processes

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

The growth of renewable generation in the coming years will drive the need for transmission investments. It is important that NYISO's economic and public policy transmission planning processes accurately evaluate project benefits so that the most cost-effective projects move forward. Significant changes to these processes' assumptions and procedures are needed to ensure that they are effective.

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, several assumptions in the public policy planning process may not ensure that the most cost-effective projects are selected. Recommended improvements to both processes include:

- Valuation of the transmission project's capacity benefits;
- Base case inclusion rules that more realistically reflect incoming new generation and policy requirements;
- Modeling of how the project would affect the resource mix; and
- Use of a 20-year period to evaluate projects' benefit-cost ratio instead of the current overly restrictive 10-year period in the economic planning process.

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 and should be revised. 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.[236]

NYISO filed tariff revisions in February 2021 that would make changes to aspects of the economic planning process, focused on making the initial system assessment phase more flexible and informative.[237] We support these improvements, and encourage NYISO to pursue changes to the project evaluation stage that would facilitate economic transmission projects.

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[235] See discussion in Section VII.F. See 2022 Project Candidate: *Capacity Transfer Rights for Internal Transmission Upgrades*.

[236] See discussion in Section VII.G.

[237] See NYISO presentations on *Economic Planning Process Improvement* to Electric System Planning Working Group (ESPWG) and FERC Docket ER21-1074.

Analytic Appendix

2020 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 2020 in the following areas:

- Wholesale market prices;
- Fuel prices, and generation by fuel type;
- Fuel usage under tight gas supply conditions;
- Load levels;
- Day-ahead ancillary services prices;
- Price corrections;
- Day-ahead energy market performance; and
- Day-ahead ancillary services market performance.

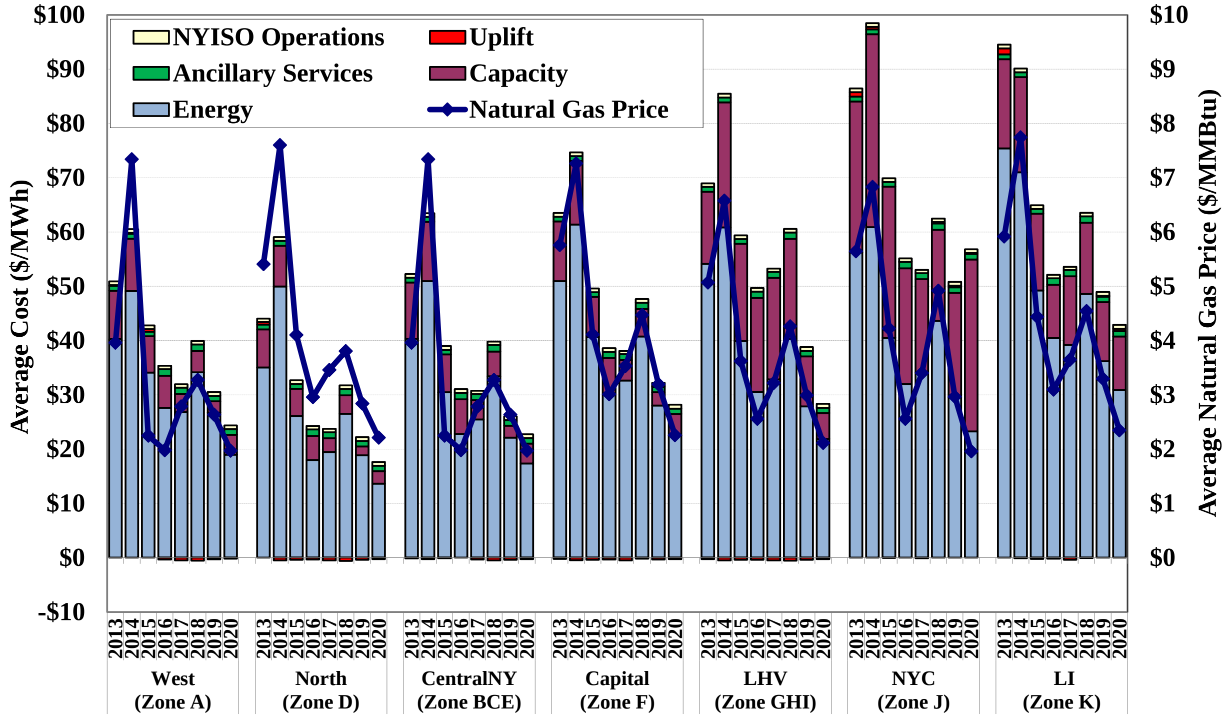
A. Wholesale Market Prices

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

The first analysis summarizes the energy prices and other wholesale market costs by showing the all-in price for electricity, which reflects the total costs of serving load from the NYISO markets. The all-in price includes the costs of energy, uplift, capacity, ancillary services, and NYISO cost of operations. The all-in price is calculated for various locations in New York State because both capacity and energy prices vary substantially by location.

The energy prices in this metric are load-weighted average real-time energy prices. The capacity component is calculated based on clearing prices in the monthly spot auctions and capacity obligations in each area, allocated over the energy consumption in that area. The uplift component is based on local and statewide uplift from Schedule 1 charges, allocated over the energy consumed in the area. For the purposes of this metric, costs associated with ancillary services are distributed evenly across all locations. Figure A-1 shows the average all-in prices along with the average natural gas prices from 2013 to 2020 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
2013 – 2020



Natural gas prices are based on the following gas indices (plus a transportation charge): (a) the Niagara index during the months December through March and Tennessee Zone 4 200L index during the rest of the year for the West Zone and for Central New York; (b) the Iroquois Waddington index for North Zone; (c) the minimum of Tennessee Zone 6 and Iroquois Zone 2 indices for the Capital Zone; (d) the average of Iroquois Zone 2 index and the Tetco M3 index for Lower Hudson Valley; (e) the Transco Zone 6 (NY) index for New York City, and (f) the Iroquois Zone 2 index for Long Island.[238] An incremental 6.9 percent tax rate is also reflected in the natural gas prices for New York City. An incremental 1 percent tax rate is reflected for Long Island on top of the delivered gas prices. [239]

238 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.

239 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.

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 time-weighted integrated real-time energy prices in 2019 and 2020, 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
2019-2020

	Annual Average			January Average			Rest-of-Year Average		
	2019	2020	% Change	2019	2020	% Change	2019	2020	% Change
Gas Prices ($/MMBtu)									
Tennessee Z4 200L	$2.26	$1.69	-25%	$2.91	$1.82	-38%	$2.19	$1.68	-24%
Tetco M3	$2.39	$1.59	-33%	$4.35	$2.09	-52%	$2.21	$1.55	-30%
Transco Z6 (NY)	$2.59	$1.64	-37%	$6.02	$2.20	-63%	$2.27	$1.59	-30%
Iroquois Z2	$3.05	$2.09	-31%	$6.95	$2.76	-60%	$2.68	$2.03	-24%
Tennessee Z6	$3.26	$2.13	-35%	$7.03	$2.98	-58%	$2.91	$2.05	-29%
Niagara	$2.34	$1.47	-37%	$3.69	$1.83	-50%	$2.21	$1.44	-35%
Dominion North	$2.10	$1.39	-34%	$2.86	$1.65	-42%	$2.03	$1.37	-33%
Energy Prices ($/MWh)									
West (Niagara & TN Z4 200L)	$25.49	$17.76	-30%	$33.74	$15.54	-54%	$24.72	$17.97	-27%
Capital Zone (Min of Iroq. & TN Z6)	$26.87	$21.38	-20%	$44.37	$25.26	-43%	$25.24	$21.02	-17%
Lw. Hudson (Avg of Tetco M3 & Iroq.)	$26.06	$20.28	-22%	$42.01	$22.94	-45%	$24.58	$20.03	-19%
New York City (Transco)	$28.21	$21.97	-22%	$43.78	$28.19	-36%	$26.76	$21.39	-20%
Long Island (Iroquois)	$33.33	$28.03	-16%	$48.25	$25.97	-46%	$31.95	$28.22	-12%

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 2020 for the seven locations shown in Figure A-2. The table overlapping the chart shows the annual averages of natural gas costs and LBMPs for 2019 and 2020. 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.[240]

240 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, 2020

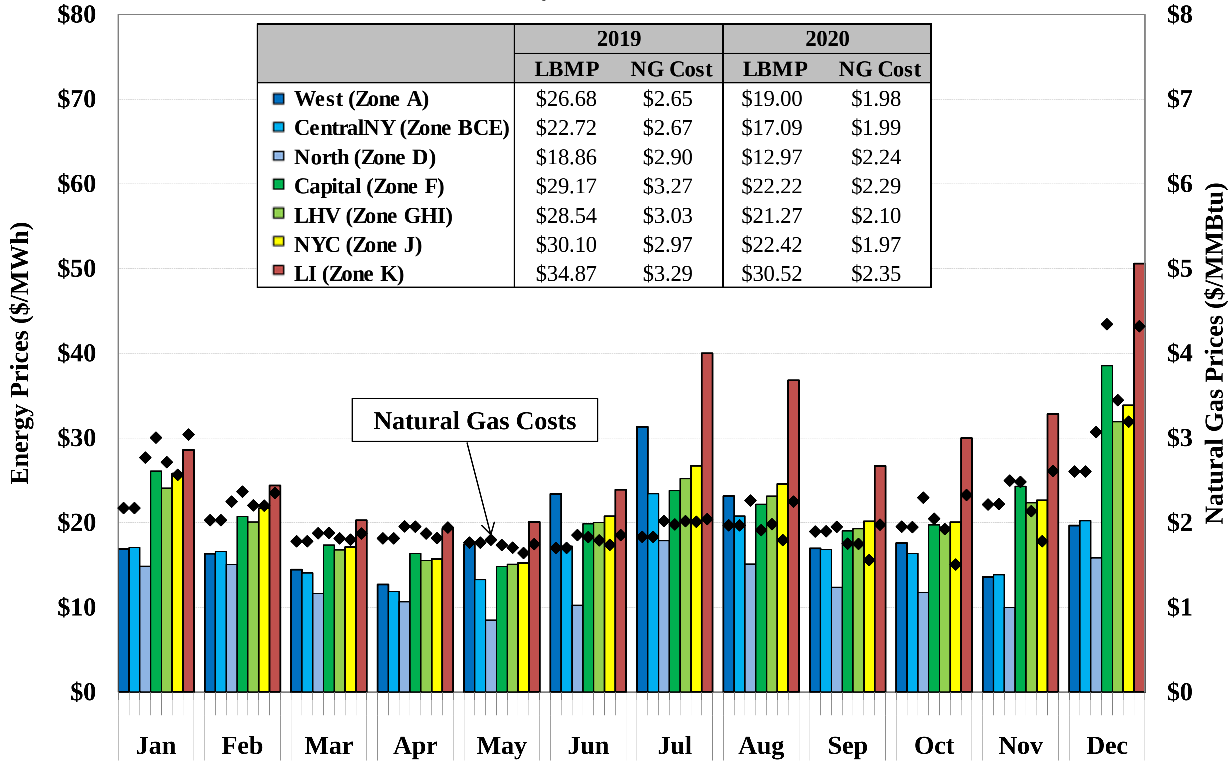


Figure A-: Average Monthly Implied Marginal Heat Rate

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).[241] 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.[242]

Figure A- shows the load-weighted average implied marginal heat rate in each month of 2020 for the seven locations shown in Figure A- and in Figure A-2. The table in the chart shows the annual averages of the implied marginal heat rates in 2019 and in 2020 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.

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

242 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, 2020

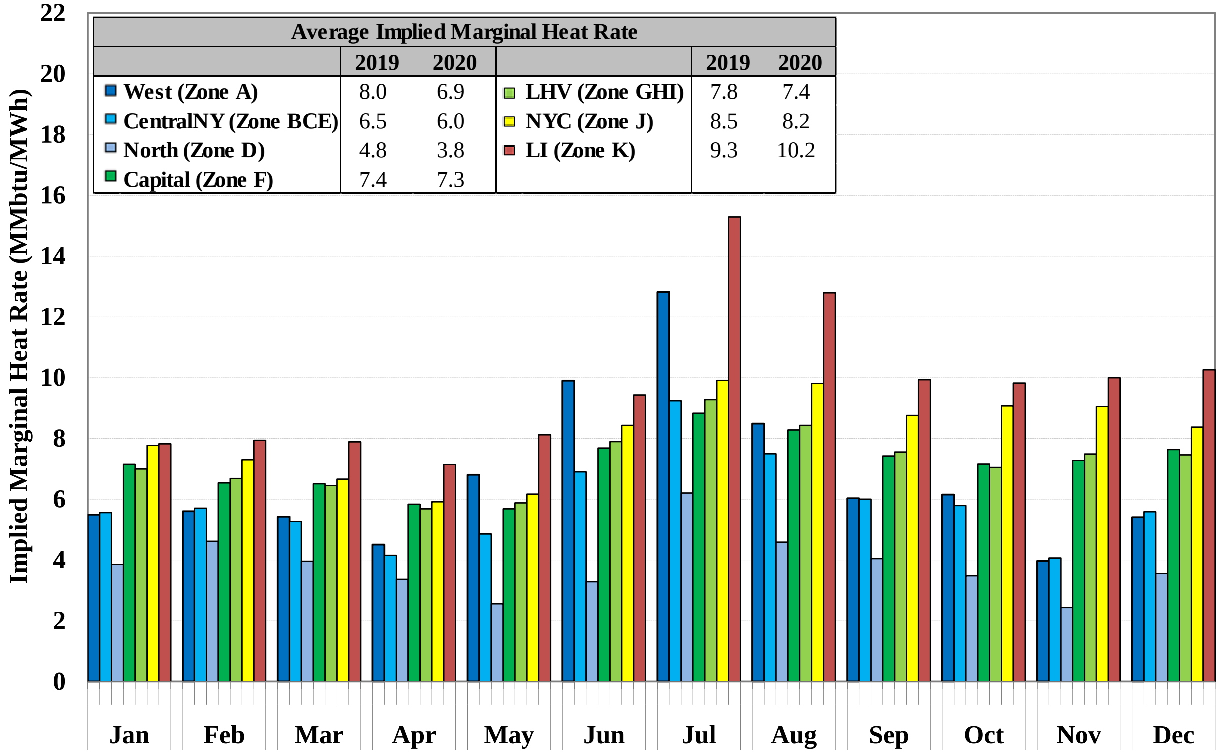


Figure A-4 – Figure A-5: Price Duration Curves and Implied Heat Rate Duration Curves

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 2020, 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 2020 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.[243] 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.

243 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
2020

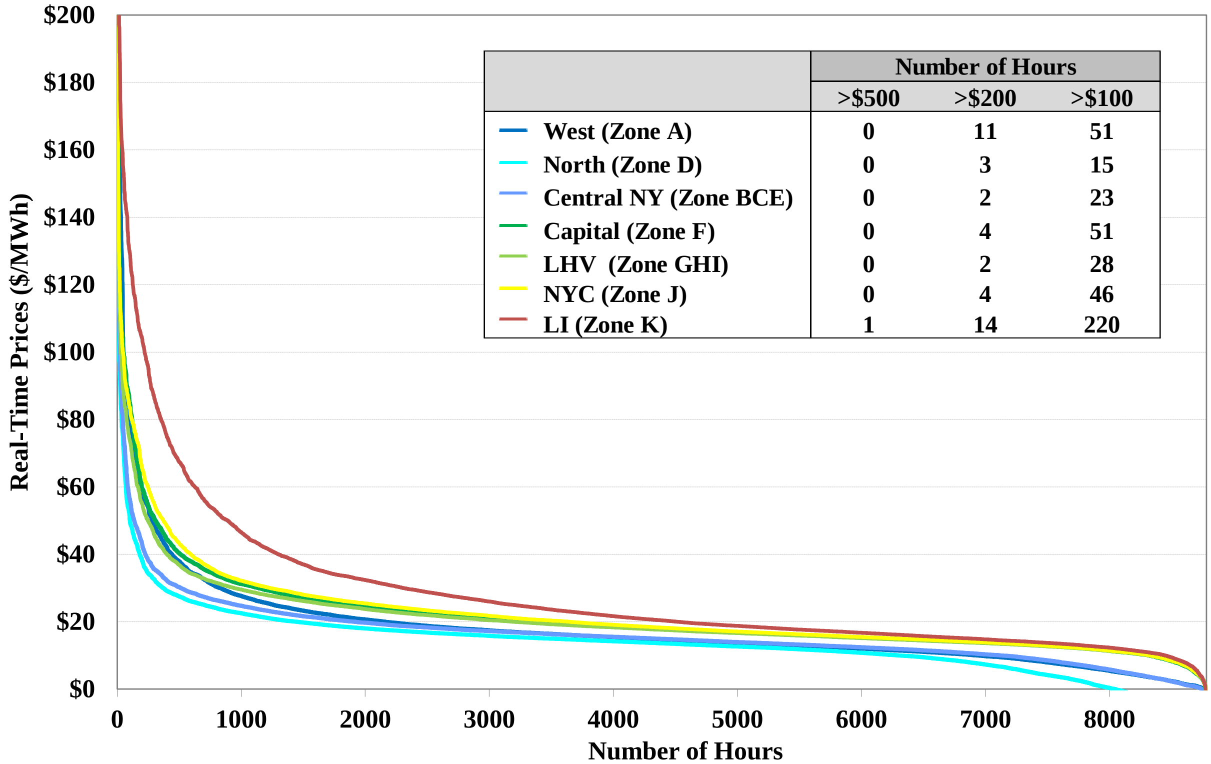
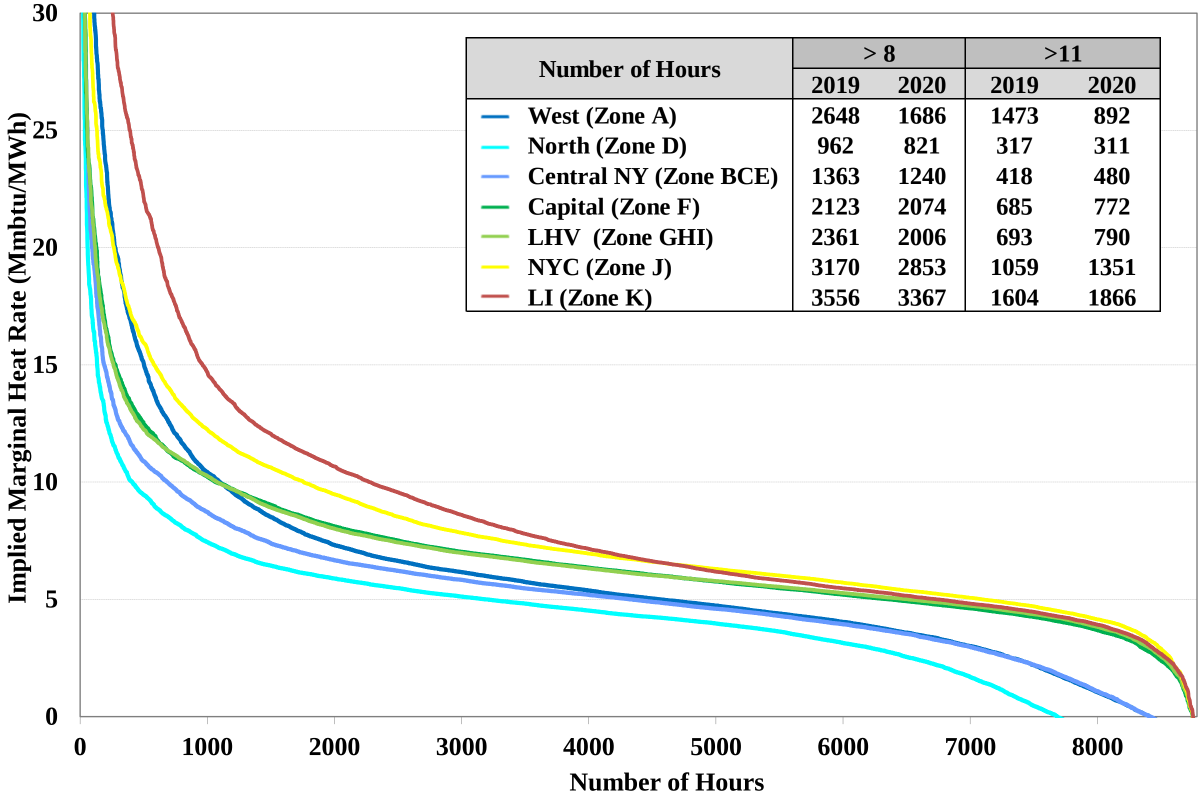


Figure A-5 shows the implied marginal heat rate duration curves at each location from the previous chart during 2020. Each curve shows the number of hours on the horizontal axis when the implied marginal heat rate for each sub-region was greater than the level shown on the vertical axis. The calculation of the implied marginal heat rate is similar to the one in Figure A-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 2019 and 2020.

Figure A-5: Implied Heat Rate Duration Curves by Region
2020



Number of Hours	> 8		>11	
	2019	2020	2019	2020
West (Zone A)	2648	1686	1473	892
North (Zone D)	962	821	317	311
Central NY (Zone BCE)	1363	1240	418	480
Capital (Zone F)	2123	2074	685	772
LHV (Zone GHI)	2361	2006	693	790
NYC (Zone J)	3170	2853	1059	1351
LI (Zone K)	3556	3367	1604	1866

<u>Key Observations: Wholesale Market Prices</u>

- Average all-in prices of electricity ranged from roughly $18/MWh in the North Zone to $58/MWh in New York City in 2020.
  - All-in prices fell in all regions except for New York City from 2019 to 2020. The prices in individual regions fell by 12 percent to 26 percent, but rose by 12 percent in New York City.
- Energy costs accounted for 40 to 78 percent of the all-in prices in the downstate regions, and 74 to 76 percent of all-in prices in upstate regions.
  - Energy costs in all regions decreased by 15 to 29 percent from 2019 to 2020. Low natural gas prices coupled with a significant decrease in load due to the effects of the Covid-19 pandemic drove the majority of this reduction in 2020.
    - Natural gas prices during the winter season often exhibit high volatility, which contributed significantly to the annual energy costs in recent years. However, the winter of 2020 was milder than any winter over the past several years. As a result, the natural gas prices in January 2020 were substantially lower when compared to prices in January 2019. For example, in January 2020, the Transco

Zone 6 NY index price averaged just $2.20 per MMBtu, which was 63 percent lower than in January 2019, which was already a mild winter.[244]

- Natural gas prices during the rest of the year were also historically low due to the economic effects of the Covid-19 pandemic, which led to reduced demand for natural gas. Consequently, the 2020 natural gas prices, especially in the Eastern New York, were lower even the previous historic lows witnessed during 2016.

- The shutdowns that were part of the response to the Covid-19 pandemic drove significant reductions in annual load across the state, especially in NYC, despite a warmer than average summer in 2020 (see subsection D).

  - In 2020, the highest energy costs occurred in Long Island, especially during the peak summer months (i.e., July through September) when the load increased, in line with hotter than usual weather and the shift to higher residential cooling requirements. Furthermore, congestion into Long Island was exacerbated by several major transmission outages during the summer months (see Section III of the Appendix). In addition, as the weather became colder in December, day-ahead energy prices in Long Island increased commensurately with the increase in gas prices.

- Capacity costs accounted for 16 to 55 percent of the all-in price in downstate regions and 13 to 16 percent of the all-in price in the upstate regions. In 2020:
  - Capacity costs rose in New York City by 65 percent year-over-year primarily because of a 3.8 percentage point increase in the Locational Capacity Requirement ("LCR").
  - Lower Hudson Valley capacity costs fell nearly 50 percent due primarily to a 2.3 percentage point reduction in the LCR.
  - Capacity costs in Rest of State ("ROS") rose by 41 to 75 due to a 1.9 percentage point increase in the Installed Reserve Margin ("IRM"), and reductions in internal supply.
  - Long Island saw a 10 percent reduction in capacity costs due to a 0.7 percentage point reduction in the LCR (see Section V in the Appendix).

- The average implied marginal heat rates fell from 2019 to 2020 in most regions in line with the low load levels and low gas prices.
  - In 2020, the steepest year-over-year reductions in the average implied marginal heat rates occurred in the North Zone (11 percent) and in the West Zone (15 percent). In addition to low loads and gas prices, the following factors contributed to lower implied marginal heat rates:
    - The West Zone saw less congestion in 2020 due to fewer transmission outages, lower regional gas price spreads, and reduced electric load in eastern NY.

244 The average gas prices in January 2020 in eastern New York were as much as 88 percent lower than the average prices during January 2018, which contained an extended cold spell.

  - Long term transmission outages due to the Moses-Adirondack Smart Path Reliability Project contributed to an increase in export congestion out of the North Zone, which reduced the implied market heat rates in that zone.

- The only zone that witnessed a year-over-year increase in the average implied marginal heat rate in 2020 was Long Island. In addition, the average implied marginal heat rates in the Capital Zone and in New York City increased slightly (by one percent) during the non-Winter months.[245]
  - The average implied marginal heat rates in these zones were elevated during the summer months due to warmer than normal weather, especially in the month of July.
  - Furthermore, in case of Long Island, the Cross Sound Cable was out of service beginning early July that persisted until late October. This line often provides significant congestion relief to gas-constrained portions of eastern Long Island. Hence, its prolonged outage contributed to higher congestion and implied marginal heat rates in 2020.

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.[246] 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.[247] 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.[248]

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.

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245 On an annual basis, the average implied marginal heat rates in the Capital Zone and in New York City decreased by two percent and three percent in 2020, respectively.

246 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.

247 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.

248 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.

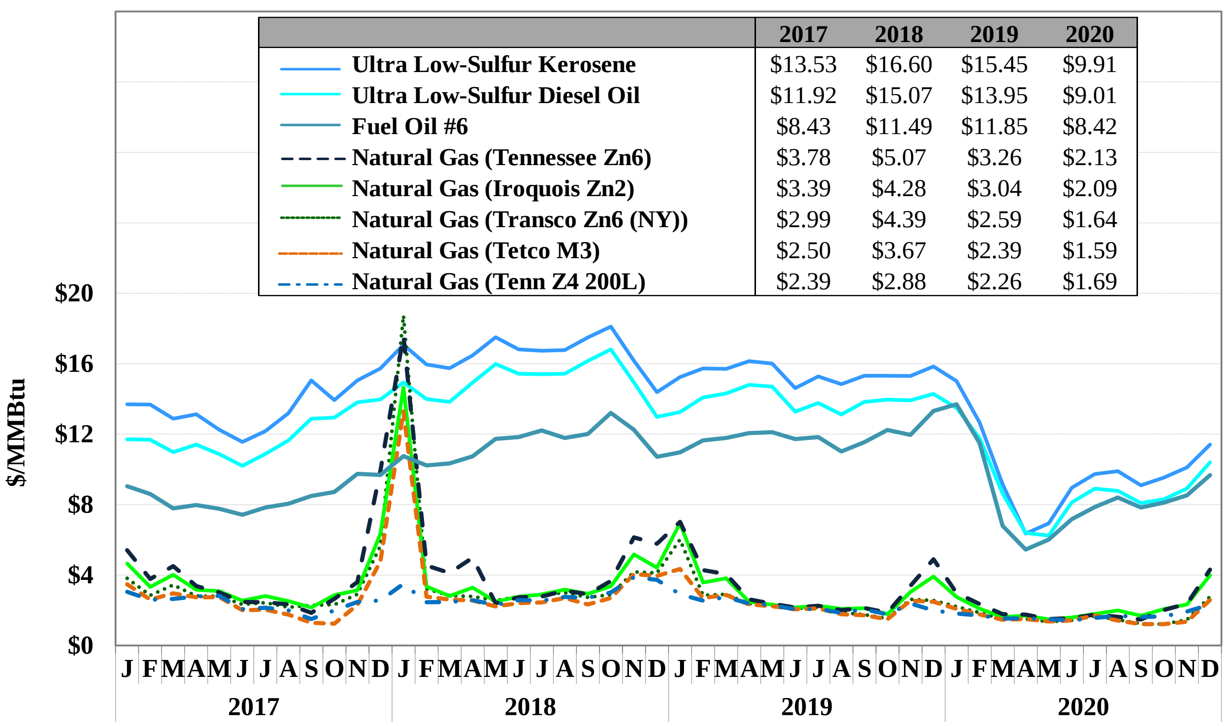
However, bottlenecks on the natural gas system can sometimes lead to significant differences in delivered gas costs by area, particularly during peak winter conditions. This in turn can produce comparable differences in energy prices when network congestion occurs. The natural gas price differences generally 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 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;
- 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 and Central Zone.

Figure A-6 shows average natural gas and fuel oil prices by month from 2017 to 2020. The table compares the annual average fuel prices for these four years.

Figure A-6: Monthly Average Fuel Index Prices [249]

2017 – 2020



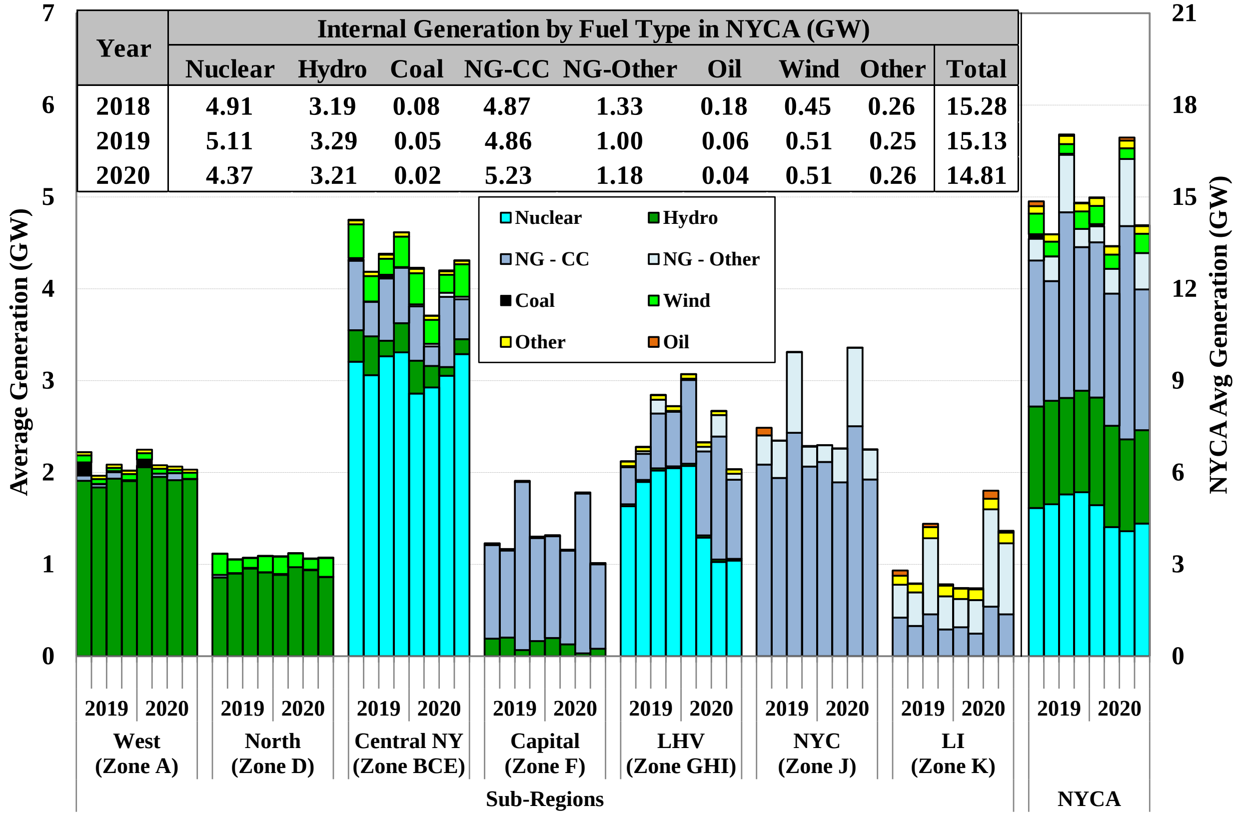
	2017	2018	2019	2020
Ultra Low-Sulfur Kerosene	$13.53	$16.60	$15.45	$9.91
Ultra Low-Sulfur Diesel Oil	$11.92	$15.07	$13.95	$9.01
Fuel Oil #6	$8.43	$11.49	$11.85	$8.42
Natural Gas (Tennessee Zn6)	$3.78	$5.07	$3.26	$2.13
Natural Gas (Iroquois Zn2)	$3.39	$4.28	$3.04	$2.09
Natural Gas (Transco Zn6 (NY))	$2.99	$4.39	$2.59	$1.64
Natural Gas (Tetco M3)	$2.50	$3.67	$2.39	$1.59
Natural Gas (Tenn Z4 200L)	$2.39	$2.88	$2.26	$1.69

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

Figure A-7 shows the quantities of generation by fuel type in seven regions of New York in each quarter of 2020 as well as for NYCA as a whole.[250] The table in the chart shows annual average generation by fuel type from 2018 to 2020.

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

By Quarter by Region, 2020



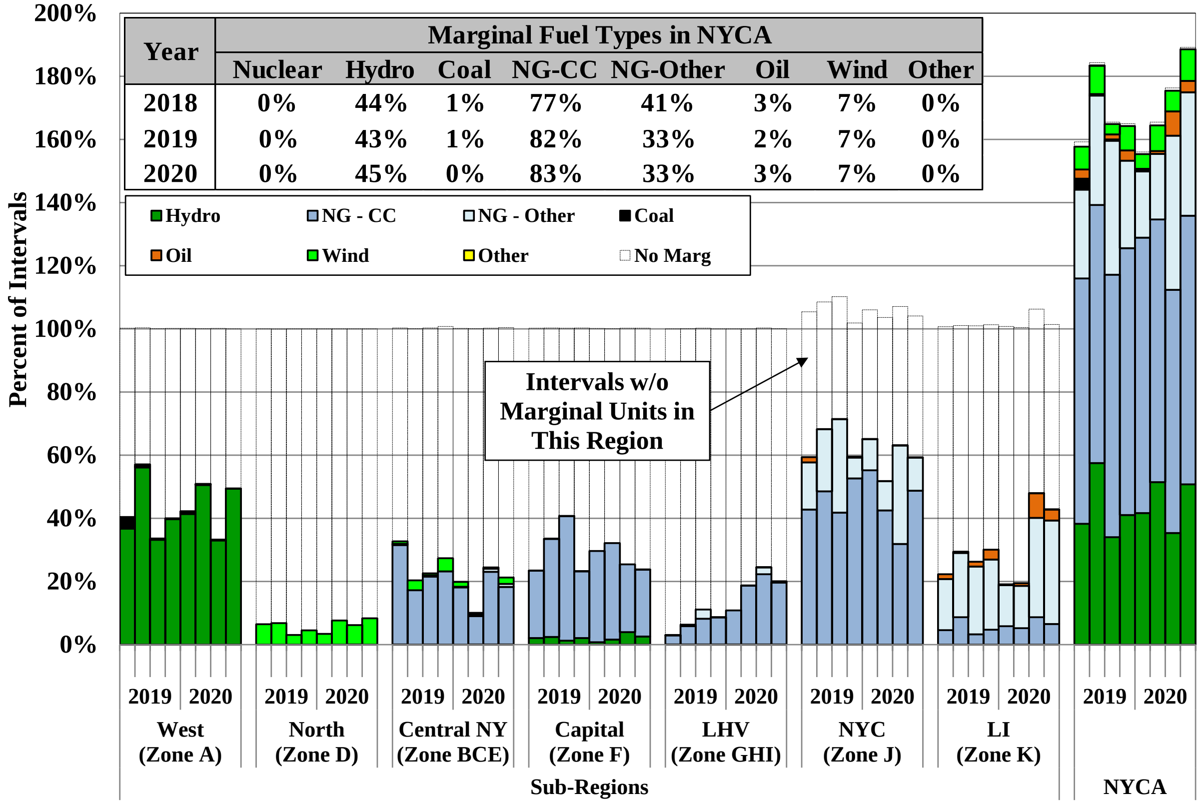
Year	Internal Generation by Fuel Type in NYCA (GW)								
	Nuclear	Hydro	Coal	NG-CC	NG-Other	Oil	Wind	Other	Total
2018	4.91	3.19	0.08	4.87	1.33	0.18	0.45	0.26	15.28
2019	5.11	3.29	0.05	4.86	1.00	0.06	0.51	0.25	15.13
2020	4.37	3.21	0.02	5.23	1.18	0.04	0.51	0.26	14.81

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 2020. 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").

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

Figure A-8: Fuel Types of Marginal Units in the Real-Time Market in New York
By Quarter by Region, 2020



Year	Marginal Fuel Types in NYCA							
	Nuclear	Hydro	Coal	NG-CC	NG-Other	Oil	Wind	Other
2018	0%	44%	1%	77%	41%	3%	7%	0%
2019	0%	43%	1%	82%	33%	2%	7%	0%
2020	0%	45%	0%	83%	33%	3%	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 in 2020 were the lowest observed in most locations across the state for more than a decade.
  - Natural gas index prices across the state fell by 25 to 35 percent from 2019 to 2020, due to the effects of the Covid-19 pandemic and an unusually mild winter.
  - The lowest annual natural gas prices during the past decade were observed in 2016. The gas index prices for Eastern New York in 2020 were 26 to 31 percent lower than the average prices during 2016.
  - Gas price differentials across the state generally play a significant role in the congestion patterns in the state (see Section III of the Appendix). In 2020, the spread between the prices of Western New York gas indices (such as Tennessee Z4 200L) and Eastern New York gas indices (such as Transco Z6 NY) narrowed substantially.

  - Contrary to historical trends, the average Transco Z6 NY price in 2020 was three percent lower than the Tennessee Z4 200L index price. The Tennessee Zone 4 200L index exhibited an average discount of 34 percent relative to the Transco Zone 6 NY index in 2018, and 13 percent in 2019.

  - The other Eastern New York gas indices continued to priced higher in 2020 relative to the Western NY regions by a 24 percent to 26 percent.

- Gas-fired (43 percent), nuclear (30 percent), and hydro (22 percent) generation accounted for 95 percent of all internal generation in New York during 2020.
  - Gas-fired production increased by 9.4 percent from 2019, and nearly 3.5 percent from 2018 despite the reduced electric demand across much of 2020. The increase in output among gas units was driven by increased output from both combined cycle units and steam turbines.
    - The higher output from combined cycle units was a result of nearly 1.8 GW of new entry in the Hudson Valley zone in recent years. The 680-MW CPV Valley unit entered the market in the summer of 2018, and the 1100-MW Cricket Valley unit entered the market in 2020.
    - Steam turbine production in 2020 increased from 2019 because of higher output from Long Island units during the second half of the year. Output from these units was required to offset outages of transmission lines into Long Island.
  - Average nuclear generation fell by 740 MW from 2019, reflecting the impact of the Indian Point 2 retirement in April 2020.
  - Average coal-fired generation fell by 30 MW from 2019. Coal production fell to zero by in the last three quarters as the last operating coal unit, Kintigh, retired as of April 1, 2020.
  - Average oil-fired generation decreased by 20 MW (or roughly 36 percent) from 2019 levels.
    - The level of oil-fired generation in 2020 was similar to what was seen in years with mild winter such as 2017 and 2019, but it was significantly lower (79 percent) than in 2018, when the most recent extended cold spell occurred.
    - Oil-fired generation in prior years has generally been higher in the winter season during periods of natural gas price volatility. However, given the absence of gas market volatility in winter of 2020, most of the oil-fired generation occurred during the summer on the east end of Long Island, where oil-fired units were dispatched to manage constraints on the low voltage system (see Section III.D of the Appendix).

- Gas-fired and hydro resources continued to be marginal for the vast majority of time in 2020.

- Most hydro units on the margin have storage capacity, leading them to offer based partly on the opportunity cost of foregone sales in other hours (when gas units are marginal). Thus, the prices set by hydro units are also affected by natural gas prices.

C. Fuel Usage Under Tight Gas Supply Conditions

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

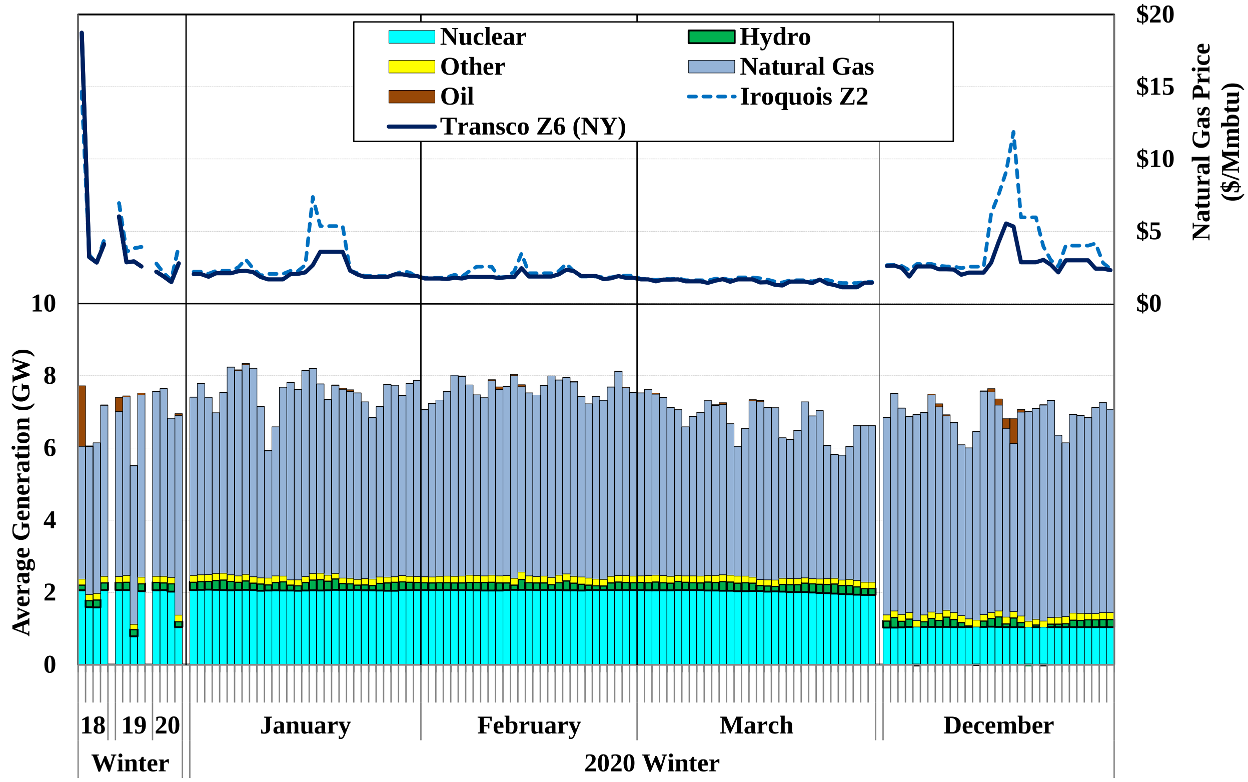
- Not having the necessary air permits;
- Not having oil-firing equipment in serviceable condition;
- Low on-site oil inventory;
- Physical limitations and gas scheduling timeframes that may limit the flexibility of dual-fueled units to switch from one fuel to the other; and
- NOx emissions limitations.

This subsection examines actual fuel usage in the winter of 2020, 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 2020 (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 2018 and 2020. 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, 2020



Key Observations: Fuel Usage Under Tight Gas Supply Conditions

- Oil-fired generation in Eastern New York totaled just 54 GWh in the four-month period (i.e., January to March, and December) of winter in 2020. This represents a 85 percent decline from the winter months of 2019 and a 96 percent decrease from the winter months of 2018.

- In 2020, over one GW of nuclear generation (from Indian Point Unit 2) in Eastern New York retired, and nearly 1.1 GW of gas-fired generation (from Cricket Valley) entered the market. Consequently, gas-fired generation was 82 percent of the total generation in Eastern New York during December 2020, whereas it was 68 percent for the months of January through March 2020 when the Indian Point Unit 2 was still in service. Hence, under tight supply conditions, the performance of the generation capacity in Eastern New York could increasingly be driven by gas market dynamics, particularly as additional nuclear capacity leaves the market.

    - For instance, several pipelines issued operational flow orders beginning gas day December 15 as temperatures fells and system conditions tightened. A considerable amount of capacity from gas-only unit(s) in Eastern New York reported during this period an inability to secure natural gas resulting in higher prices and some amount of forced outages due to lack of fuel availability.

- 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.

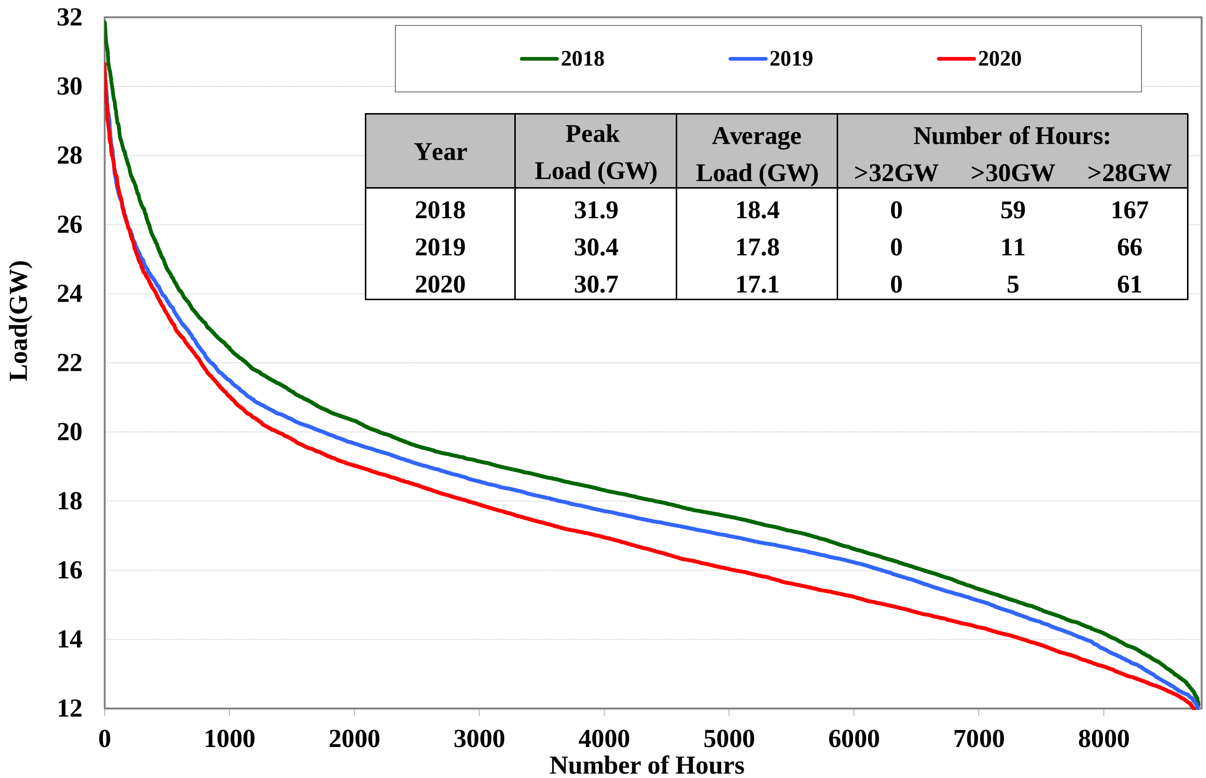
D. Load Levels

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
2018 – 2020



Year	Peak Load (GW)	Average Load (GW)	Number of Hours: >32GW	>30GW	>28GW
2018	31.9	18.4	0	59	167
2019	30.4	17.8	0	11	66
2020	30.7	17.1	0	5	61

Key Observations: Load Levels

- Average loads were historically low in 2020, but a warmer-than-average summer resulted in a peak demand value that was marginally higher than in 2019.
  - The annual average load in 2020 was just 17.1 GW, which was four percent lower than in 2019. The average load in 2019 had been the lowest observed in over a decade.
  - Average load across the state was significantly impacted by the response to the Covid-19 pandemic that began in March 2020. The impact on load ranged from two percent to 20 percent during the year with the largest impact occurring at the height of the statewide shutdowns in the spring.[251]
  - Notwithstanding the effects of the pandemic, the annual peak increased by one percent year-over-year in 2020 due to hot weather during the months of July and August.

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 2019 and 2020. 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:

251 NYISO regularly provides updates on the estimated impact of the Covid pandemic on load levels which can be accessed at https://www.nyiso.com/covid.

- 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

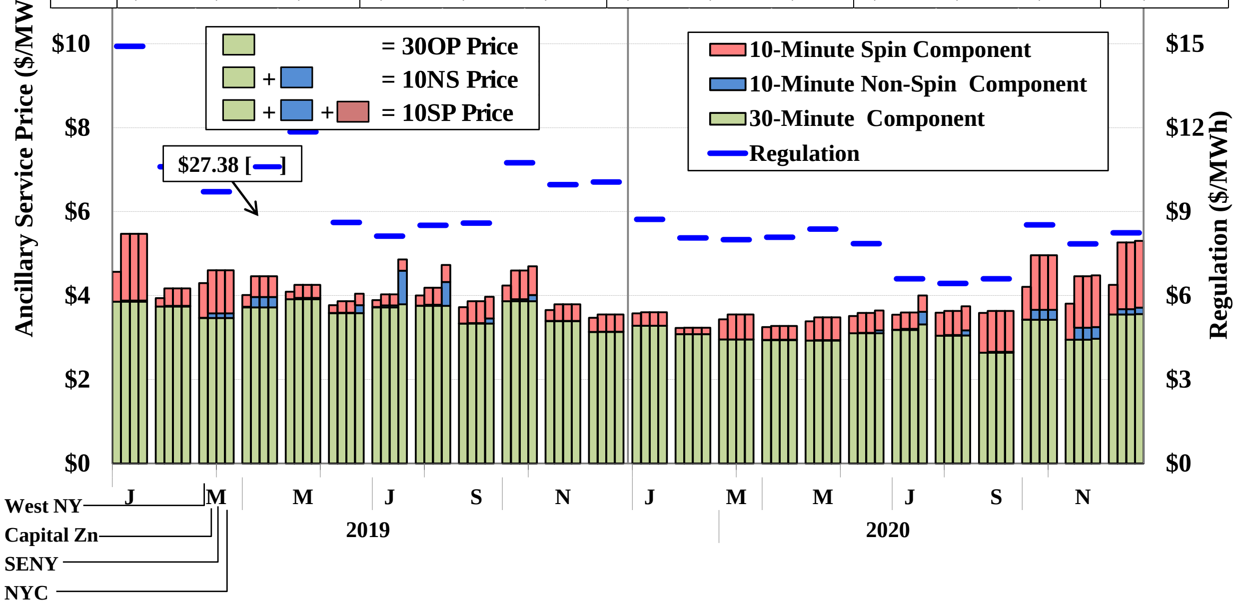
- The 10-minute spinning component represents the cost to simultaneously meet the 10-minute spinning reserve requirements for New York City, East New York and NYCA (Southeast New York does not have a separate 10-minute spinning reserve requirement).

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 2019 and 2020 on an annual basis.

Figure A-11: Day-Ahead Ancillary Services Prices

2019- 2020

	West NY			Capital Zone			Southeast NY			New York City			Regulation
Year	10SP	10NS	30OP	10SP	10NS	30OP	10SP	10NS	30OP	10SP	10NS	30OP	
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	$11.83
2020	$3.62	$3.09	$3.09	$3.86	$3.15	$3.09	$3.86	$3.15	$3.09	$3.91	$3.20	$3.10	$7.78



Key Observations: Day-ahead Ancillary Service Prices

- The average day-ahead prices for all reserve products fell in 2020. This is consistent with the decrease in opportunity costs associated with lower energy prices.

- Prices of the 10-minute spinning reserves rose in the fourth quarter because of: (a) an increase in planned generator outages in the fall, (b) higher energy prices that resulted from rising gas prices, and (c) the effect of the Covid-19 pandemic on load reductions began to subside.

- Average day-ahead regulation prices in 2020, when compared to 2019, decreased by 34 percent. Excluding the April prices due to the extraordinary events of that month in 2019, the year-over-year reduction was 24 percent. (see Section II)
  - In April 2019, the regulation capacity offered was reduced significantly because of planned outages and low load levels, which led some regulation-capable units to be offline (and unavailable to provide regulation). Consequently, regulation prices cleared on 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.[252]
  - Despite the decrease in prices during 2020, there was a modest increase in the regulation requirement in September 2020, the first such increase in several years.
    - Prices fell nonetheless due to an increase in the capacity offered by approximately 190 MW and the significant reduction in the offered prices. (see Section II of the Appendix for more on this)
  - The Tariff does not require generators to offer regulation capacity.
    - 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.
    - Additionally, the costs to regulate can be difficult to estimate for some generators, and the tariff allows for mitigation of regulation capacity and movement bids independently. Hence, misallocation of costs between these products could lead to situations where bids for one of the two products are mitigated, even though the composite offer does not exceed the comparable composite reference level.

- 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 continued to exhibit small premiums relative to the prices for corresponding SENY reserve products.
  - Cheap gas prices and low load levels in 2019 and 2020 led to less volatile conditions in New York City, which likely reduced the potential premium for New York City reserve products.

252 See our Quarterly Report for the Second Quarter of 2019.

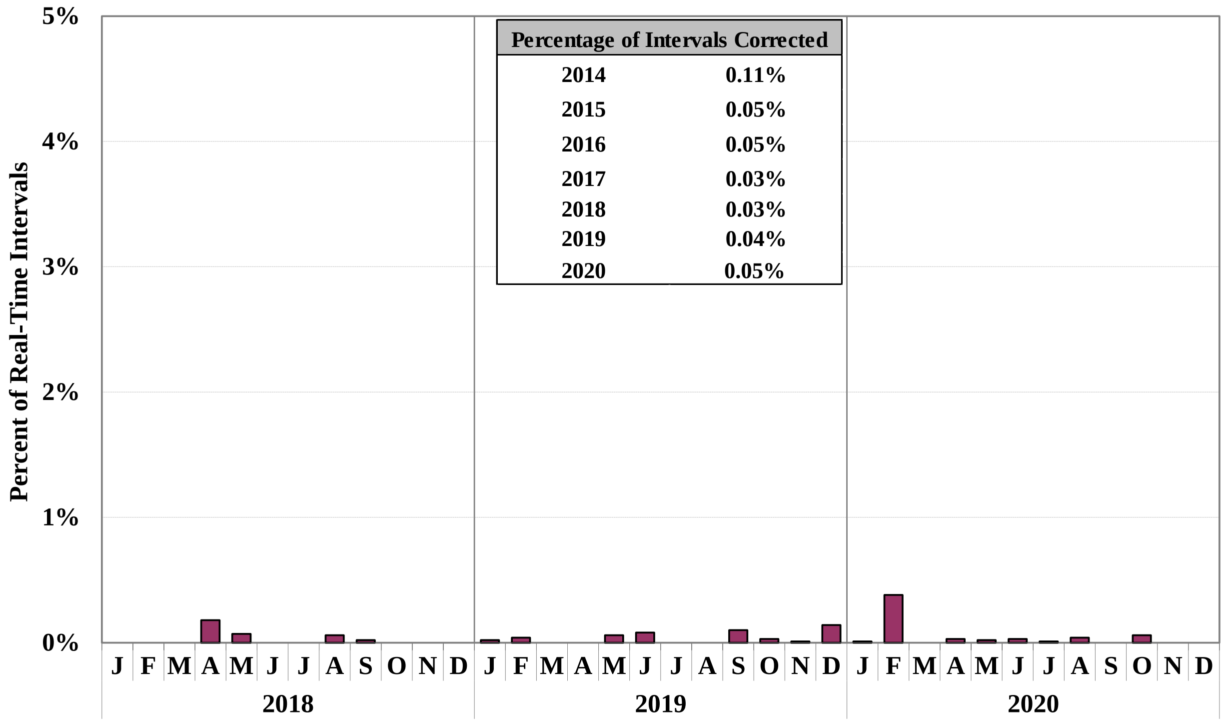
F. Price Corrections

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 2018 to 2020. 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
2018-2020



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.

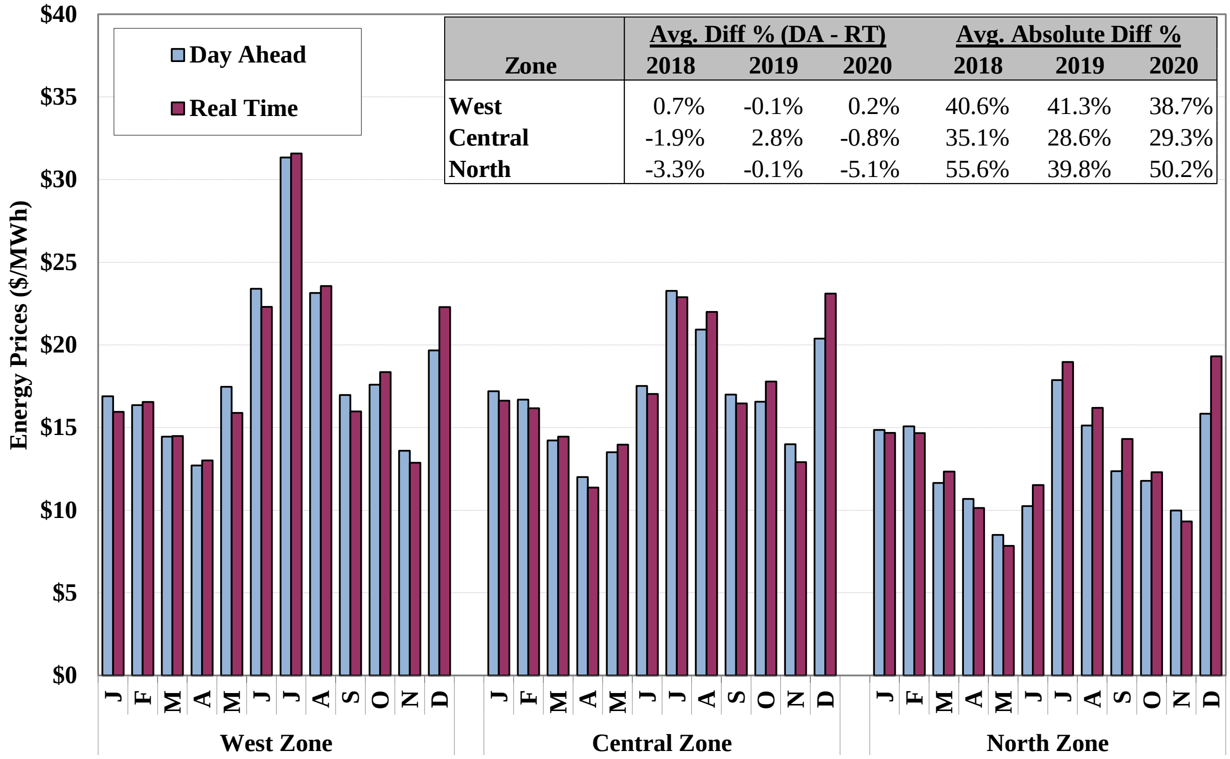
In this section, we evaluate two aspects of convergence in prices between day-ahead and real-time markets and look for evidence of persistent differences. First, we examine the consistency of average day-ahead energy prices with average real-time energy prices at the zone level. Second, we evaluate the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

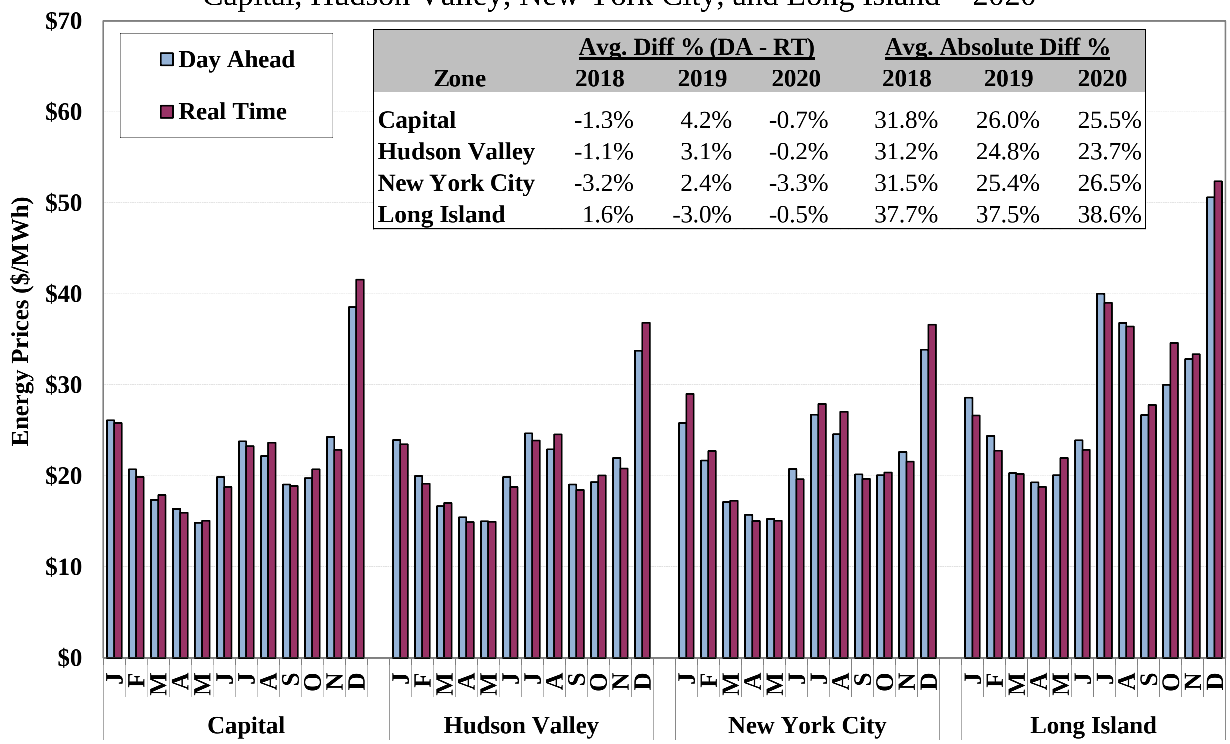
Figure A-13 and Figure A-14 compare day-ahead and real-time energy prices in West Zone, Central Zone, North Zone, Capital Zone, and Hudson Valley, New York City, and Long Island. The figures are intended to reveal whether there are persistent systematic differences between the load-weighted average day-ahead prices and real-time prices at key locations in New York. The bars show average monthly day-ahead and real-time prices weighted on the hourly day-ahead load in each zone. 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 – 2020



Zone	Avg. Diff % (DA - RT) 2018	2019	2020	Avg. Absolute Diff % 2018	2019	2020
West	0.7%	-0.1%	0.2%	40.6%	41.3%	38.7%
Central	-1.9%	2.8%	-0.8%	35.1%	28.6%	29.3%
North	-3.3%	-0.1%	-5.1%	55.6%	39.8%	50.2%

Figure A-14: Average Day-Ahead and Real-Time Energy Prices in Eastern New York
Capital, Hudson Valley, New York City, and Long Island – 2020



Zone	Avg. Diff % (DA - RT) 2018	2019	2020	Avg. Absolute Diff % 2018	2019	2020
Capital	-1.3%	4.2%	-0.7%	31.8%	26.0%	25.5%
Hudson Valley	-1.1%	3.1%	-0.2%	31.2%	24.8%	23.7%
New York City	-3.2%	2.4%	-3.3%	31.5%	25.4%	26.5%
Long Island	1.6%	-3.0%	-0.5%	37.7%	37.5%	38.6%

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 2020 for selected locations in New York City, Long Island, and Upstate New York.[253] These are load-weighted averages based on the day-ahead forecasted load. The figure includes examples of select nodes and seasons for several regions that generally exhibited less consistency between average day-ahead and average real-time prices than other nodes. There is often seasonal variation associated with price convergence, and for this analysis, the summer months include June to August) and the winter months include December, January, and February.

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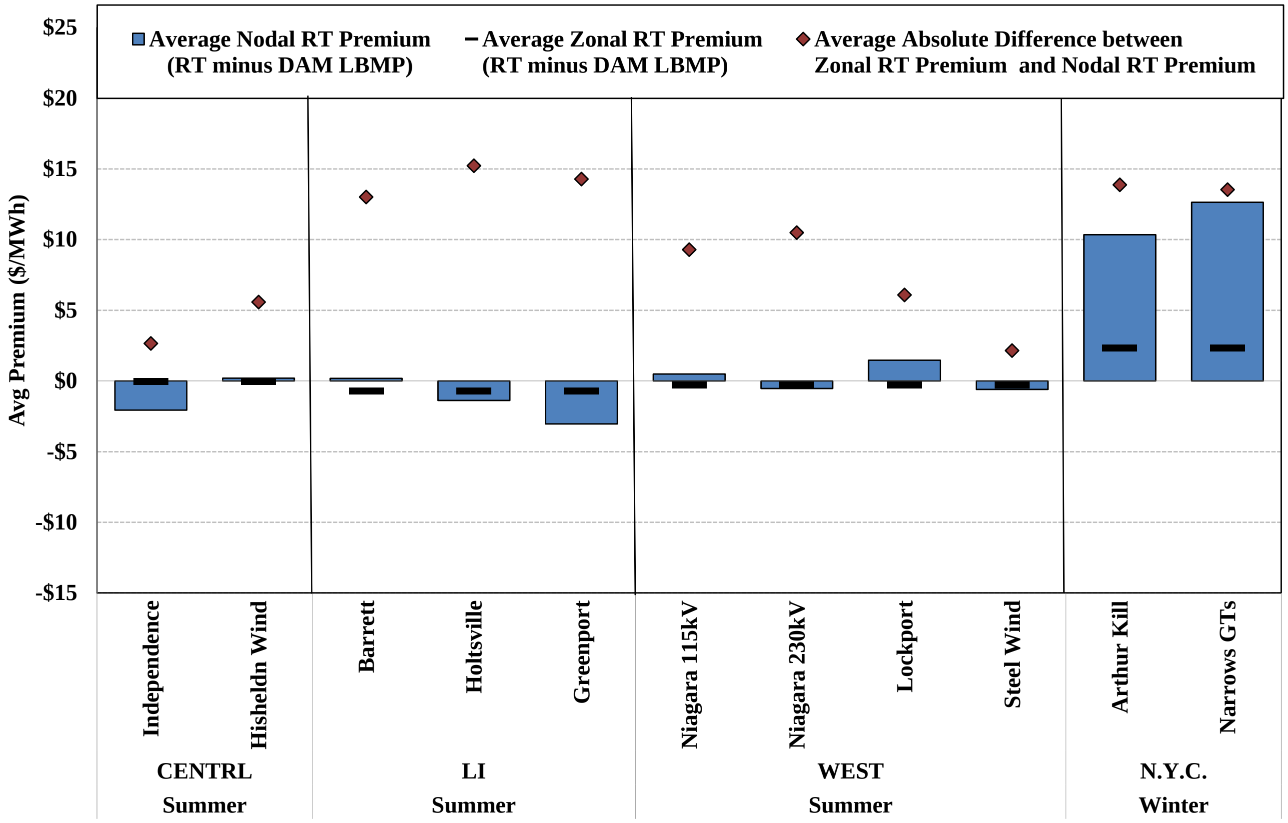
253 In the Central Zone, Independence is represented by the Sithe Independence GS1 bus, and Hisheldn Wind is represented by Hisheldon Wind Tower bus. In Long Island, Barret is the Barrett 1 bus, NYPA Holtsville is the NYPA Holtsville bus, and Greeport is the Global Greenport bus. In New York City, Arthur Kill is the Arthur Kill 2 bus and Narrows is the Narrows GT1 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
2020



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

- The annual average real-time prices in 2020 were at a premium of less than one percent of the average day-ahead price in most zones. With the exception of New York City and the North Zone, the average difference between real-time and day-ahead prices generally narrowed in 2020 relative to 2019.
  - Relatively low real-time price volatility led to small differences between most zones' day-ahead and real-time prices. Fewer unforeseen transmission outages also contributed to improved convergence in several areas.
  - Although the average difference between real-time and day-ahead prices was small in 2020, unlike most previous years, real-time prices exhibited a small premium over day-ahead prices in most regions. A small average day-ahead premium is consistent with historical patterns and is generally desirable in a competitive market. While this was true for most of the year, small real-time premiums occurred largely because of real-time price spikes during the cold weather and associated gas price volatility in December 2020.
  - The larger real-time price premium observed in New York City was driven by a combination of factors that include outages of transmission facilities (in particular,

the Gowanus-Greenwood line), transient congestion in certain load pockets, and limited availability of 5-minute ramping capability.

- In 2020, transmission work as part of the Moses-Adirondack Smart Path Reliability Project began in May and continued through the year. Outages related to this project resulted in lower transfer capability out of the North Zone, which affected the spread between day-ahead and real-time prices.
  - The resource mix in North Zone contains significant wind generation with few dispatchable resources. As a result, when there is limited transfer capability, real time prices in the North Zone can be volatile.[254] Furthermore, the load forecast errors in 2020 were higher than usual. Taken together, these factors resulted in an increase in the real-time price volatility (relative to 2019) as represented by the average absolute difference between day-ahead and real-time prices.
  - The net scheduled virtual load increased in the North from May 2020 through the end of the year in response to average real-time prices exceeding day-ahead prices in that period. However, the amount of net virtual load declined somewhat after the first month of outages, and was ultimately insufficient to reduce the average difference between real-time and day-ahead prices.[255]

- At the zonal level, real-time price volatility in 2020, as measured by the load-weighted average absolute difference between hourly day-ahead and real-time prices, was similar to 2019 across all zones (except for the North Zone, as discussed above).
- At the nodal level, a number of locations exhibited less consistency between average day-ahead and real-time prices in 2020 than at the zonal level. However, low gas price volatility and low load generally contributed to fewer extreme differences between real-time and the day-ahead than in prior years.
  - As more renewables are added to New York's generation portfolio in the coming years, the relationship between zonal and nodal convergence has potential to become more persistent and likewise more important to market participants. For instance, the use of nodal or zonal prices as the basis for renewable contract indices could potentially mean large differences in profits and investment incentives for generation depending on which is used. As an example, in the Central Zone in the summer months, the Hilsheldon node on average displays near-perfect nodal and, separately, zonal convergence ($0/MWh premiums), hiding the relatively large average absolute difference (i.e. volatility) between the nodal and zonal premiums (about $5/MWh). Though not yet a significant concern, we will continue to monitor the variability of

[254] The number of intervals where wind was on the margin in North Zone increased in the second quarter of 2020. See sub-section B.

[255] See Figure A-43. The increase in volatility of real-time prices could have made it challenging to determine the appropriate level of net virtual load.

nodal and zonal premium volatility across the state and discuss implications for generation investment incentives.

- In Long Island, inconsistency between zonal and nodal price convergence was more severe in 2020 partly due to extended outages in the zone, including that of the Cross Sound Cable in July and August. In addition, the following factors exacerbated the inconsistency:
  - Lower voltage constraints in Long Island were not modeled in 2020 which meant that pricing signals associated with congestion on those lines were not priced into the market for unit commitment. Although the extended outages in Long Island in the summer resulted in an increase in day-ahead commitment of generation, out-of-market actions still often occurred in real-time, leading to differences in scheduled generation between the day-ahead and real-time.
  - 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. NYISO revised some day-ahead PAR assumptions to reduce these differences in mid-July.
  - 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 zone, the Arthur Kill buses, and the Narrows GT buses all exhibited a real-time price premium in the 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 or very high real-time premiums depending on the location of the congestion. For instance, when nodal price premiums at Narrows and Arthur Kill are similarly high, as is the case in Winter 2020, this is illustrative of congestion upstream from these lines when the Gowanus-Greenwood line was out on maintenance for an extended period.
- In the West, unmodeled loop flows in the clockwise direction and operation of Niagara generation in real-time in a manner that does not minimize congestion can still exacerbate western congestion and nodal price divergence. Nodes in the West that lie outside of the more constrained pockets (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

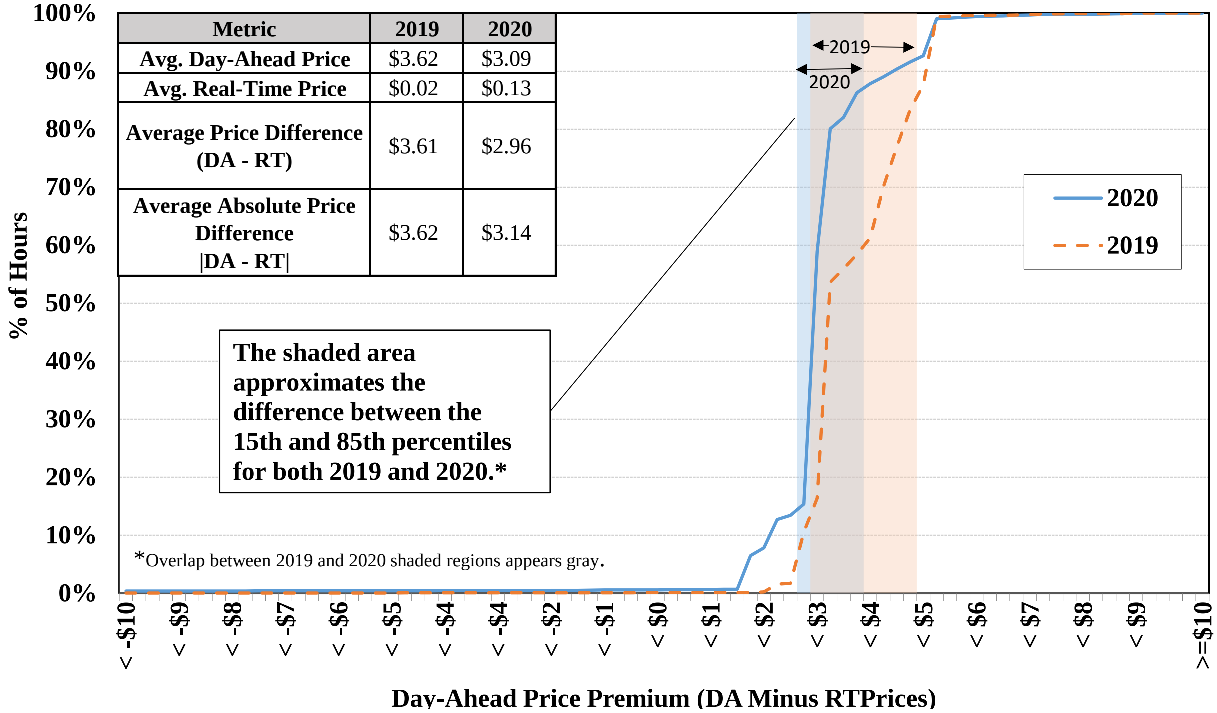
To evaluate the performance of the day-ahead ancillary service markets, the following seven figures show distributions of day-ahead premiums (i.e., day-ahead prices minus real-time prices) in: (a) Western 30-minute reserve prices; (b) Western 10-minute spinning reserve prices; (c) Eastern 10-minute spinning 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 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 $3.75 or less, in 2020 including intervals where the day-ahead premium was negative (i.e. real-time prices exceeded day-ahead prices).

The figures compare the distributions between 2019 and 2020.[256] The approximate 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 $3.75/MWh for 70 percent of the hours in 2020 (between $2.75 and $4.75/MWh in 2019). The inset tables summarize the following annual averages in 2019 and 2020: (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.

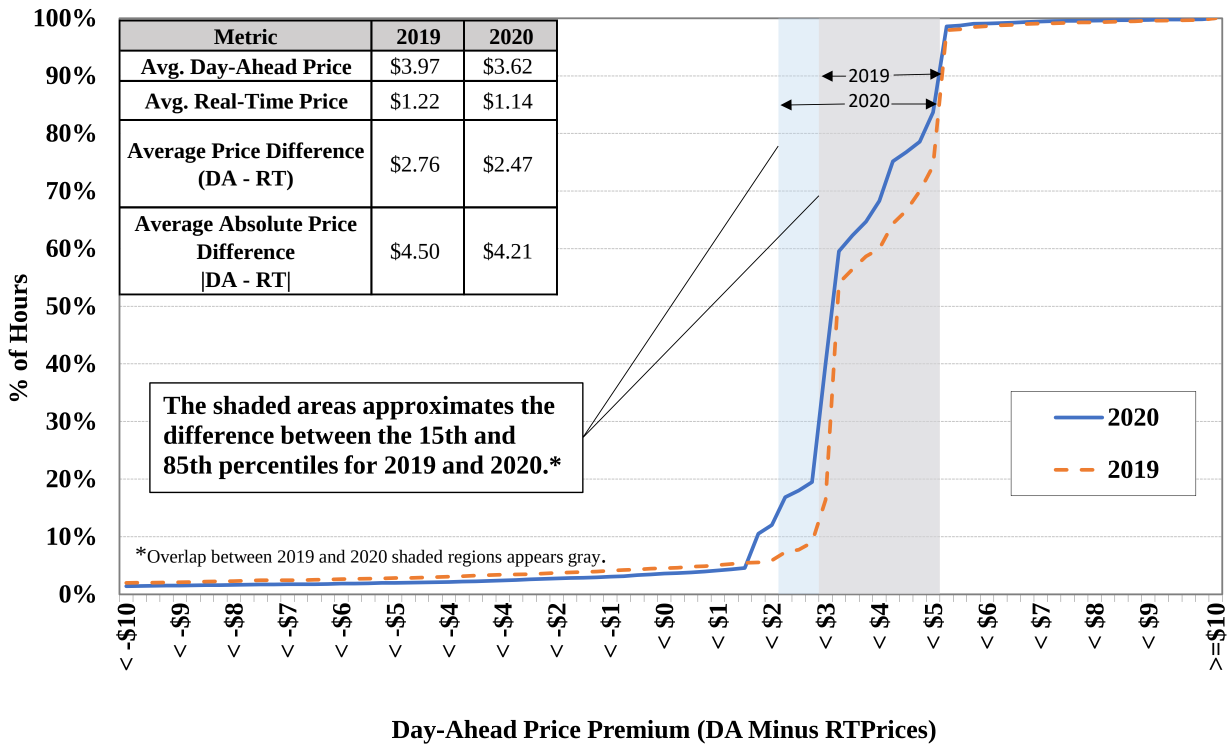
256 The NYISO introduced the New York City locational reserve region with its own explicit reserve requirements at the end of June 2019. The charts of New York City day-ahead reserve price premiums show the distributions for the period July through December, months when the new reserve requirements were fully in effect in 2019.

Figure A-16: Day-Ahead Premiums for 30-Minute Reserves in West New York
2019 – 2020



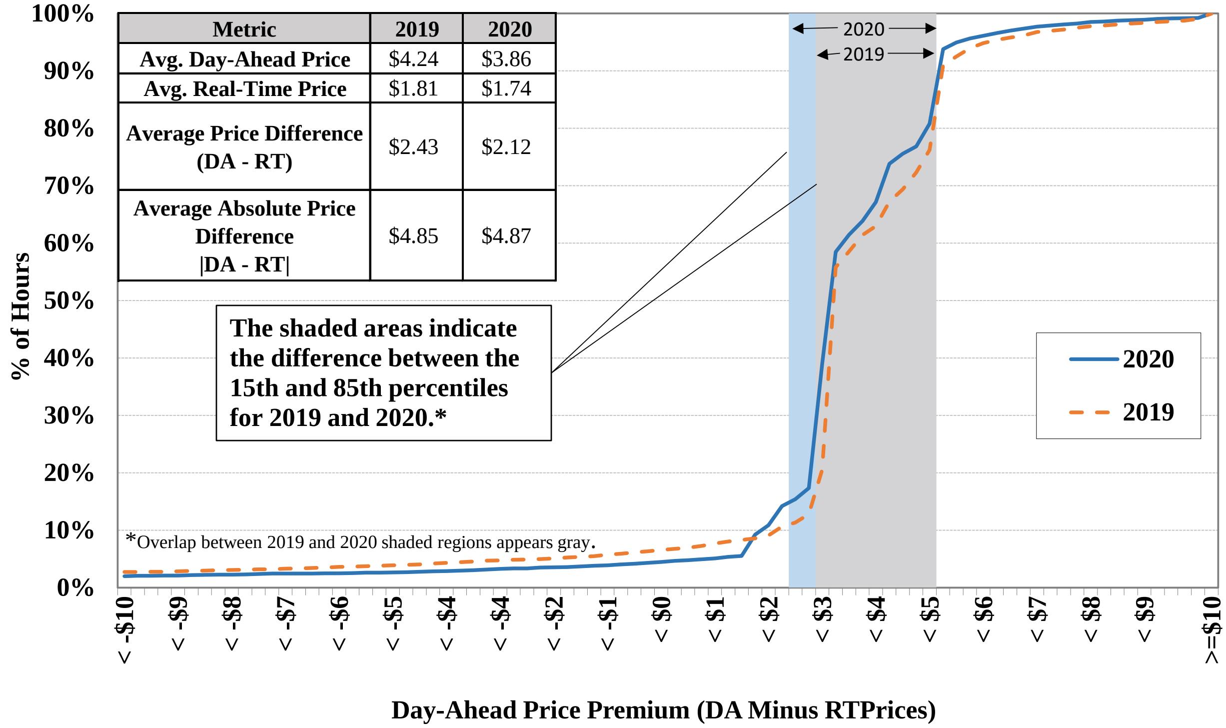
Metric	2019	2020
Avg. Day-Ahead Price	$3.62	$3.09
Avg. Real-Time Price	$0.02	$0.13
Average Price Difference (DA - RT)	$3.61	$2.96
Average Absolute Price Difference |DA - RT|	$3.62	$3.14

Figure A-17: Day-Ahead Premiums for 10-Minute Spinning Reserves in West New York
2019 - 2020



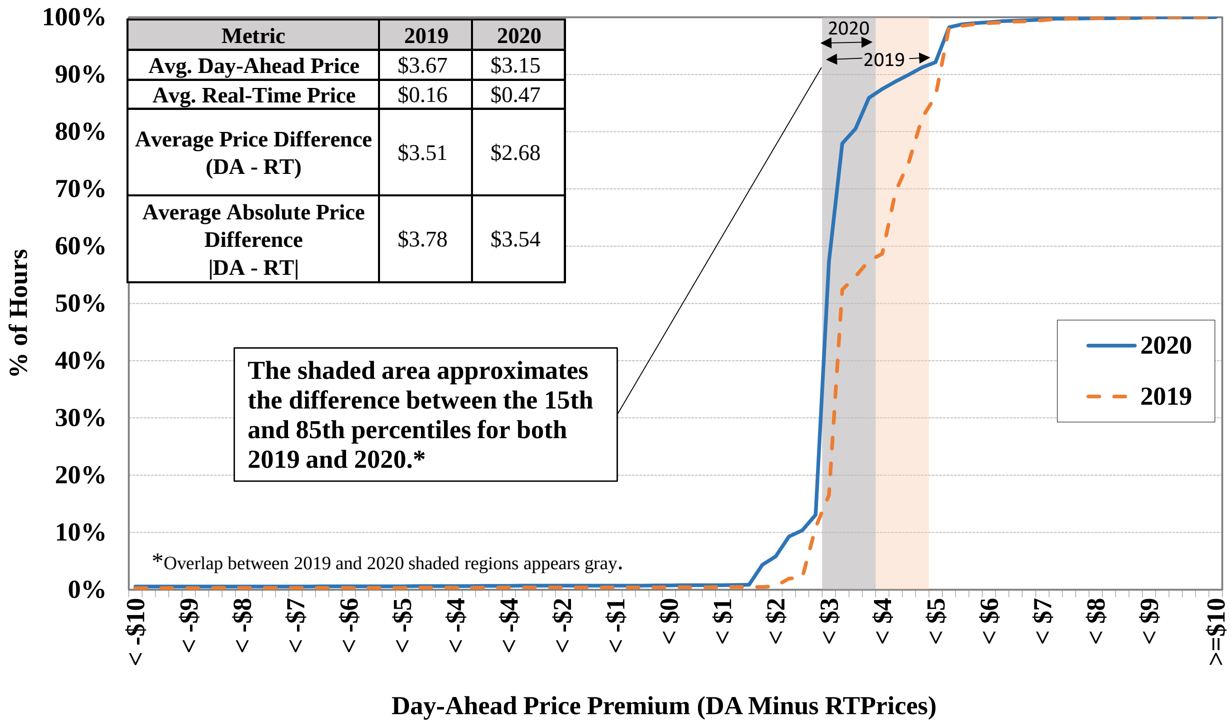
Metric	2019	2020
Avg. Day-Ahead Price	$3.97	$3.62
Avg. Real-Time Price	$1.22	$1.14
Average Price Difference (DA - RT)	$2.76	$2.47
Average Absolute Price Difference |DA - RT|	$4.50	$4.21

Figure A-18: Day-Ahead Premiums for 10-Minute Spinning Reserves in East New York
2019 – 2020



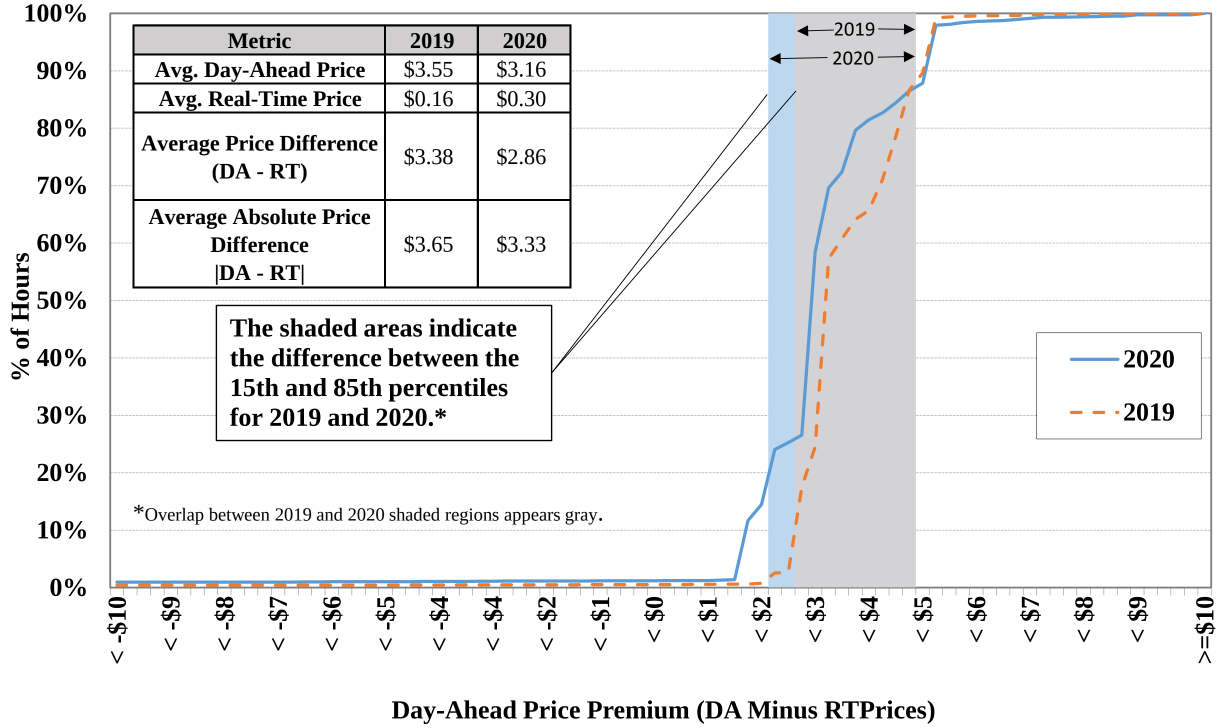
Metric	2019	2020
Avg. Day-Ahead Price	$4.24	$3.86
Avg. Real-Time Price	$1.81	$1.74
Average Price Difference (DA - RT)	$2.43	$2.12
Average Absolute Price Difference |DA - RT|	$4.85	$4.87

Figure A-19: Day-Ahead Premiums for 10-Minute Non-Spin Reserves in East New York
2019 – 2020



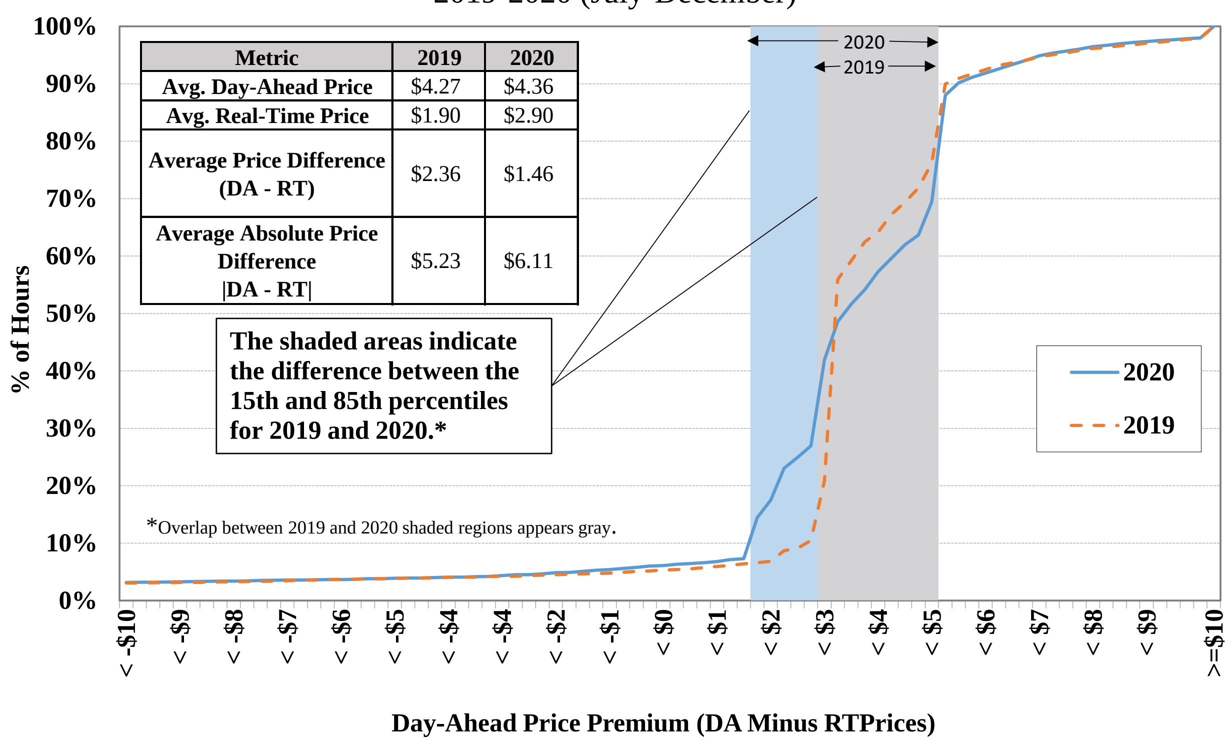
Metric	2019	2020
Avg. Day-Ahead Price	$3.67	$3.15
Avg. Real-Time Price	$0.16	$0.47
Average Price Difference (DA - RT)	$3.51	$2.68
Average Absolute Price Difference |DA - RT|	$3.78	$3.54

Figure A-20: Day-Ahead Premiums for 30-Minute Reserves in New York City
2019-2020 (July-December)



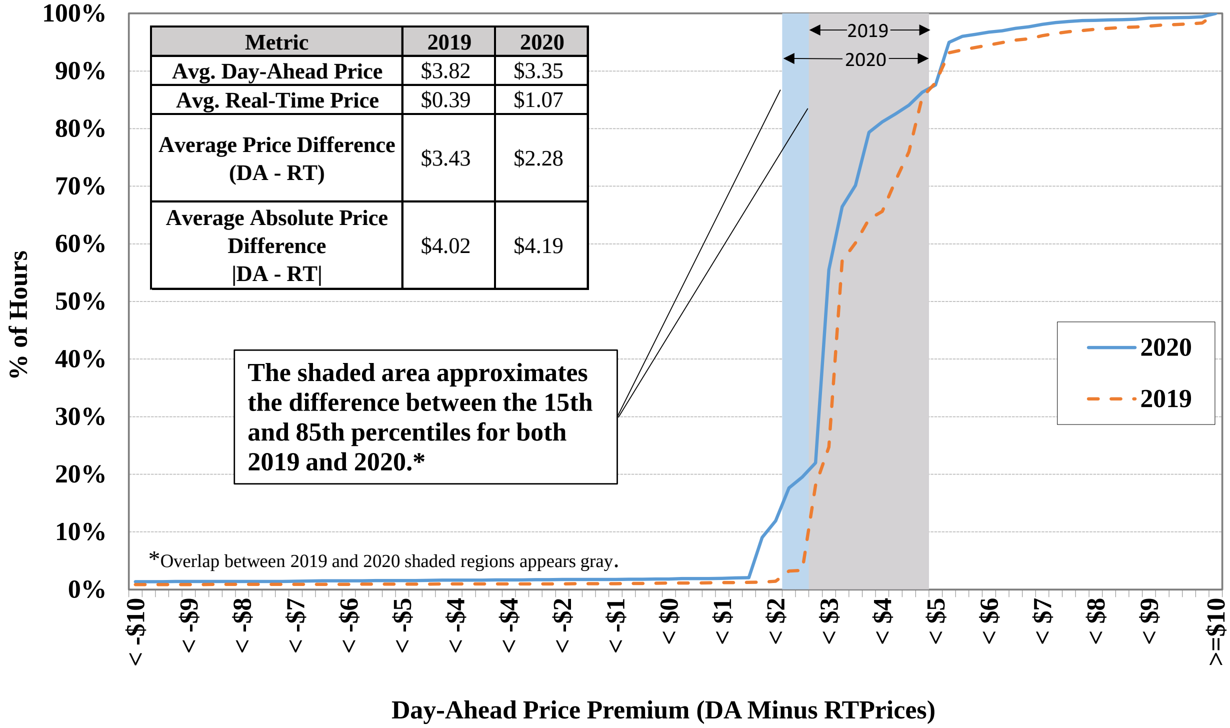
Metric	2019	2020
Avg. Day-Ahead Price	$3.55	$3.16
Avg. Real-Time Price	$0.16	$0.30
Average Price Difference (DA - RT)	$3.38	$2.86
Average Absolute Price Difference |DA - RT|	$3.65	$3.33

Figure A-21: Day-Ahead Premiums for 10-Minute Spinning Reserves in New York City
2019-2020 (July-December)



Metric	2019	2020
Avg. Day-Ahead Price	$4.27	$4.36
Avg. Real-Time Price	$1.90	$2.90
Average Price Difference (DA - RT)	$2.36	$1.46
Average Absolute Price Difference |DA - RT|	$5.23	$6.11

Figure A-22: Day-Ahead Premiums for 10-Minute Non-Spin Reserves in New York City
2019-2020 (July-December)



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 2020, for most reserve products, the majority of DA reserve price premiums remain in a relatively small band between about $2 and $5. In addition, with the exception of East and New York City 10-minute spinning, there was an increase in the frequency of smaller premiums, just greater than $1.75 but that lay outside of the shaded 85th percentile region. The shape of the distribution in the extreme tails, where the day-ahead prices were much larger or smaller than real-time prices, was similar in 2020 due to low opportunity costs and few severe unexpected RT reserve events relative to the DA forecasts.

- The average spread between DA and RT reserve prices widened slightly in 2020 in most regions, with an increase in the prevalence of smaller premiums, while the relative volatility in the spread (as measured by the average absolute difference between the DA and RT prices) either fell slightly or was very similar from 2019 to 2020.
  - In 2020, the day-ahead reserves offers were slightly lower (relative to 2019) due to the lower opportunity costs that are associated with energy prices. Furthermore, the supply of low-cost reserves also increased due to new entry, increased participation from existing generators and fewer days of maintenance-related outages.
  - Real-time reserve prices, in general, are largely driven by prices during shortage events, whose frequency was significantly lower in 2020 because of lower load levels.
  - Overall, 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.

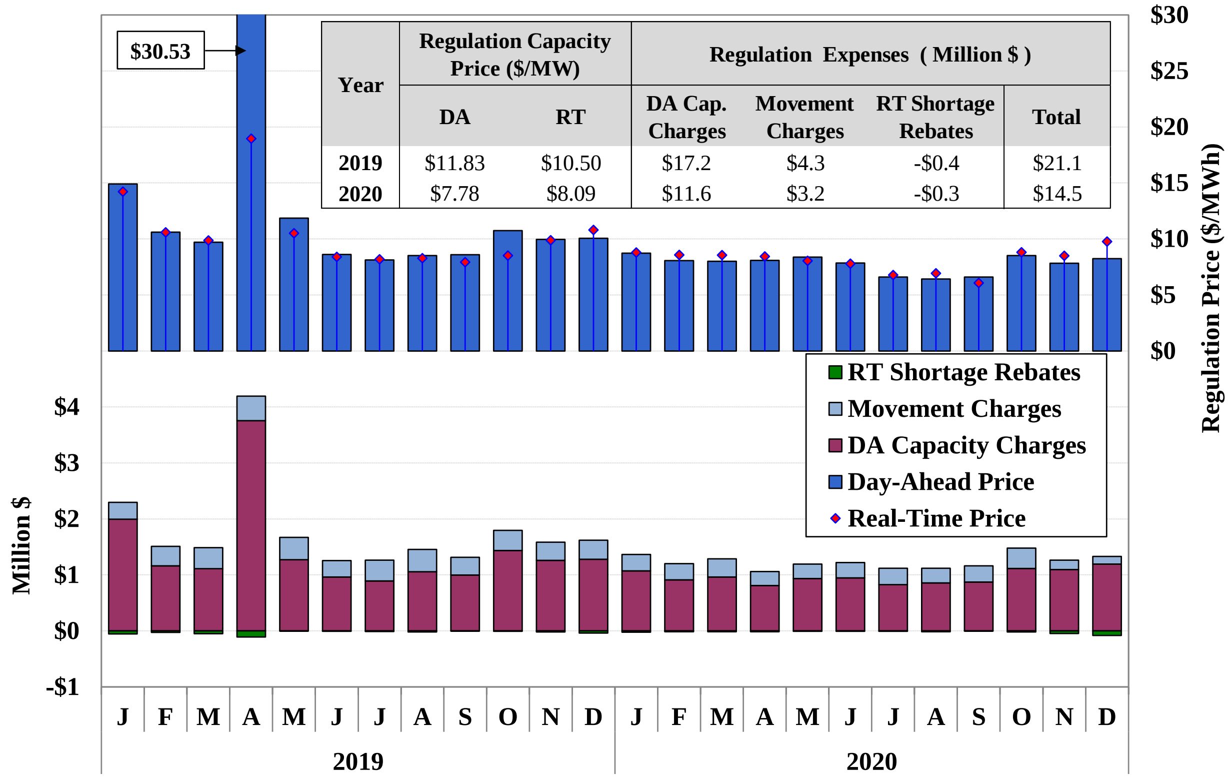
I. Regulation Market Performance

Figure A-23 – Regulation Prices and Expenses

Figure A-23 shows the regulation prices and expenses in each month of 2019 and 2020. 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, 2019-2020



Year	Regulation Capacity Price ($/MW)		Regulation Expenses (Million $)			
	DA	RT	DA Cap. Charges	Movement Charges	RT Shortage Rebates	Total
2019	$11.83	$10.50	$17.2	$4.3	-$0.4	$21.1
2020	$7.78	$8.09	$11.6	$3.2	-$0.3	$14.5

Key Observations: Regulation Market Performance

- Consistent with the fall in energy prices in 2020, average regulation capacity prices in real-time and day-ahead prices declined year-over-year by 18 percent and 34 percent, respectively.
  - The steeper reduction in the day-ahead price was a consequence of the price impact of the April 2019 capacity shortages which affected day-ahead premiums more severely (see Subsection H).
- Regulation expenses decreased by 31 percent in 2020 primarily due to a steep reduction in costs associated with the DA Capacity Charges ($5.58 million reduction).

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.* [257]

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.

[257] 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.

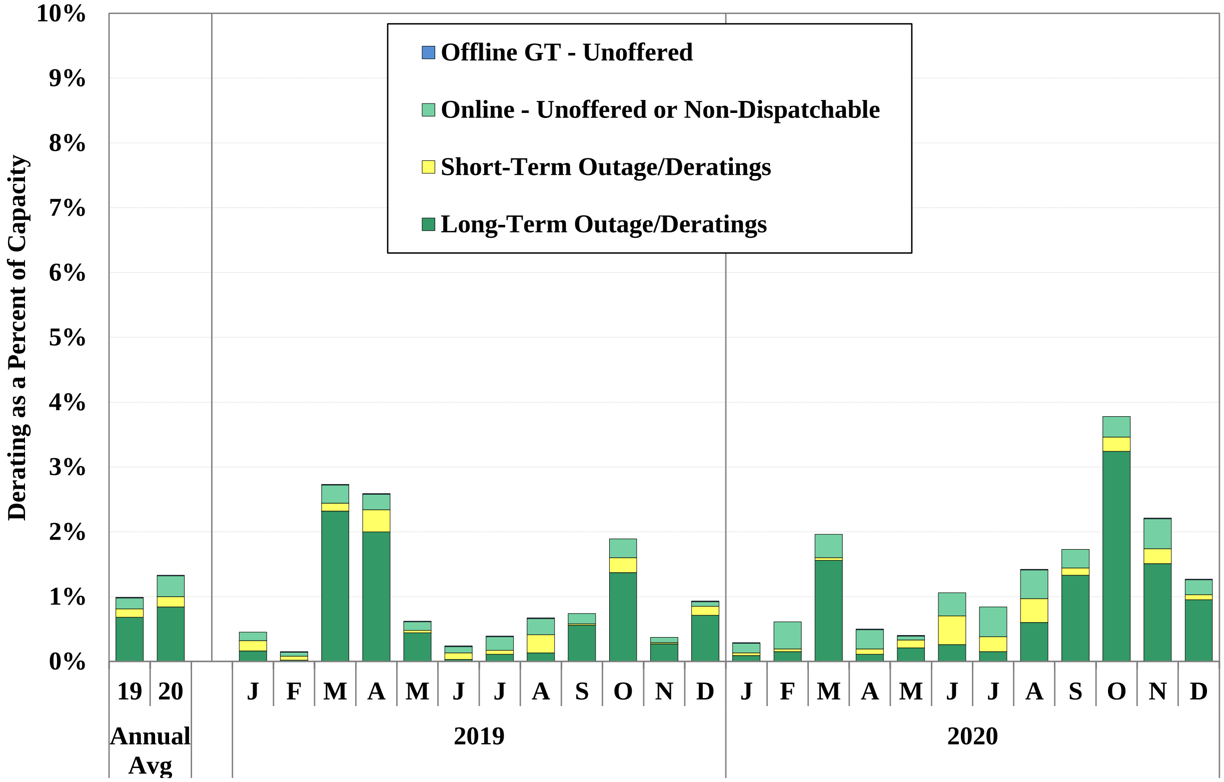
We also focus on economic capacity, since derated and unoffered capacity that is uneconomic does not raise prices above competitive levels and, therefore, is not an indicator of potential withholding.

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.[258] 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.[259] Quick-start units that were economic to commit must have been economic at both forecast RTC prices and settlement RTD prices.[260]

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 2019 and 2020.

Figure A-24: Unoffered Economic Capacity by Month in NYCA
2019 – 2020



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

259 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.

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

Figure A-25: Unoffered Economic Capacity by Month in East New York
2019 - 2020

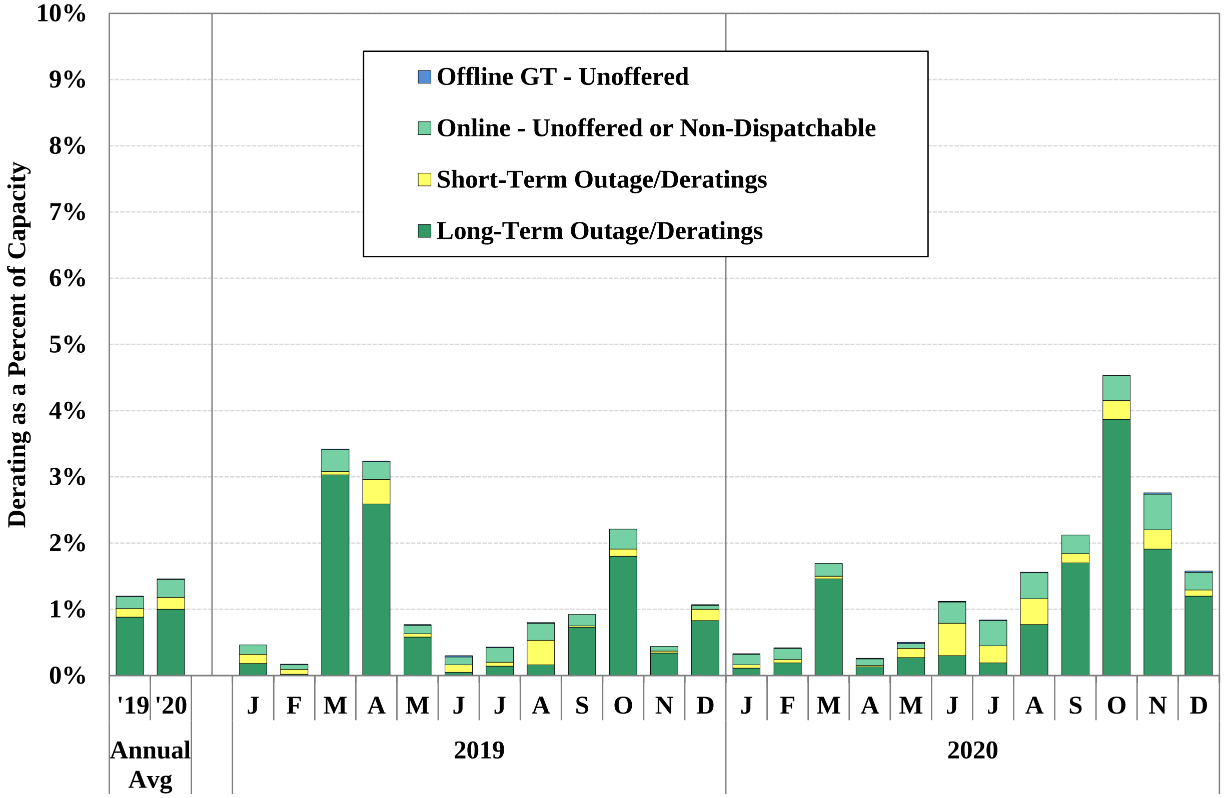


Figure A-26 & Figure A-27: Unoffered Economic Capacity by Load Level & Portfolio Size

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
2019 – 2020

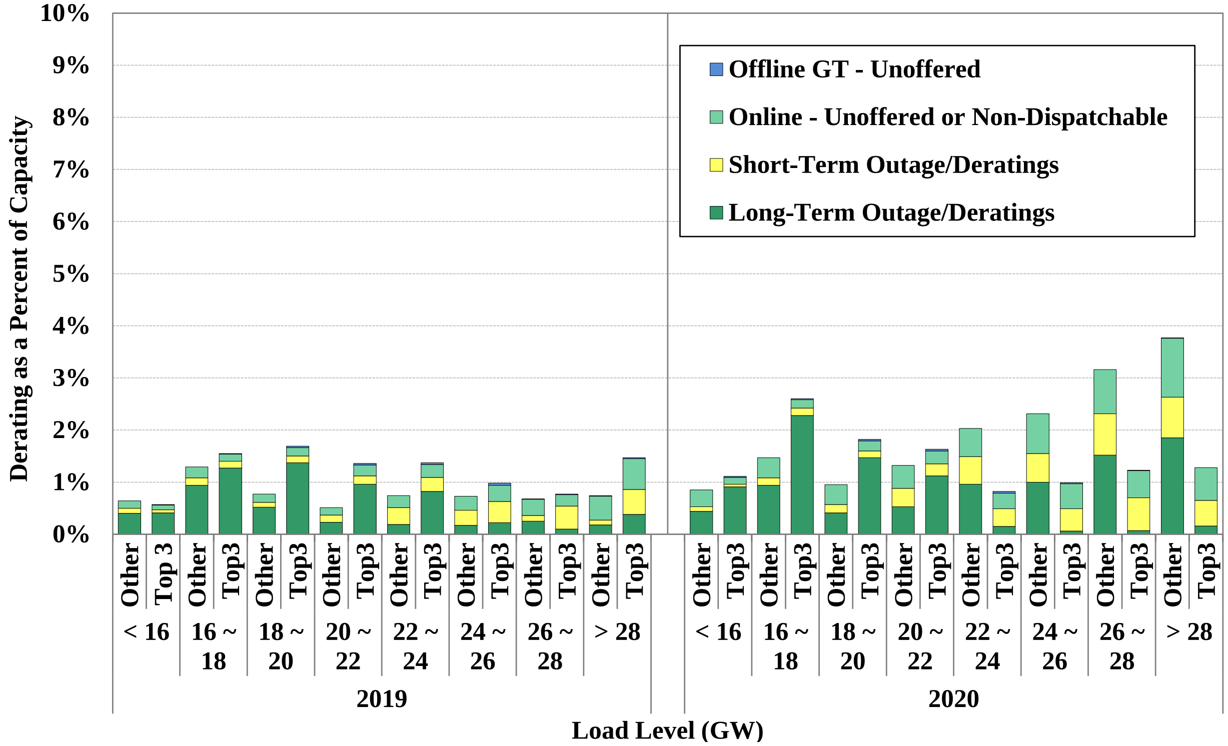
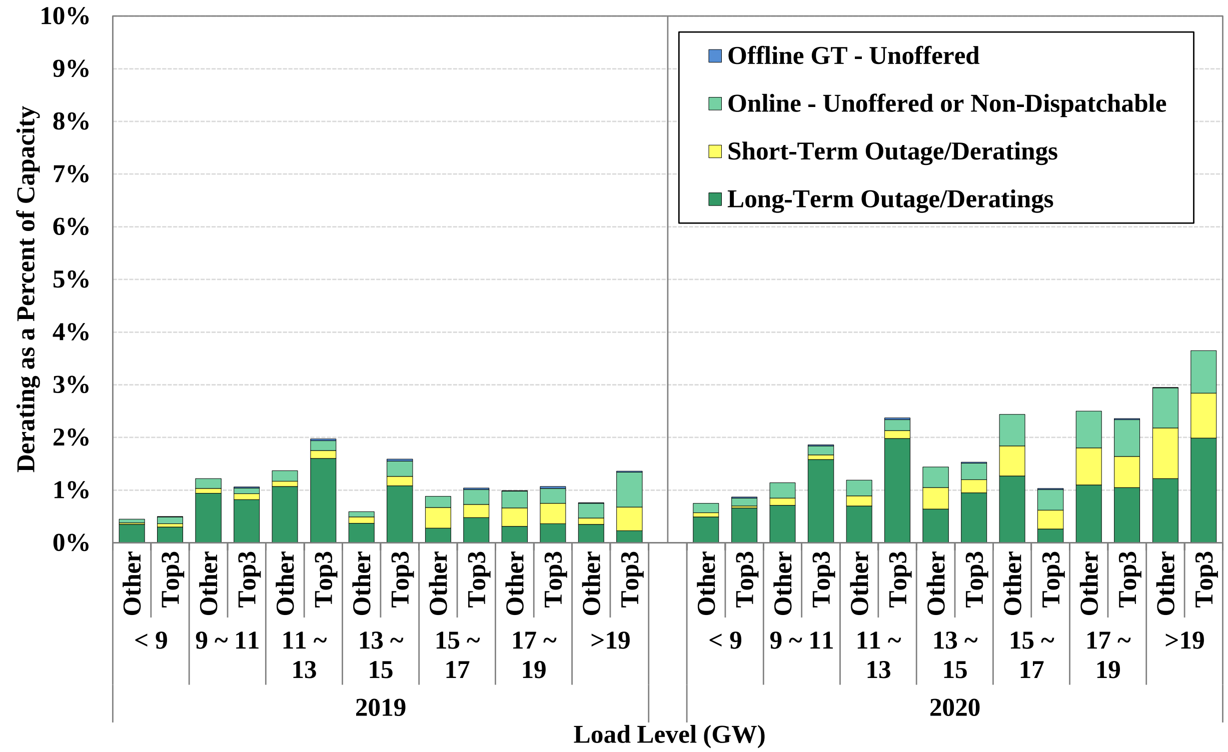


Figure A-27: Unoffered Economic Capacity by Supplier by Load Level in East New York
2019 – 2020



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 1.3 percent of total DMNC in NYCA, and 1.5 percent in Eastern New York in 2020, which was higher than 2019 levels.
  - Derated and unoffered economic capacity was mostly attributable to long-term maintenance (making up 63 percent of the total in NYCA and 68 percent in Eastern New York in 2020).
    - Most of this economic capacity was scheduled for long-term maintenance during shoulder months as would be expected. In prior years, many generators scheduled maintenance outages during the Spring (i.e., March through May) and/or Fall (i.e. September through November) shoulder months. However, in 2020, given the pandemic-related restrictions (that resulted in constraints on staffing and travel, among others) during March of 2020, many seasonal outages were deferred to the Fall shoulder months.
      - The proportion of unoffered economic capacity due to long-term outages in 2019 during Spring and Fall months was roughly 60 percent and 27 percent, respectively. In contrast, in 2020, only 19 percent of total unoffered economic capacity from long-term outages occurred during the Spring and 60 percent occurred in the Fall months.
    - The largest three suppliers in Eastern New York had only small totals of long-term outages during the highest load hours.
- Although economic capacity on outage/deratings was low overall during the summer of 2020, it was higher than it was during the summer of 2019 for a number of reasons:
  - At least one baseload unit was forced to delay normal spring seasonal outage to June.
  - Multiple units experienced unanticipated forced outages while operating resulting in an increase of short-term outages.
  - A significant forced outage caused one otherwise economic baseload unit to be offline during most of the summer.
- 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.
  - This is especially true during periods of very low gas prices drop (for instance, during 2020 shoulder months). Reference levels for efficient combined cycle units in 2020 were below $10 per MWh at the upper end of their operating range at times.

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.[261, 262] 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.[263] 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

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261 The method of calculating reference levels is described in NYISO Market Services Tariff, Attachment H – NYISO Market Monitoring Plan-Market Mitigation Measures, Section 23.3.1.4. 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.

262 Due to the Fuel Cost Adjustment (FCA) functionality, a generator's reference level can 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.

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

physical withholding, we examine the broad patterns of output gap in New York State and Eastern New York, and we address the relationship of the output gap to the market demand level and participant size.

The following four figures show the output gap using three thresholds: the state-wide mitigation threshold (i.e., the standard conduct threshold used for mitigation outside New York City), which is the lower of $100 per MWh or 300 percent of a generator's reference level; and two additional lower thresholds: Lower Threshold 1 is 25 percent of a generator's reference level, and Lower Threshold 2 is 100 percent of a generator's reference level. The two lower thresholds are included to assess whether there may have been abuse of market power that does not trigger the thresholds specified in the tariff for imposition of mitigation measures by the ISO. However, because there is uncertainty in the estimation of the marginal costs of individual units, results based on lower thresholds are more likely to flag behavior that is actually competitive.

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

Figure A-28: Output Gap by Month in New York State
2019 – 2020

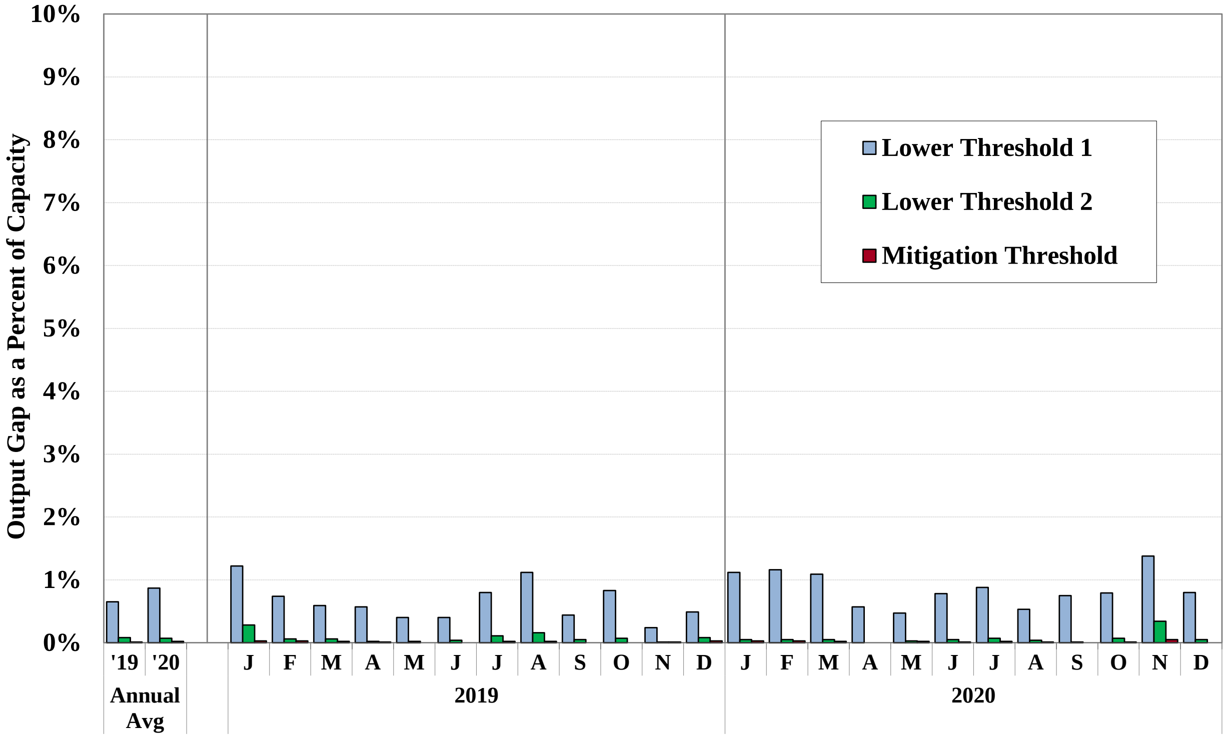


Figure A-29: Output Gap by Month in East New York
2019 - 2020

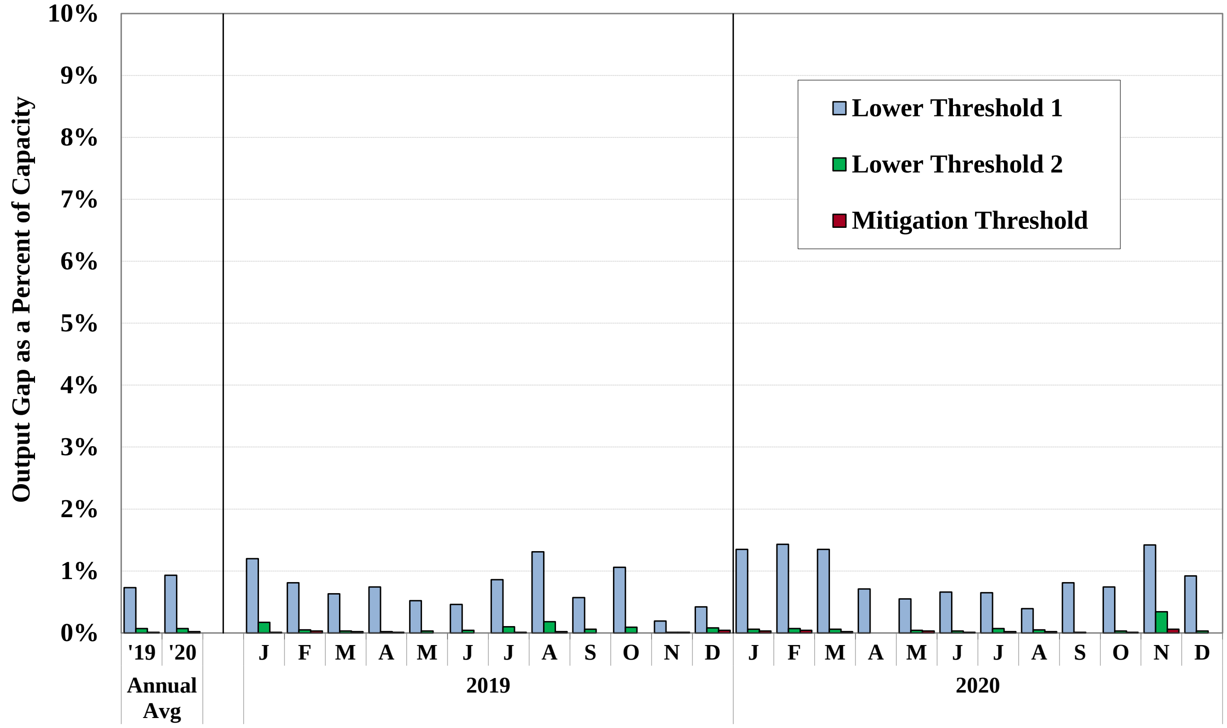


Figure A-30: Output Gap by Supplier by Load Level in New York State
2020

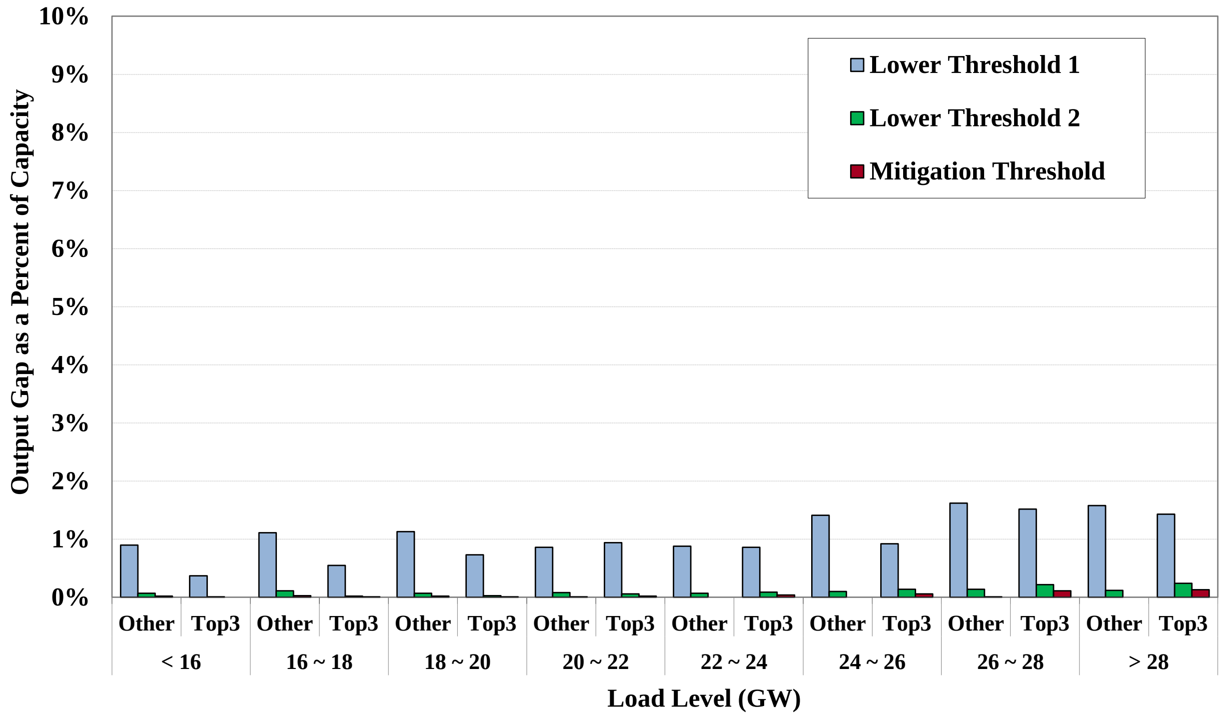
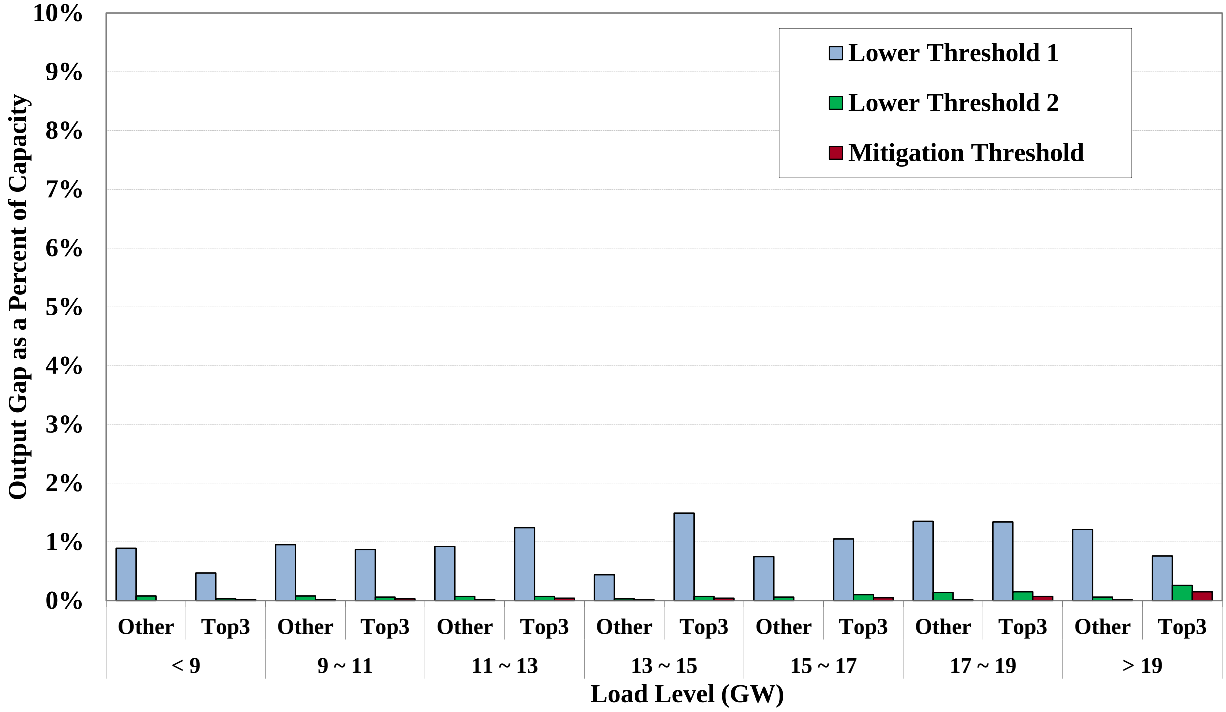


Figure A-31: Output Gap by Supplier by Load Level in East New York
2020



Key Observations: Economic Withholding – Generator Output Gap

- The amount of output gap averaged 0.02 percent of total capacity at the mitigation threshold, and roughly 0.87 percent at the lowest threshold evaluated (i.e., 25 percent) in 2020 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:
  - 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 situations, the Reference Levels may not reflect the full marginal cost of operating individual units.
  - Additionally, many combined cycle units do not have means to reflect in their Reference Levels the operational constraints and additional costs associated with operating the duct-firing portion of their output range. Consequently, many of these units tend to offer inflexibly in real-time, which may result in small amounts of output gap estimates for the capacity associated with the duct burner.
- Overall, the output gap level in 2020 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.[264] 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.[265] 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 New York City.[266] 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.[267]

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

265 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.

266 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.

267 See NYISO Market Services Tariff, Section 23.3.1.2.3.

While uncommon, a generator can be mitigated initially in the day-ahead or real-time market and unmitigated after consultation with the NYISO.[268] 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.[269]
- 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 2019 and 2020. These figures do not include guarantee payment mitigation that occurs in the settlement system.

The bars in the upper panel of the figures indicate the percent of hours when incremental energy offer mitigation was imposed on one or more units in each category, while the bars in the lower panel indicate the average amount of capacity mitigated in hours when mitigation occurred (as well as the portion that was unmitigated). Mitigated quantities are shown separately for the flexible output ranges of units (i.e. Incremental Energy) and the non-flexible portions (i.e. MinGen).[270] 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.

268 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 un-mitigation.

269 The hierarchy of information that is used to calculate reference levels is provided in NYISO Market Services Tariff, Section 23.3.1.4. 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.

270 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-32: Summary of Day-Ahead Mitigation
2019 – 2020

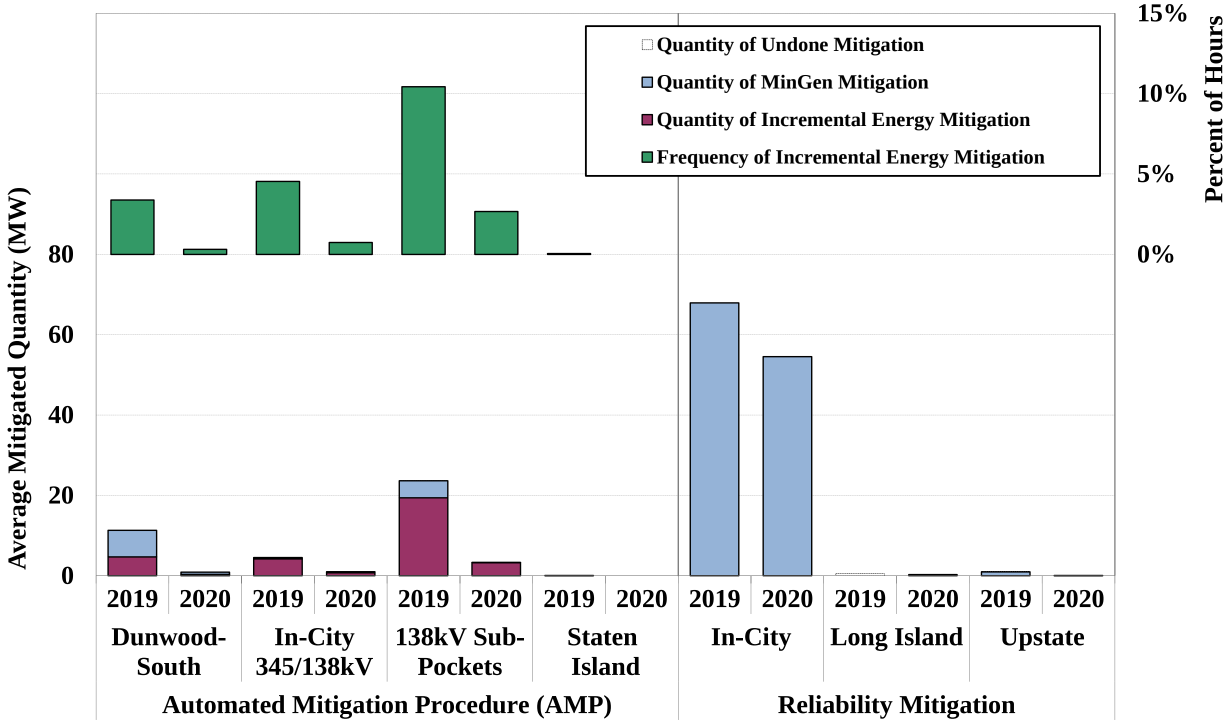
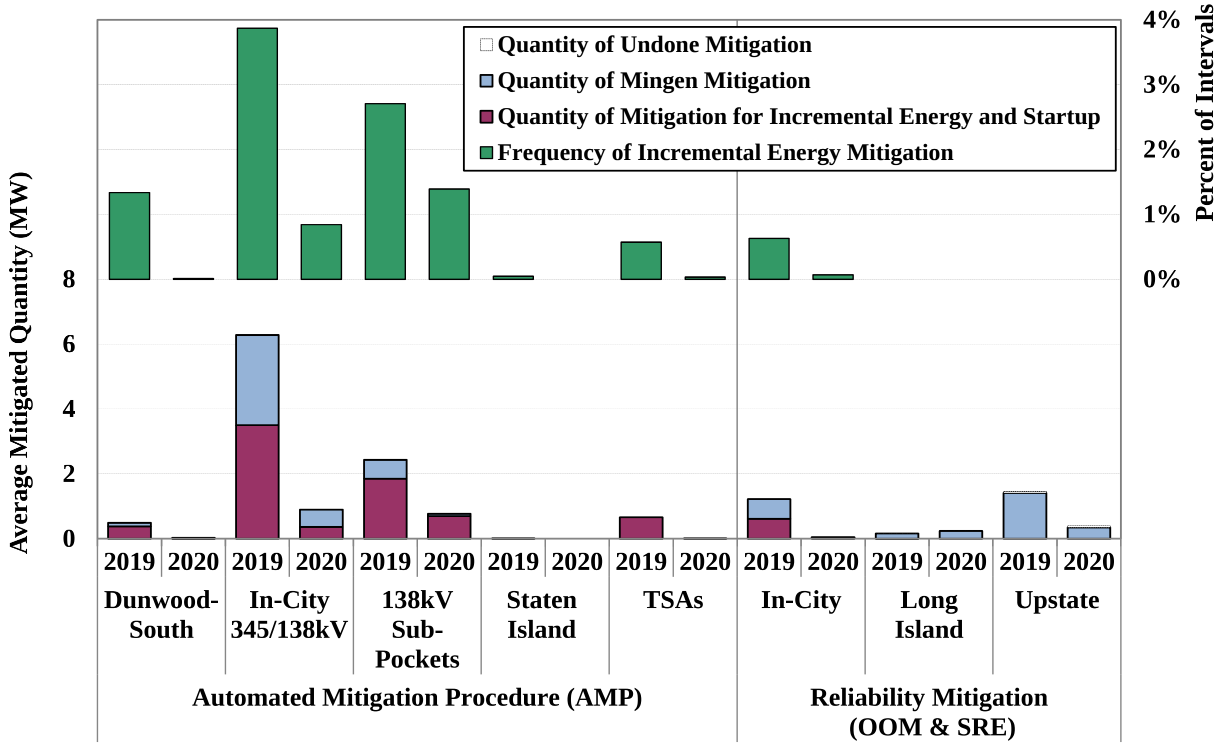


Figure A-33: Summary of Real-Time Mitigation
2019 – 2020



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 in 2020 fell by 20 percent from 2019.
  - Local reliability (i.e., DARU and LRR) mitigation in New York City (which accounted for 91 percent of day-ahead mitigation in 2020) fell because of less frequent load conditions that required the reliability commitments of New York City steam units.[271]
    - Historically, the local reserve requirements for most load pockets used a single daily capacity requirement that was based on the daily peak load expectations. Beginning July 30, 2020, the NYISO determined these capacity requirements on an hourly basis for most load pockets, which helped reduce the frequency of reliability commitments, especially in the off peak hours.
    - These mitigations limited guarantee payment uplift but did not affect LBMPs.
  - Reliability mitigation in the upstate regions declined from 2019 levels and was de minimis in 2020. In recent years, much of the upstate reliability mitigation has been occurred during extreme cold weather events. The total reliability mitigation thus fell markedly in the absence of such extreme weather in 2020.
  - AMP mitigation was very infrequent and accounted for just 9 percent of day-ahead mitigation. In 2020, AMP mitigation was down significantly from 2019 (falling 76 to 92 percent year-over-year) in all load pockets despite lower Load Pocket Thresholds.
    - AMP mitigation only applies when there is an active constraint. The significant reduction in congestion in New York City load pockets during 2020 resulted in fewer instances where AMP could apply (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.

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271 See Section XII for our recommendation (#2017-1) to model local reliability requirements in NYC load pockets.

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 2019 and 2020 on a monthly basis and an annual basis. Quantities offered are shown for:

- 10-minute spinning reserves in Western New York,
- 10-minute spinning reserves in Eastern New York,
- 10-minute non-spinning reserves in Eastern New York,[272]
- 30-minute operating reserves in NYCA,[273] and
- Regulation.[274]

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.

272 This category only includes the reserve capacity that can be used to satisfy the 10-minute non-spinning reserve requirements but not 10-minute spinning reserve requirements.

273 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.

274 Regulation offers shown are a composite of the offered capacity and movement.

Figure A-34: Summary of West 10-Minute Spinning Reserves Offers
Day-Ahead Market, 2019 – 2020

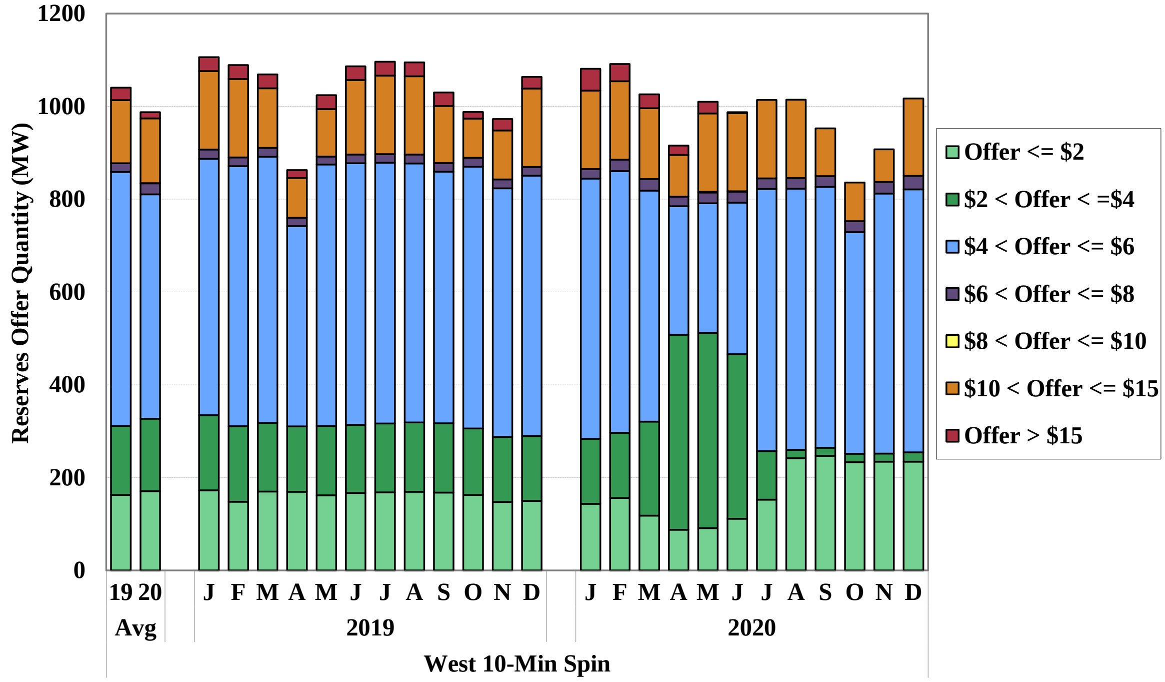

Figure A-35: Summary of East 10-Minute Spinning Reserves Offers
Day-Ahead Market, 2019 – 2020

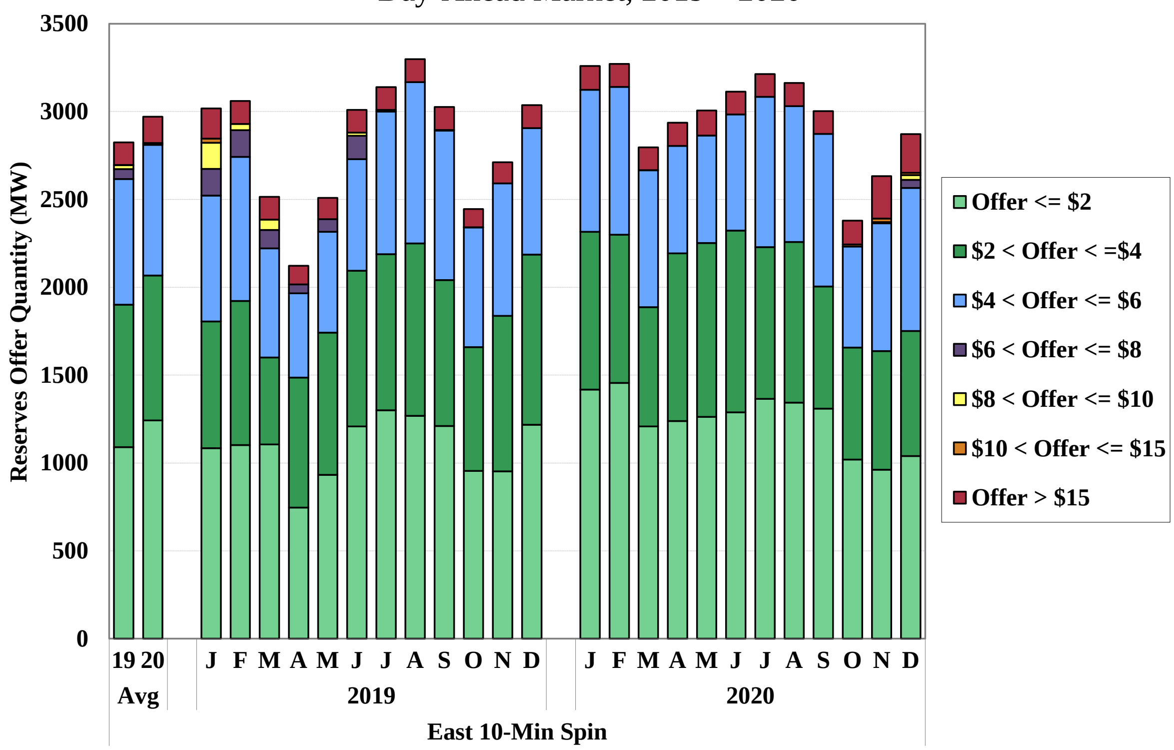

Figure A-36: Summary of East 10-Minute Non-Spin Reserves Offers
Day-Ahead Market, 2019 – 2020

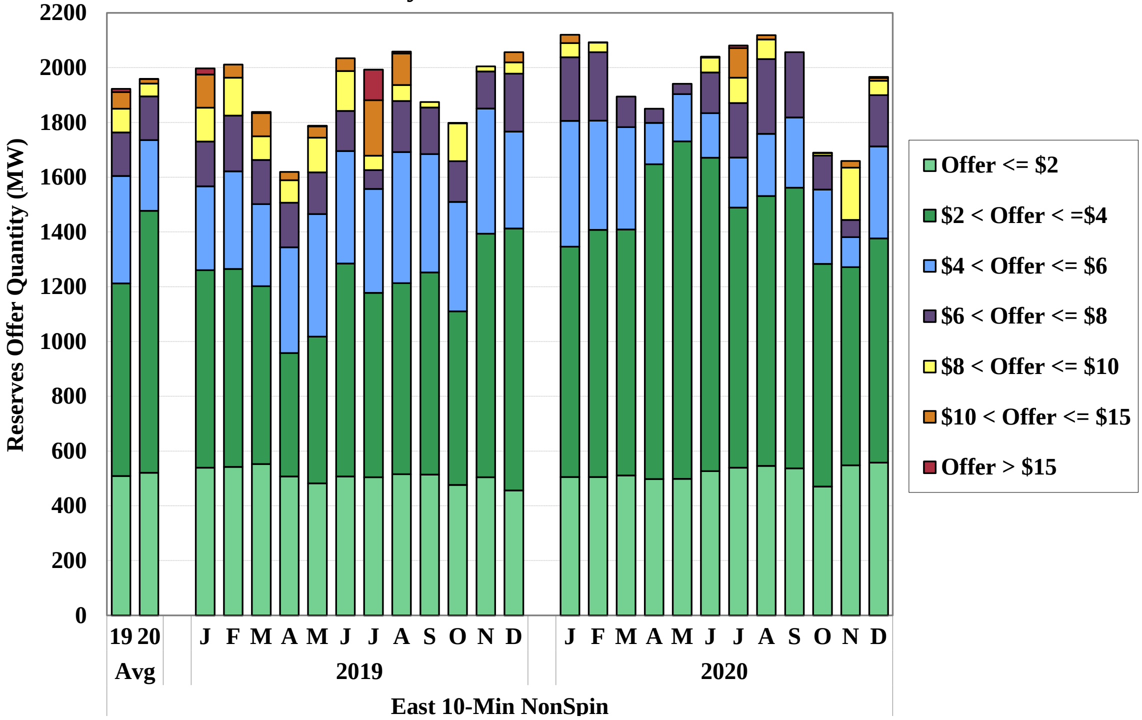

Figure A-37: Summary of NYCA 30-Minute Operating Reserves Offers
Excluding 10-minute, Day-Ahead Market, 2019 – 2020

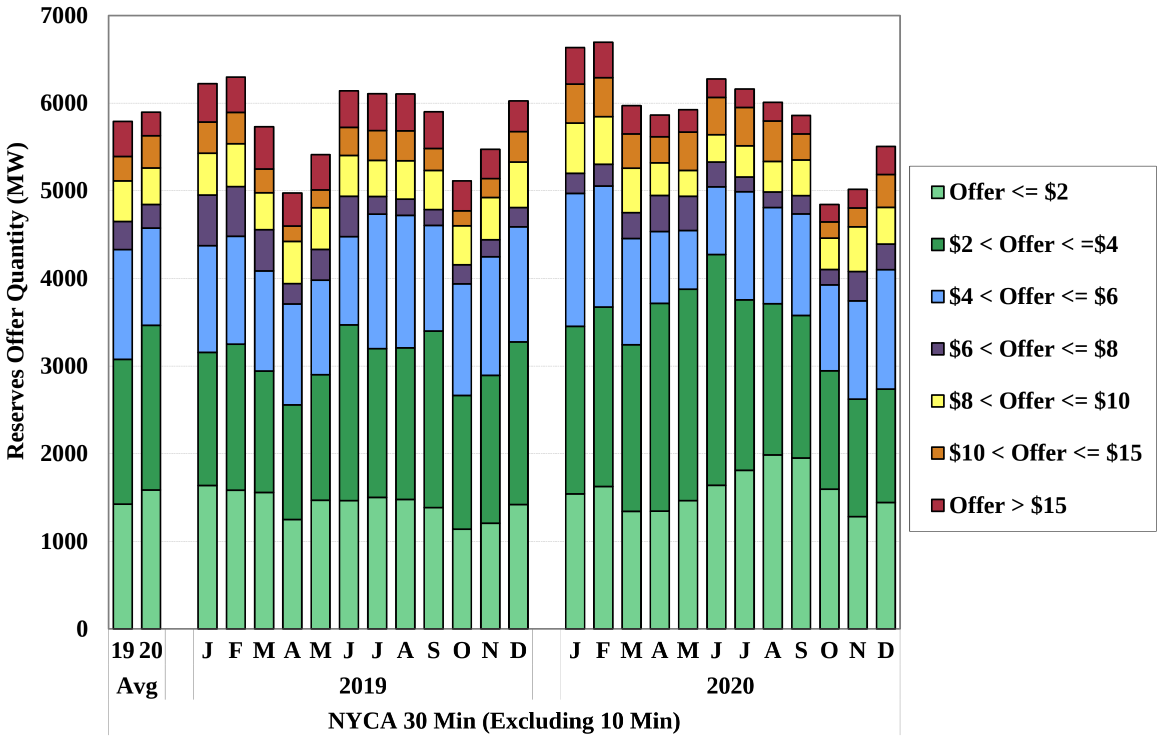

Figure A-38: Summary of Regulation Capacity Offers
Day-Ahead Market, 2019 – 2020

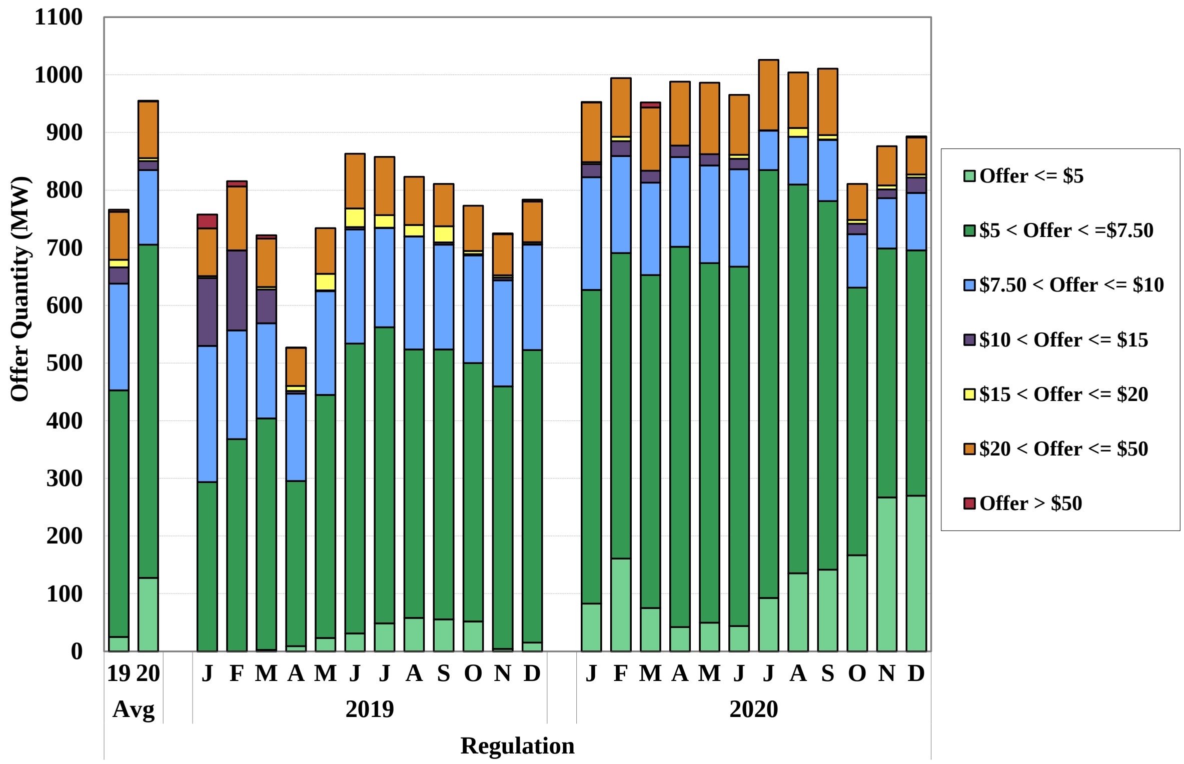

Figure A-39 to Figure A-40: Day-Ahead Reserve Offers That Satisfy NYCA 30-Minute Requirement and NYC Reserve Requirement

Figure A-39 summarizes reserve offers that can satisfy NYCA 30-minute operating reserve requirement in each quarter of 2018 to 2020 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, 2018 – 2020

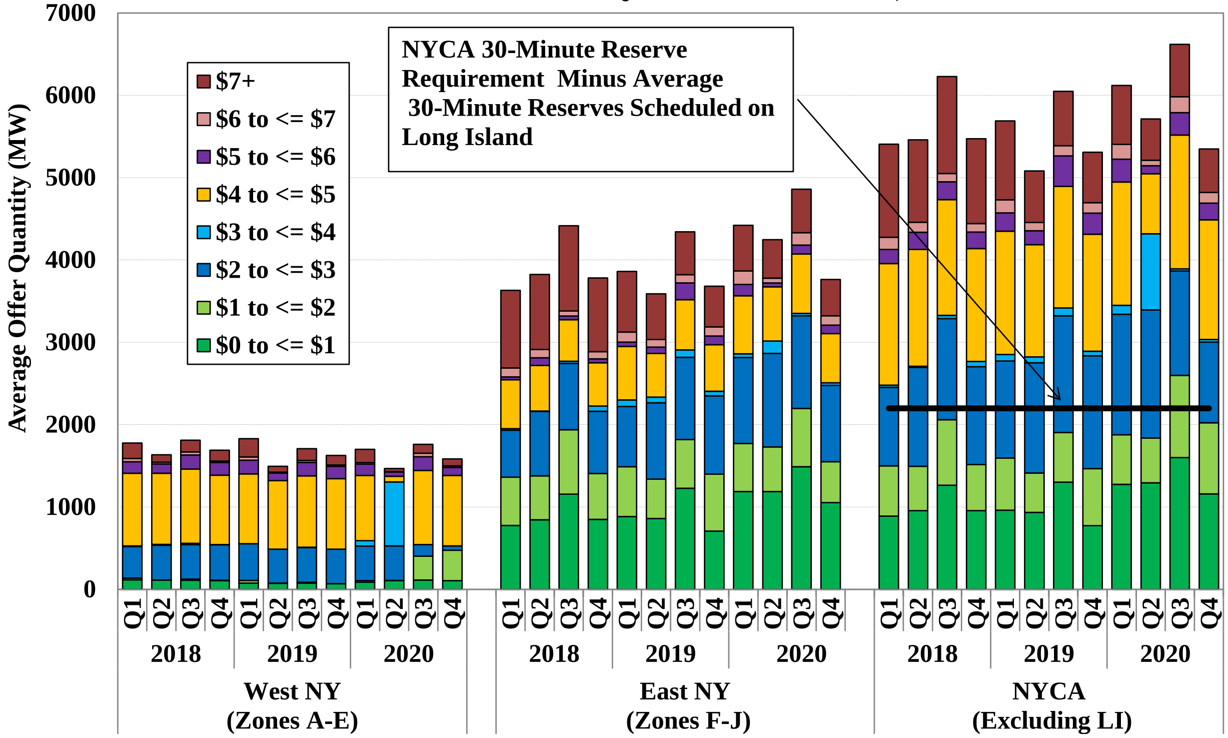

Figure A-40: Day-Ahead Reserve Offers that Satisfy NYC Reserve Requirement
Committed and Available Offline Quick-Start Resources, 2018-2020

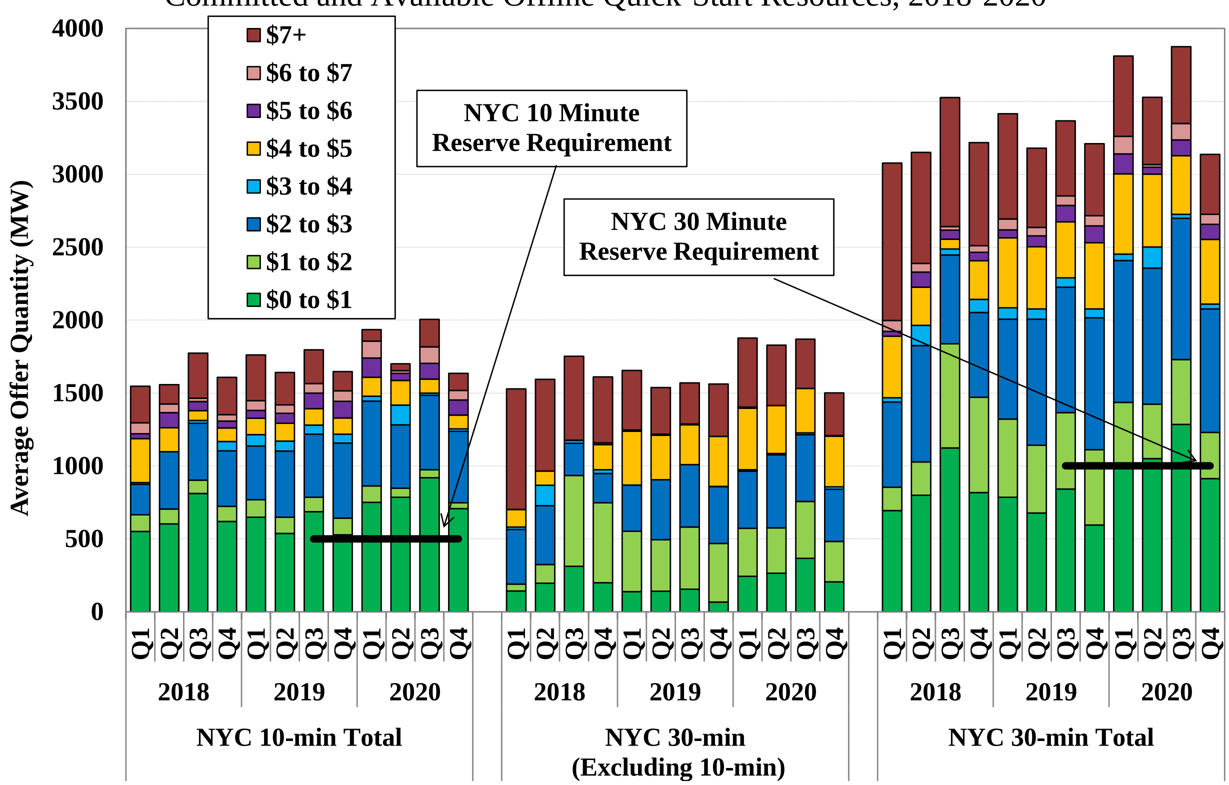

Figure A-40 summarizes offers that can satisfy the new NYC reserves requirement and shows NYC generator offers for 10- and 30-minute reserves from committed resources and available offline quick-start resources. The information is provided by quarter from 2018 and extending through 2020 for comparative purposes even though the NYC requirement was not implemented until 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-39, 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

- New entry and exit of generators, limited or deferred generator maintenance, low load and low gas price volatility contributed to overall changes in offer quantities and lower-priced ancillary service offers in 2020.
  - Limited or deferred maintenance due to the Covid-19 pandemic-related constraints on supply of labor and parts allowed for increased participation from some generators for parts of 2020. The entry and exit of generators that offered ancillary services likely resulted in more persistent changes to the offer quantities.
  - Lower load and less gas price volatility likely decreased the potential risks of providing reserves, thus resulting in lower-priced offers. Furthermore:
    - Lower load conditions generally result in newer and more efficient units being committed, which tend to have fewer forced outages.[275] Hence, operating reserve providers face lower trip risk as the likelihood of reserves being converted to energy is lower. Some of the operating reserve providers, particularly GTs, do not perform well when responding to start-up instructions in real-time, and consequently, could face considerable trip risk.[276]
    - Lower gas price volatility reduces the potential balancing costs associated with procuring gas in real-time.
- The overall quantity of reserve services offered in three of the four reserve products (East 10-minute spinning, East 10-minute non-spinning, and NYCA 30-minute operating reserves) increased by two percent to five percent between 2019 and 2020.

[275] See Figure A-108.

[276] See Figure A-83.

  - The supply of East 10-minute non-spinning reserves increased the most in 2020 (by five percent), in part because of increased generator participation in this reserve product and reduced duration of maintenance-related outages in 2020.[277]
  - The seasonal reserve offer pattern was atypical in 2020 due to changes in generator maintenance which occurred because of Covid-19 impacts on availability of labor and parts. The reserve quantities offered in April and May 2020 did not drop as significantly as it did in prior years. The offered reserve quantities were nine percent and 38 percent higher in these months when compared to 2019. In contrast, the decrease in overall offers typical in the fall was more pronounced and extended later into the year as generators entered extended maintenance that had previously been deferred. Across the three reserve products, depending on the month, there were between three percent and 17 percent lower reserve quantities in October through December than in 2019.

- Unlike other reserve categories, West 10-minute spinning offers fell year-over-year by five percent, primarily because of the retirement of generators offering this product.

- In the West and East 10-minute spinning categories, an increase in offers in the $2-$4 range occurred between April and June, while the quantity of offers in the $4-$6 range fell. This was because of (a) lower offers from some generators that tend to offer at a higher price, and (b) increase in the offered quantity from generators that typically offered in the $2-$4 range. The change in pattern was coincident with the first months of the pandemic when the energy prices were the lowest during the year.

- The overall quantity of regulation offers from all resources rose considerably (by 25 percent) between 2019 and 2020 primarily due to increased existing generator participation and new entry. The pattern of offers in the Spring and Fall was impacted by deferred maintenance in a manner similar to other reserve products. An increase in offers in the lower ranges (less than $10 per MWh) is the result of both increased generator participation in regulation and lowering of offers in 2020. During years with lower load and fuel prices, the costs of regulating tends to decrease.[278]
  - The quantity of regulation offers in April 2020 was 88 percent higher than in 2019. While deferred maintenance was a factor for increased offers in 2020, April 2019 was particularly low 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

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277 New entrants included newer units and existing generators, which expanded participation in the reserves markets in 2020.

278 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.[279]

- *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 unit commitment relies on consistency between the day-ahead and the real-time markets. The

[279] 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.

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 2019 and in 2020 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 2019 to 2020. 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, 2019 – 2020

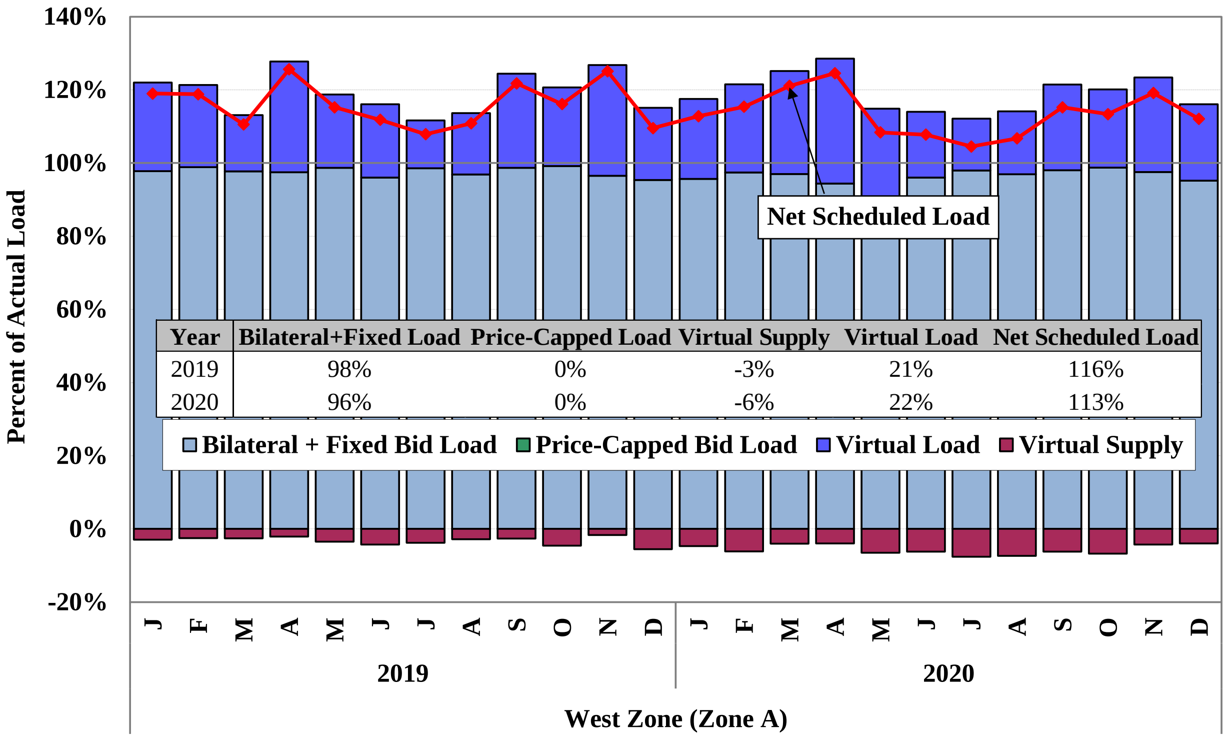


Figure A-42: Day-Ahead Load Schedules versus Actual Load in Central New York
Zones B, C, & E, 2019 – 2020

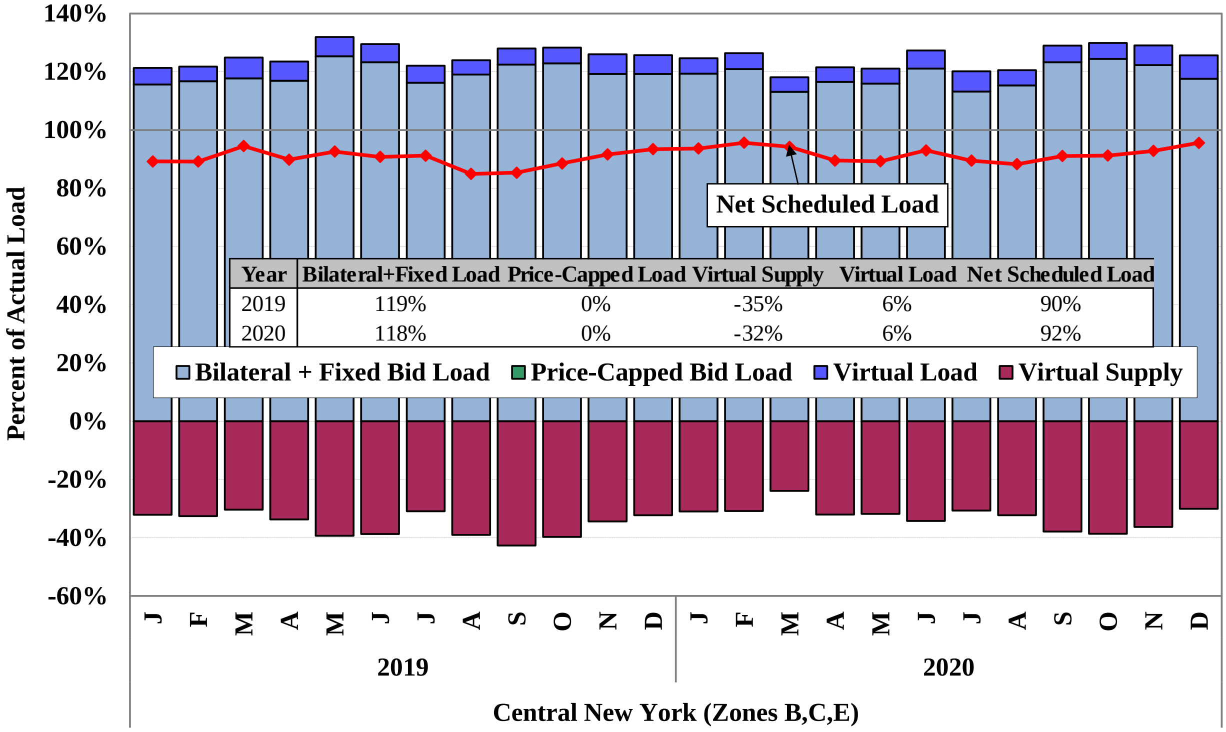


Figure A-43: Day-Ahead Load Schedules versus Actual Load in North Zone
Zone D, 2019 – 2020

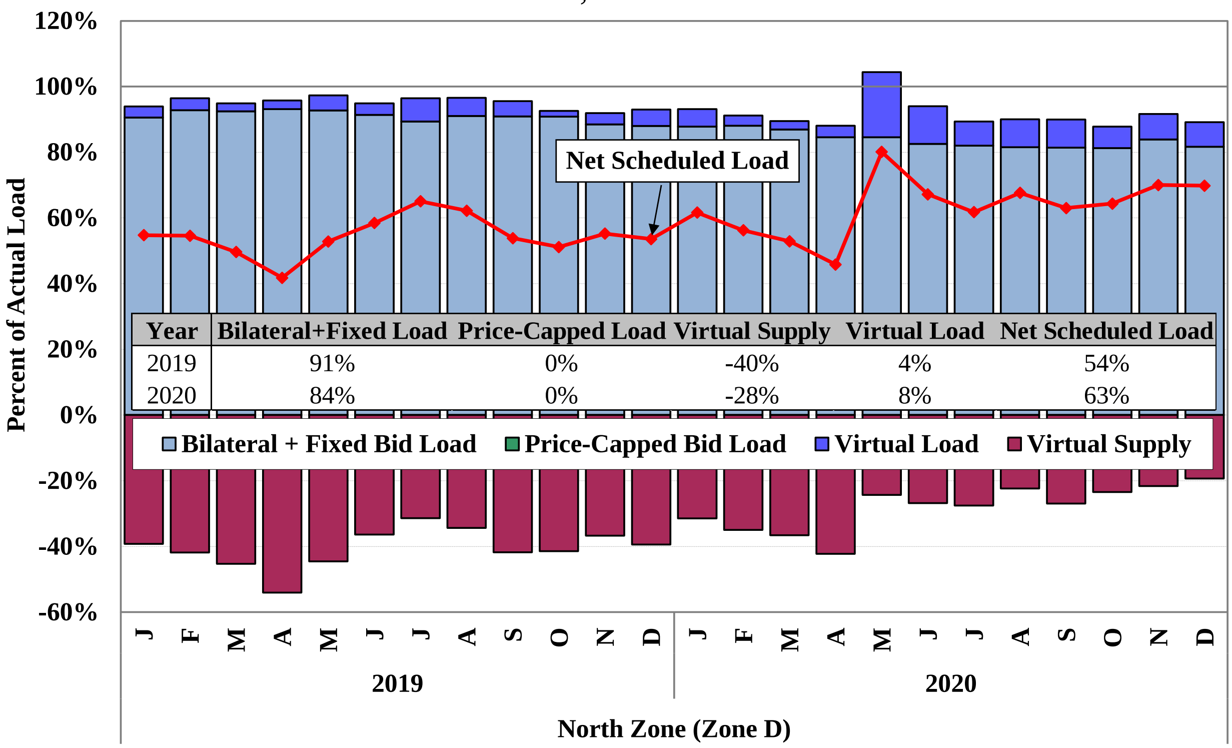
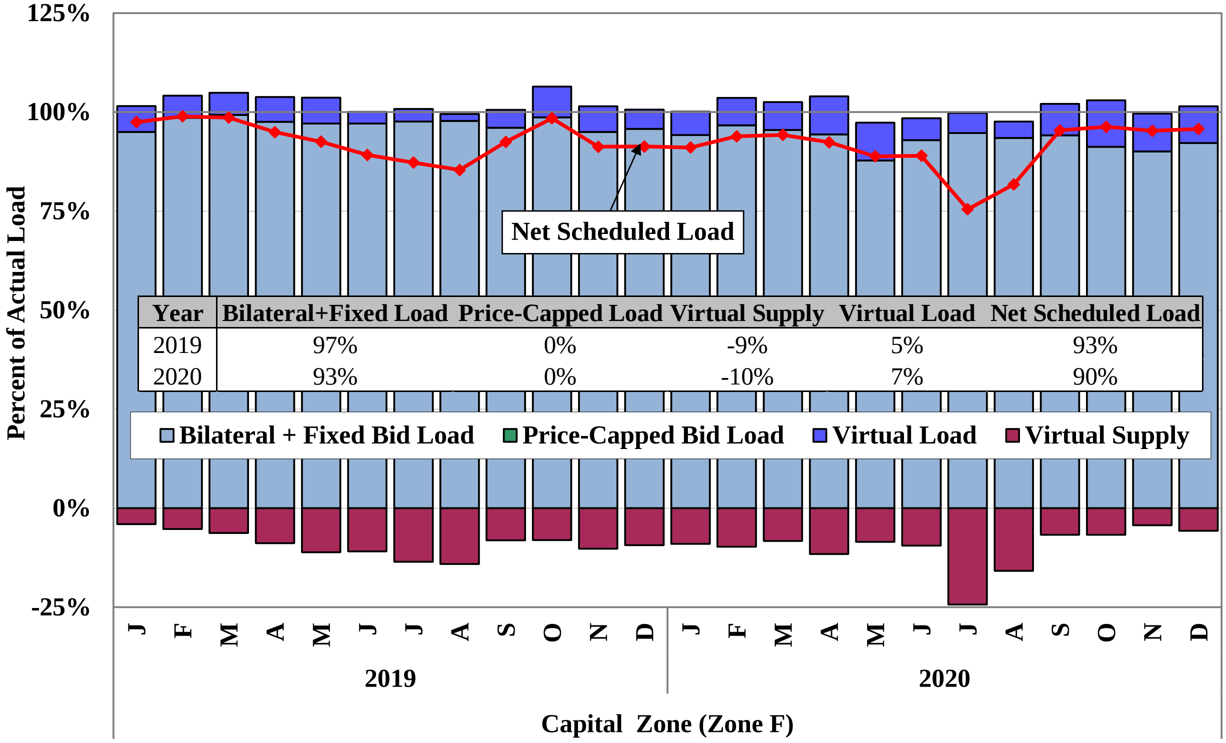


Figure A-44: Day-Ahead Load Schedules versus Actual Load in Capital Zone

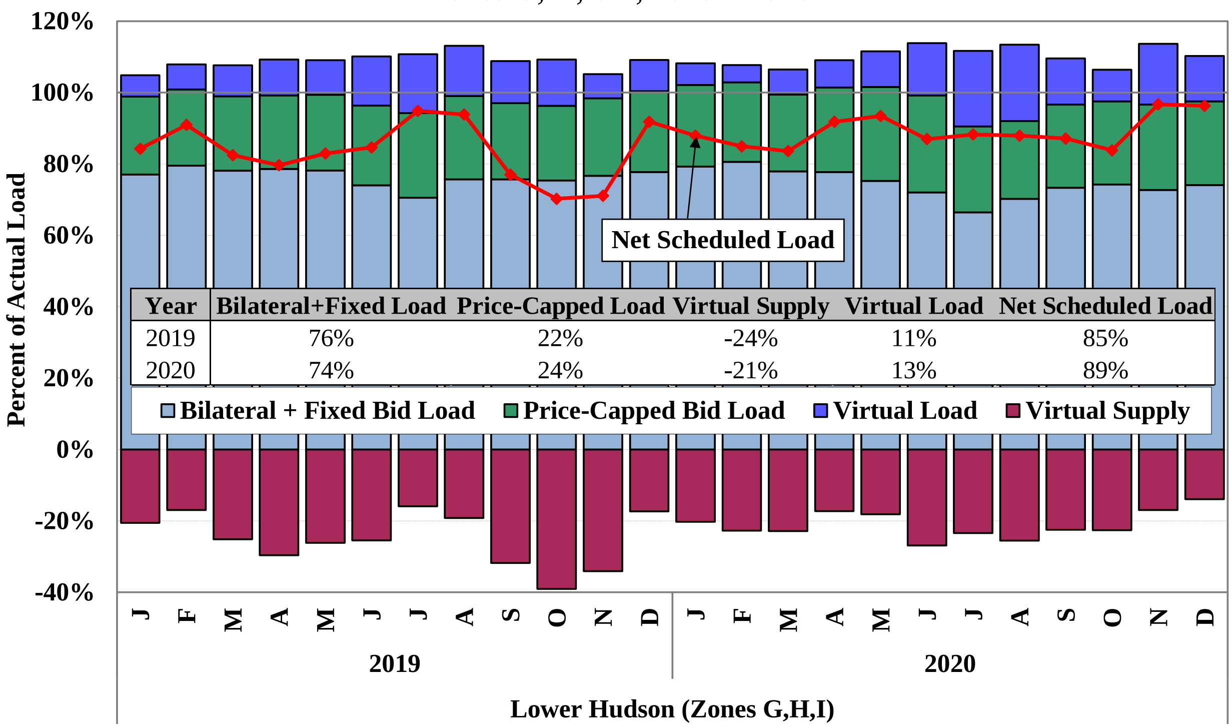
Zone F, 2019 – 2020



Year	Bilateral+Fixed Load	Price-Capped Load	Virtual Supply	Virtual Load	Net Scheduled Load
2019	97%	0%	-9%	5%	93%
2020	93%	0%	-10%	7%	90%

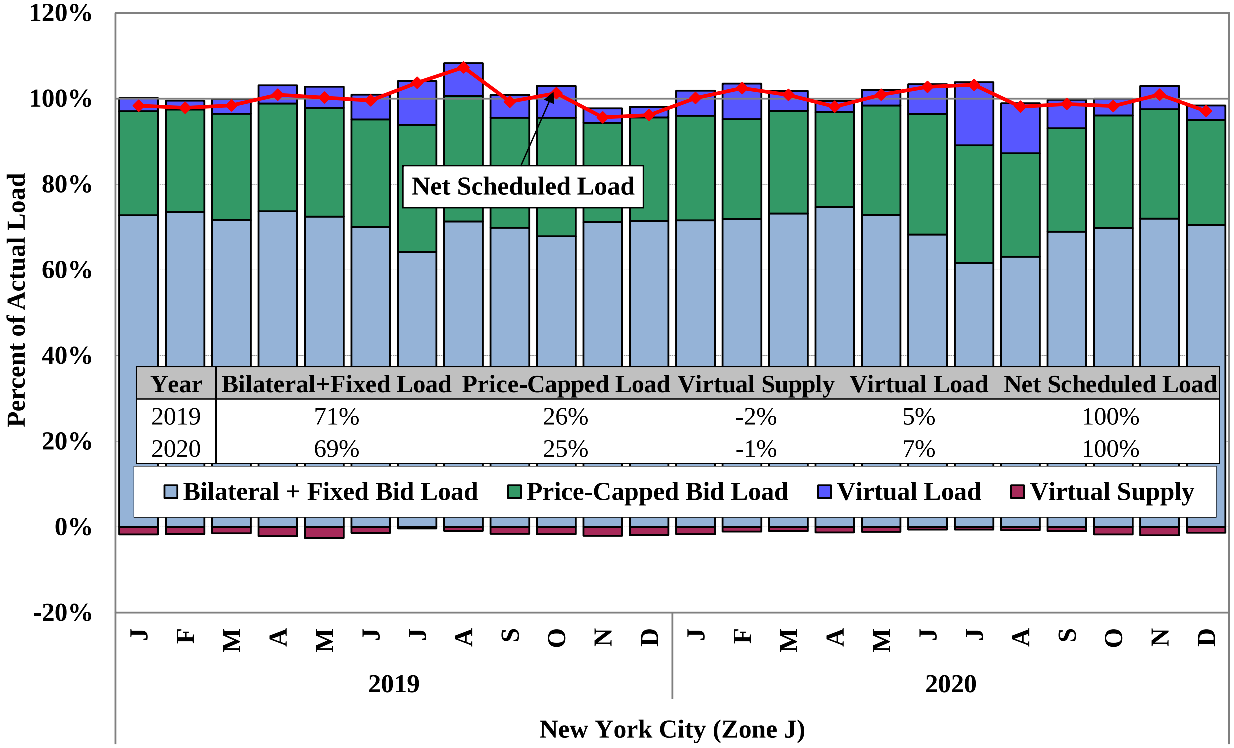
Figure A-45: Day-Ahead Load Schedules versus Actual Load in the Lower Hudson Valley

Zones G, H, & I, 2019 – 2020



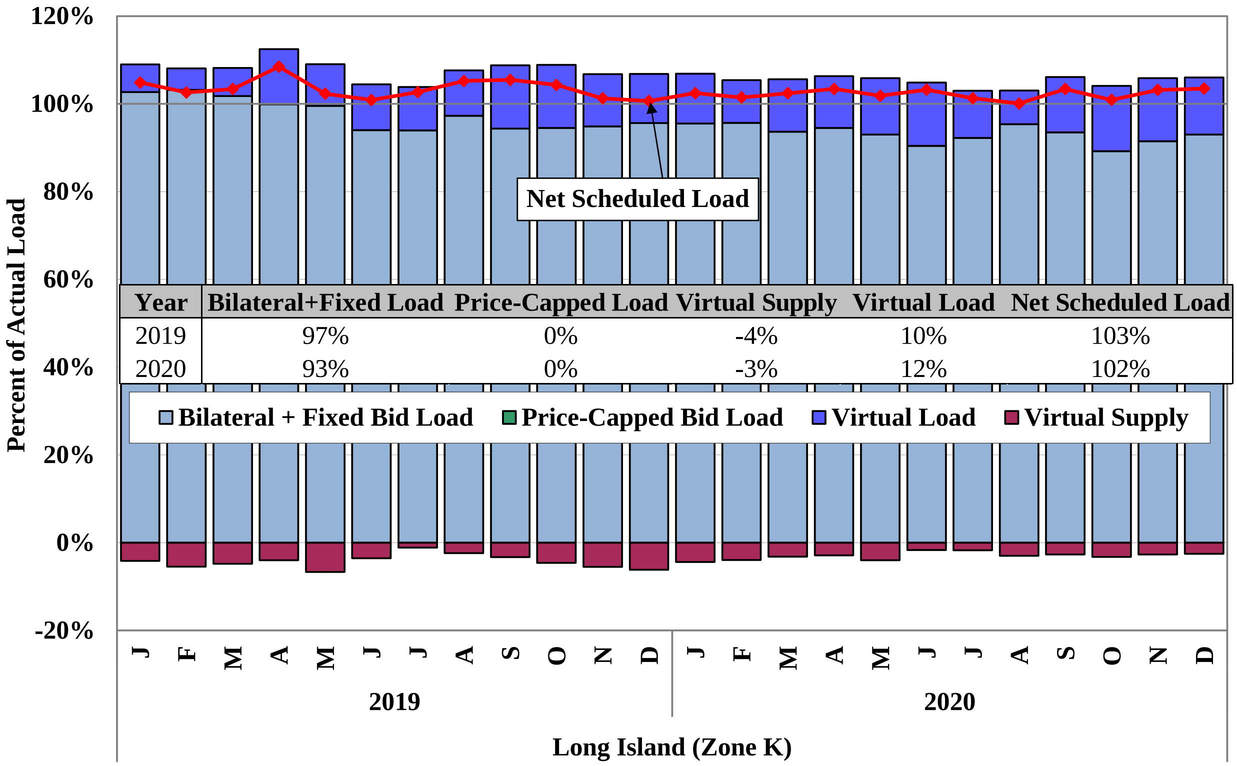
Year	Bilateral+Fixed Load	Price-Capped Load	Virtual Supply	Virtual Load	Net Scheduled Load
2019	76%	22%	-24%	11%	85%
2020	74%	24%	-21%	13%	89%

Figure A-46: Day-Ahead Load Schedules versus Actual Load in New York City
Zone J, 2019 – 2020



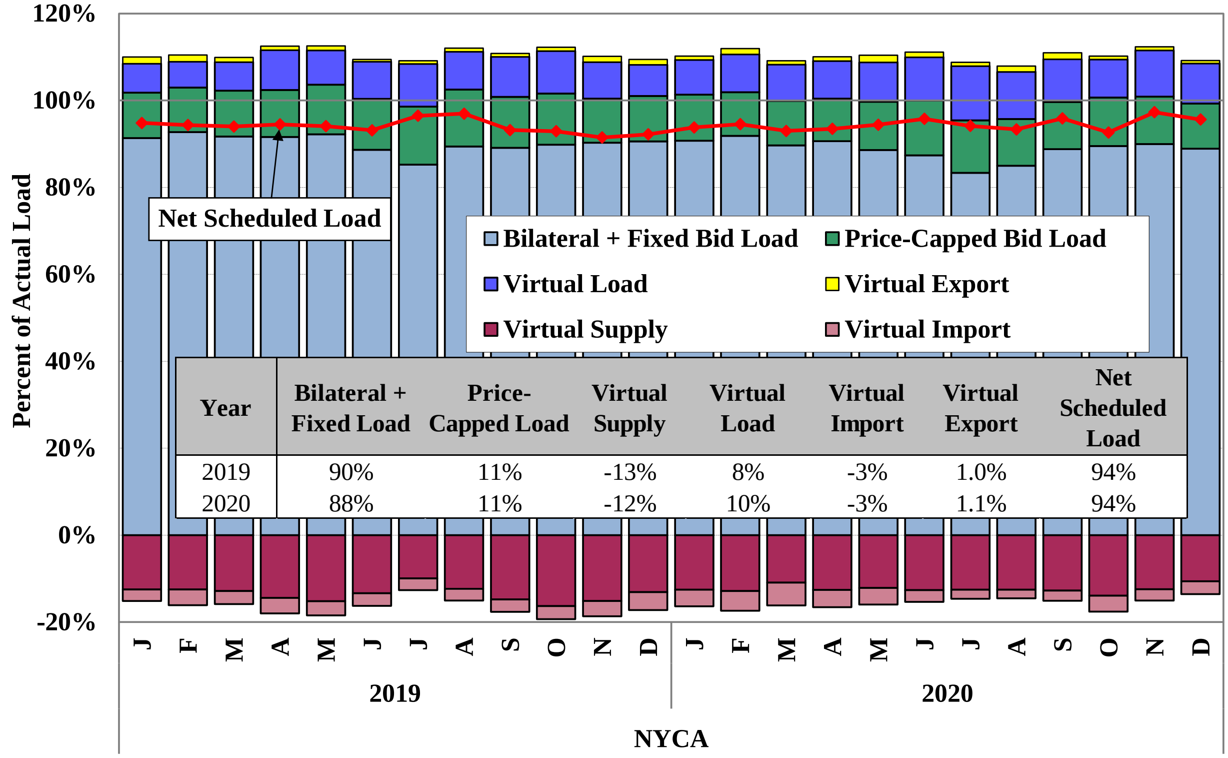
Year	Bilateral+Fixed Load	Price-Capped Load	Virtual Supply	Virtual Load	Net Scheduled Load
2019	71%	26%	-2%	5%	100%
2020	69%	25%	-1%	7%	100%

Figure A-47: Day-Ahead Load Schedules versus Actual Load in Long Island
Zone K, 2019 – 2020



Year	Bilateral+Fixed Load	Price-Capped Load	Virtual Supply	Virtual Load	Net Scheduled Load
2019	97%	0%	-4%	10%	103%
2020	93%	0%	-3%	12%	102%

Figure A-48: Day-Ahead Load Schedules versus Actual Load in NYCA
2019 – 2020



Year	Bilateral + Fixed Load	Price-Capped Load	Virtual Supply	Virtual Load	Virtual Import	Virtual Export	Net Scheduled Load
2019	90%	11%	-13%	8%	-3%	1.0%	94%
2020	88%	11%	-12%	10%	-3%	1.1%	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 2020, similar to 2019 levels.
- While the 2020 scheduling patterns were consistent with the 2019 patterns in many zones, they varied considerably in several others:
  - Overscheduling in the West Zone fell from 2019 levels by 3 percent as congestion in the West Zone fell from prior year levels. The amount of virtual supply scheduled in this region nearly doubled from 2019 levels as day-ahead congestion frequency remained higher than real-time while the values of both markets converged in this region.
  - Virtual supply in the North Zone dropped by 12 percentage points from 2019 levels. In particular, virtual supply decreased and virtual load increased from May 2020 onwards, when outages related to Moses Adirondack Smart Path project resulted in reduced transfer capability out of the North Zone.[280] Despite the outages, real-time prices in this zone were higher on average than day-ahead prices, which made it more profitable to reduce virtual supply.

280 See I.G of the Appendix for discussion of outages effects on day-ahead and real-time price convergence.

    – Virtual load jumped to 20 percent of zonal load during May 2020. In general, we investigate unusual scheduling patterns for potential misconduct.

- 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. For example, 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.

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.

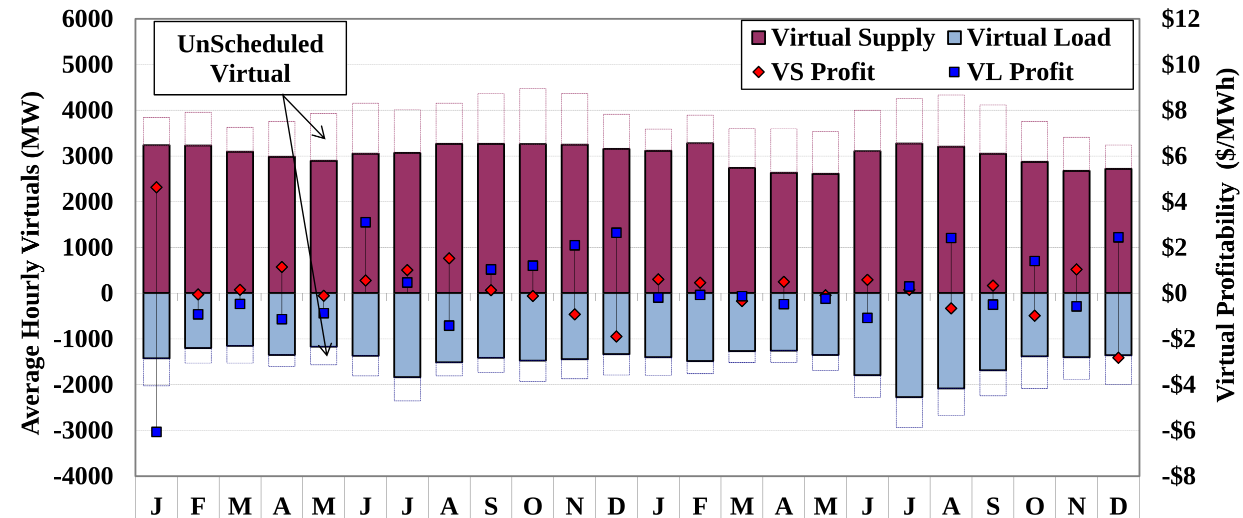
Figure A-49: Virtual Trading Volumes and Profitability

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 2019 and 2020. 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.[281,282]

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 375 MW of virtual transactions (or 9 percent of all virtual transactions) netted profits larger than the 50 percent of their zone (or proxy bus) prices in December of 2020. 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.

Figure A-49: Virtual Trading Volumes and Profitability

2019 – 2020



		J	F	M	A	M	J	J	A	S	O	N	D	J	F	M	A	M	J	J	A	S	O	N	D
		2019												2020											
Profit > 50% of Avg. Zone Price	MW	612	279	167	473	477	587	384	396	249	312	290	274	421	322	232	370	388	464	416	377	196	235	619	375
	%	13%	6%	4%	11%	12%	13%	8%	8%	5%	7%	6%	6%	9%	7%	6%	10%	10%	9%	8%	7%	4%	6%	15%	9%
Loss > 50% of Avg. Zone Price	MW	439	331	178	348	591	548	372	321	293	376	344	305	338	253	321	298	404	460	377	304	198	312	528	440
	%	9%	7%	4%	8%	15%	12%	8%	7%	6%	8%	7%	7%	7%	5%	8%	8%	10%	9%	7%	6%	4%	7%	13%	11%

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

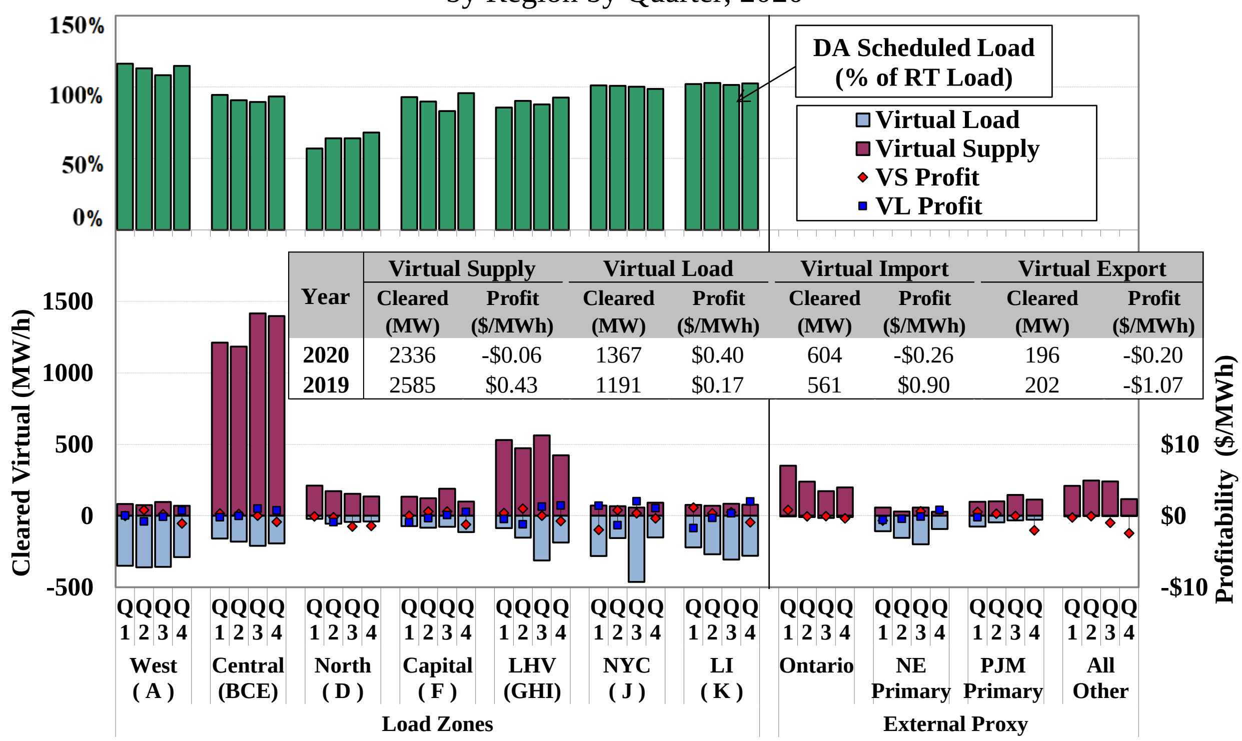
281 The gross profitability shown here does not account for any other related costs or charges to virtual traders.

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

congestion on several interfaces, particularly the Central-East interface. Zone F (the Capital Zone) is shown separately because it is constrained from Western New York by the Central-East Interface and from Southeast New York by constraints in the Hudson Valley. Zones J (New York City) and K (Long Island) are shown separately because congestion frequently leads to price separation between them and other areas. The 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 2020. 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 2019 and 2020.

Figure A-50: Virtual Trading Activity [283]
by Region by Quarter, 2020



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)
2020	2336	-$0.06	1367	$0.40	604	-$0.26	196	-$0.20
2019	2585	$0.43	1191	$0.17	561	$0.90	202	-$1.07

Key Observations: Virtual Trading

- In aggregate, virtual traders netted $2 million of gross profits in 2020 and $14 million in 2019.

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

  - Profitable virtual transactions over the period indicate that they have generally improved convergence between day-ahead and real-time prices.

- Virtual transactions at the borders, i.e., virtual imports and exports, were mostly unprofitable across 2020. However:
  - Some transactions that are scheduled at the external interfaces are curtailed in the real-time market for reliability reasons, either by the NYISO or by the external control area. Many of these transactions are flagged as virtual trades since they are scheduled in the day-ahead but do not occur in real-time despite the intent to flow.
  - Likewise, some transactions categorized here as virtual may not have been scheduled in real-time because of the price differential between regions rather than because the transaction was truly virtual when it was scheduled in the day-ahead market. In such cases, reducing the physical schedule to 0 MW in real-time may enable the trader to mitigated the financial loss from a day-ahead scheduled transaction.

- 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 2020, consistent with prior periods.
  - Many of these trades that incurred a loss occurred during periods of high real-time price volatility that resulted from unexpected events, and did not raise significant manipulation concerns.
    - For example, virtual supply traders experience significant losses during the December 16 operating day due to numerous outages of large generators which drove several localized and systemwide price spikes.

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, B, and C evaluate congestion revenues collected by the NYISO from the day-ahead market and patterns of congestion in the day-ahead and real-time markets.

- Constraints Requiring Frequent Out-of-Market Actions – Subsection D evaluates the management of transmission constraints that are frequently resolved using out-of-market actions, including 115 kV and 69 kV networks in New York.

- Congestion Revenue Shortfalls – Subsections E and F analyze shortfalls in the day-ahead and real-time markets and identify major causes of shortfalls.

- Transmission Line Ratings – Subsection G analyzes the potential congestion benefit of using ambient-temperature adjusted line ratings in the market model.

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

- Transitioning Physical Contracts to Financial Rights – Subsection I 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 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.[284]

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.[285] 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.[286] 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

284 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).

285 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).

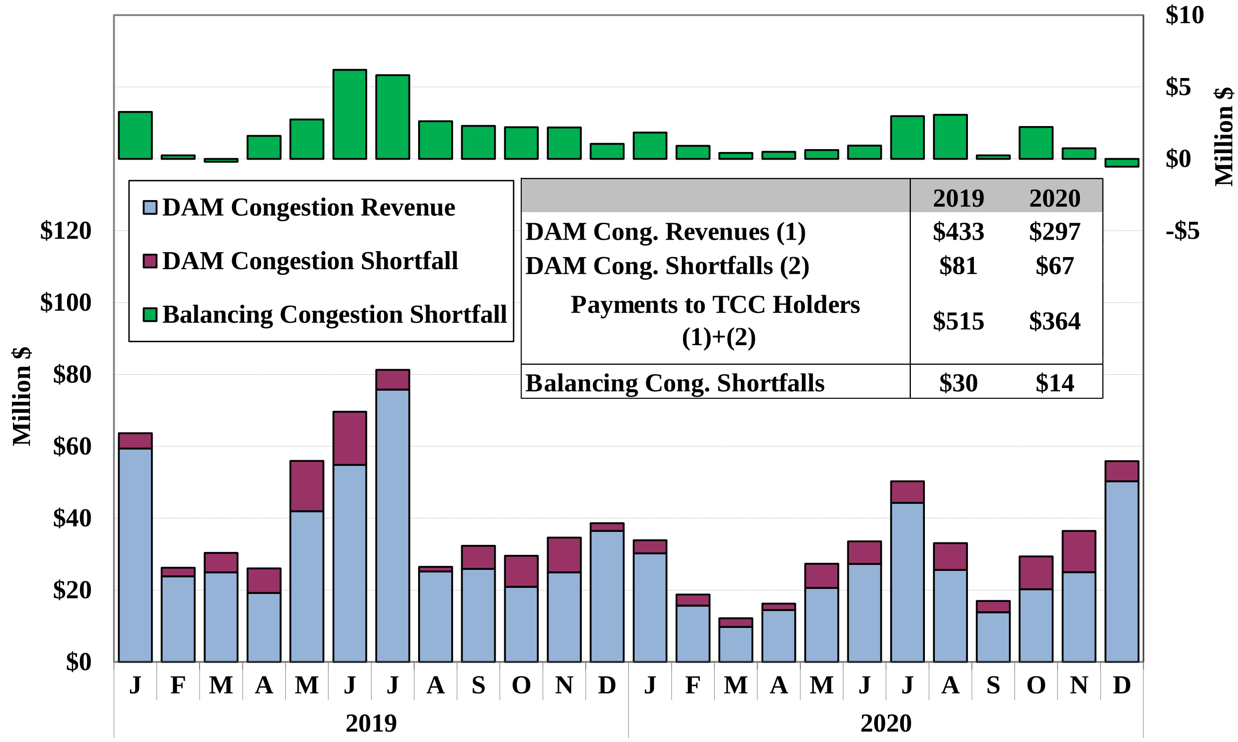
286 For example, suppose 100 MW is scheduled to flow across a particular line in the day-ahead market. If 90 MW flows across the line when it has a shadow price of $70/MWh in an hour in the real-time market, the NYISO will have a balancing congestion shortfall of $700 in that hour ((100 MW – 90 MW) * $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 2019 and 2020. 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
2019 - 2020



B. Congestion on Major Transmission Paths

Transmission lines that move power from the low-cost to high-cost parts of the state provide considerable value. For instance, supply resources in Eastern New York are generally more expensive than those in Western New York, but the majority of the load is located in Eastern New York. 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 2019 and 2020 on an annual basis, while Figure A-53 and Figure A-54 show the quantities separately for each quarter of 2020.

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.[287]

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).

287 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

2019 – 2020

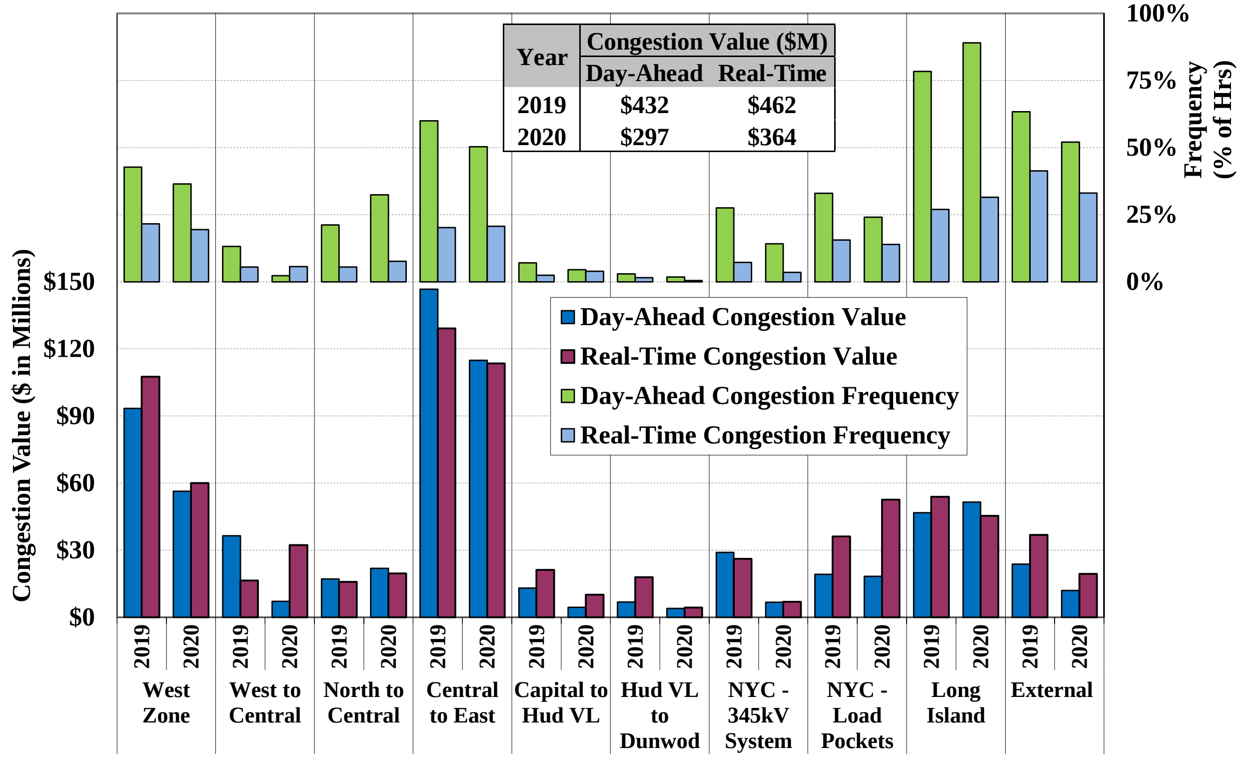


Figure A-53: Day-Ahead Congestion by Transmission Path
By Quarter, 2020

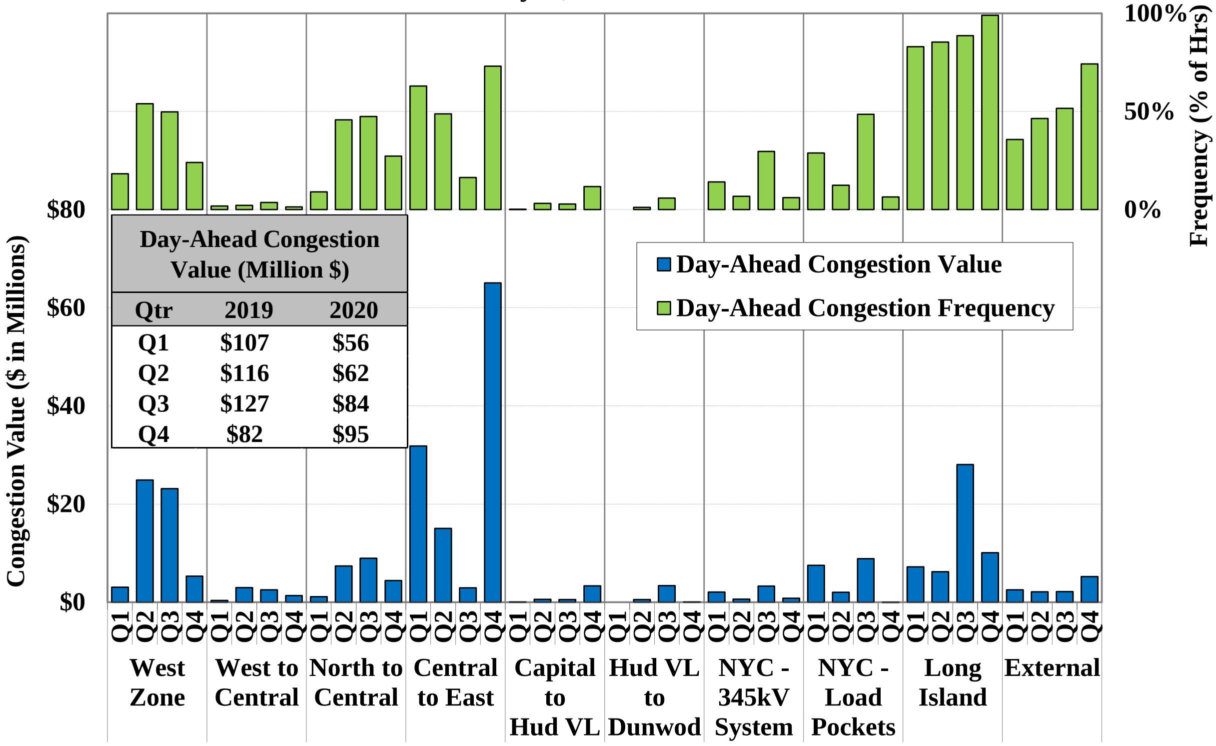
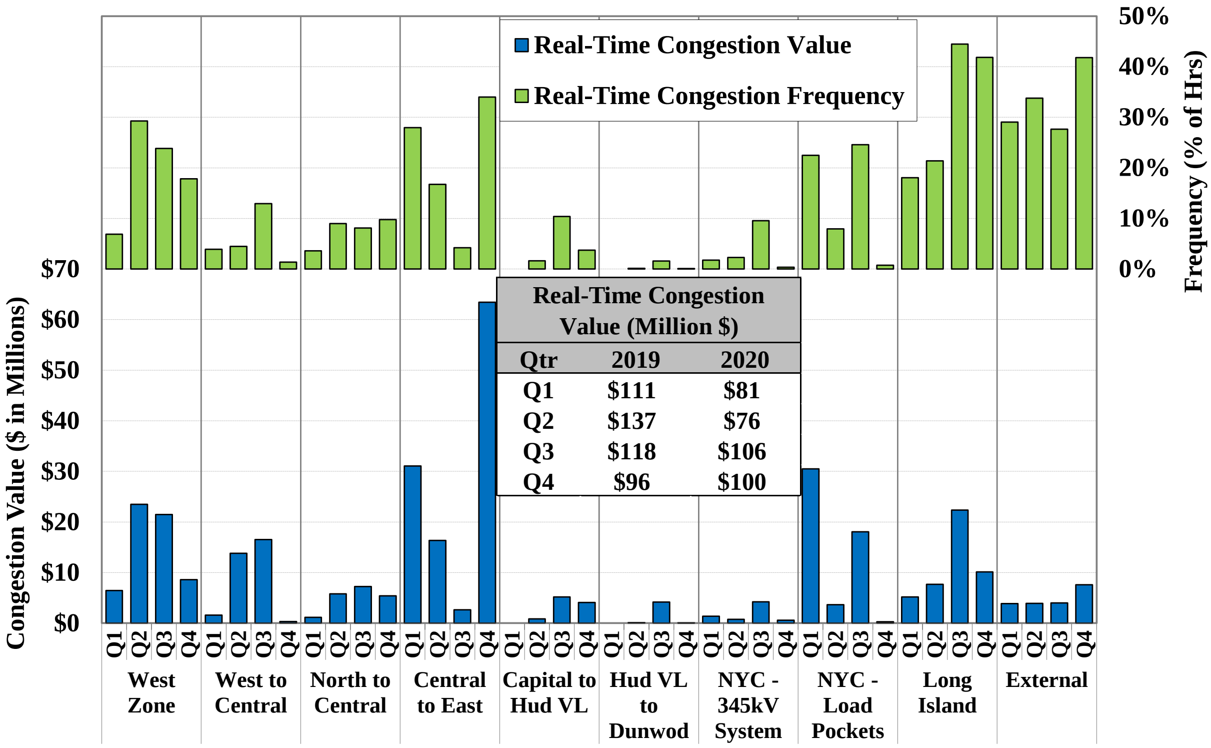


Figure A-54: Real-Time Congestion by Transmission Path
By Quarter, 2020



Key Observations: Congestion Revenues and Patterns

- Day-ahead congestion revenues totaled roughly $297 million in 2020, down 31 percent or $136 million from 2019.
  - This was the first year since the inception of the NYISO market where the annual total congestion revenues in the day-ahead market were below $300 million (not taking into account inflation).
  - The historical low level of congestion in 2020 was primarily driven by low natural gas prices, low gas price spreads across New York, and low load levels resulting from the COVID-19 pandemic.
- Congestion fell in every month from January through September year-over-year by 25 to 61 percent (except for August which was comparable to the previous year). Congestion rebounded in the fourth quarter, however, especially in December when congestion rose by 38 percent.
  - Winter during the first quarter was very mild, and regional gas prices did not diverge to the extent seen in the past several winters. This contributed to much lower congestion on the Central-East Interface.
  - Day-ahead congestion revenues fell $100 million (or 54 percent) from March through July during the height of the pandemic shutdown, despite temperatures being much warmer than average across much of July. Persistently low gas prices and significant load reductions, especially in NYC, drove congestion lower during this stretch.
  - However, the trend reversed in December as colder winter temperatures drove gas prices up in eastern New York and constrained pipelines.
    - Pipelines began issuing OFOs (with tight balancing requirements) in mid-December making gas more difficult to procure, especially after the timely window.
    - Supply changes during 2020 resulted in a net shift of roughly 1 GW of capacity in Eastern New York from nuclear (Indian Point 2) to natural-gas fired resources (Cricket Valley Energy Center). On cold winter days, nuclear capacity is usually available, while gas-fired capacity is more likely to be either unavailable due to pipeline restrictions or very costly due to gas price spikes. This contributed to higher congestion in eastern New York when temperatures fell.
- Despite the reduction, the Central-East interface still accounted for the largest share of congestion values in 2020 (i.e., 39 percent of congestion value in the day-ahead market and 32 percent in the real-time market).
  - The majority of this congestion occurred in the winter months, particularly in December, as a result of higher natural gas prices and larger gas price spreads between regions (which typically increase in the winter season).

- Congestion in the West Zone fell sharply by 40 percent in the day-ahead market and 44 percent in the real-time market from 2019, yet it still accounted for the second largest share of priced congestion in 2020.
  - In addition to low gas prices and low load levels, the following factors also contributed to lower congestion in this area:
    - Clockwise loop flows around Lake Erie fell from 2019 to 2020. (see subsection E)
    - The NYISO and PJM incorporated West Zone 115 kV constraints into the M2M process starting in November 2019.
    - There were fewer costly transmission outages in 2020. (see subsection F)
- Similarly, congestion on the New York City 345 kV network fell 77 percent in the day-ahead market and 74 percent in the real-time market from 2019.
  - However, the load pockets on the 138 kV network saw a small reduction (5 percent) in day-ahead congestion and a large increase (46 percent) in real-time congestion. This disparity was related to periods of high congestion into the Greenwood pocket in January and February because of transmission outages (see subsection F). The capacity in this pocket is made up of peaking units, which are scheduled by RTC, so inaccurate projections by RTC lead to transient real-time shortages in the pocket.
- Nonetheless, North to Central New York and Long Island saw modest increases in congestion from 2019 and 2020.
  - Congestion from North to Central New York increased by more than 20 percent from 2019 to 2020, attributable to transmission outages taken for the Moses-Adirondack Smart Path Reliability Project (see subsection F).
  - Long Island congestion rose 10 percent in the day-ahead market, which occurred primarily in the second half of the year. Contributing factors include:
    - Higher load levels in the summer because of increased residential load during the pandemic and warmer summer temperatures.
    - Lengthy transmission outages on the Cross Sound interface, the Neptune interface, and the Y49 circuits into Long Island. (see subsection F).

C. Real-Time Congestion Map by Generator Location

Figure A-55 to Figure A-56: Real-Time Load-Weighted Congestion Maps by Location

The charts in subsection B report congestion patterns aggregated either on a zonal basis or along specific large interfaces, in this subsection, we display more granular information pertaining to congestion across generator nodes. Figure A-55 and Figure A-56 are two congestion maps showing such information for the entire system and New York City, respectively.

These maps display differences in LBMPs between generator nodes across the system, illustrating transmission bottlenecks not only between broader areas but also within smaller subareas, highlighting the prevalence of intra-zonal price divergence between generation pockets and load pockets. Often, significant congestion arises from an abundance of inexpensive generation located in an export pocket driving bottlenecks on transmission lines servicing load pockets with a small number of competing generators. It also highlights where generation or transmission investment is likely to be most valuable, which can help guide investment.

Each map shows several details highlighting nodal congestion trends in the real-time market in 2020, specifically:

- The load-weighted hourly average real-time LBMP at each generator node within the respective footprint;
- For the systemwide map, real-time prices on the neighboring area's side of the external interface are aggregated and load-weighted using the New York systemwide load and presented as additional bubbles. These bubbles are not sized based on generation totals;[288] and
- Pertinent gas market information including regional gas prices in the systemwide map and key operational points of gas delivery in the NYC map.[289]

The generator nodes prices are displayed at bubbles that are sized based on annual total generation. The sizing of these bubbles differs between each map due to the disparities in geographical sizes of the entire system versus New York City. In each case, however, a floor value is set such that generators at or below a certain annual output total all appear with the same size (i.e., the smallest sized bubble on the map), while generators with greater annual output totals are shown with a size that increases with their total annual generation. Portfolios with multiple generator PTIDs at the same station or within close proximity to each other are aggregated into one bubble and sized based on total portfolio generation.

Finally, each generator bubble is colored based on a heat mapping scale included to the right of each map. Prices along the color-scale are included with colder colors representing lower load-weighted real-time prices.

288 The external interface prices are sourced from the respective system operator web platforms for each region. These prices can be found for each region at PJM, ISO-NE, and IESO web platforms.

289 Natural gas prices are based on the average index prices without additional adders sourced from Platts.

Figure A-55: NYCA Real-Time Load-Weighted Generator Congestion Map
2020

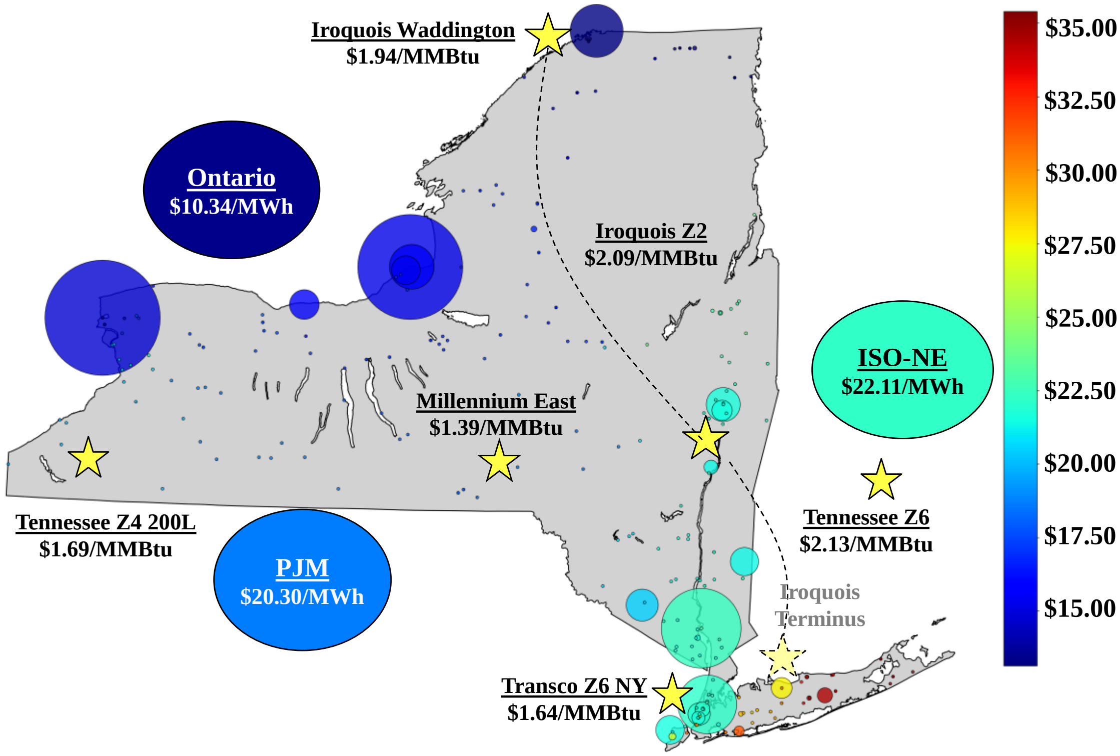
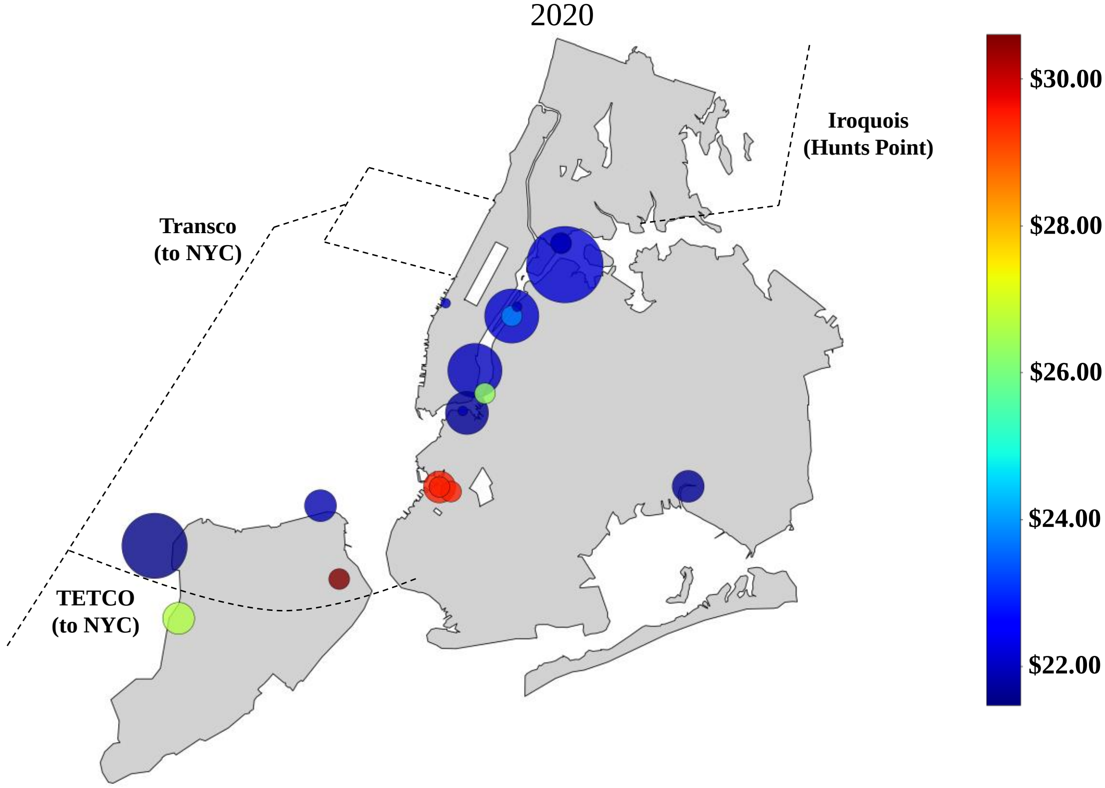


Figure A-56: NYC Real-Time Load-Weighted Generator Congestion Map
2020



Key Observations: Real-Time Congestion Map by Generator Location

- Generator prices across the state ranged from about $13 per MWh to $35 per MWh in 2020, with prices generally increasing from West to East and from North to South.
    - This moving trend in energy prices coincided with the differences between regional gas prices across the state.
- Long Island generators exhibited the highest prices among all areas, ranging roughly from $27 per MWh to $35 per MWh.
    - The lowest prices on Long Island were confined to the western part where gas deliveries are more available and a significant portion of the baseload generation is situated.
    - However, gas is less available, and in many instances unavailable, to the eastern end of the island. The transmission from west to east is often bottlenecked when transmission outages are present and/or when load rises, leading to generally high prices on the eastern part of the island.
        - In addition, frequent OOM actions were taken to schedule oil-fired resources to manage the 69 kV constraints and TVR needs in Eastern Long Island (see discussions in subsection D). This tends to mask some of the otherwise efficient price patterns that would arise when such constraints were modeled in the market systems.
- The West Zone showed a stark contrast in prices between generation frequently bottled near the Niagara facility and higher-cost resources downstream of those constraints.
    - The non-hydro generation in this region tends to be very inflexible, operating at fixed points rather than within a dispatchable range. Frequently, the amount of relief these resources could economically provide to bottlenecks around Niagara is less than the minimum operating levels offered by the units. Thus, the model frequently does not commit units at certain locations that exhibit relatively high price levels.
- Prices within New York City ranged between $22 and $30 per MWh in 2020, showing some localized congestion patterns.
    - Much of the output in the city was produced by several large generating stations in the 345 kV system. Accordingly, congestion often arose into load pockets on the 138 kV network.
    - The Greenwood load pocket typically saw the highest congestion level in New York City as most of the resources inside the pocket are inflexible expensive GTs.
    - The Staten Island pocket is different. It becomes an export-constrained area when high imports from VFT and high generation from Arthur Kill STs are scheduled, making it a lower-priced region relative to the Greenwood pocket; while it is typically

not export-constrained when none or only a small amount of generation is scheduled from Arthur Kill STs, leading to no price separation from the Greenwood pocket.

- Overall, transparent nodal prices provide signals for potential investments by highlighting areas where congestion relief from new generation would be most valuable.

D. Transmission Constraints on the Low Voltage Network Managed with OOM Actions

Transmission constraints on the high-voltage network (including 230 and 345 kV facilities in upstate New York and most 138 kV facilities in New York City and Long Island) are generally managed through the day-ahead and real-time market systems. 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 low-voltage (i.e., 115 kV and lower) network were usually managed with out-of-market operator actions until recent years when the NYISO started to incorporate these low-voltage constraints into the market systems. The typical operator actions to resolve constraints on the low-voltage network include: (a) out of merit dispatch and supplemental commitment of generation; (b) curtailment of external transactions and limitations on external interface transfer limits; (c) use of an internal interface/constraint transfer limit that functions as a proxy for the limiting transmission facility; and (d) adjusting PAR-controlled line flows on the high voltage network.[290] In this subsection, we evaluate:

- The frequency of such OOM actions used to manage transmission constraints on the low voltage network in New York (including 115 kV and 69 kV facilities) that are not incorporated in the market systems;
- The potential pricing impact in several load pockets on Long Island; and
- The efficiency of using high-cost oil-fired generation to manage low voltage constraints in the East of Northport load pocket on Long Island.

Figure A-57 & Figure A-58: OOM-Managed Transmission Constraints on the Low Voltage Network

Figure A-57 shows the number of days in 2020 when various resources were used out of merit to manage constraints in six areas of New York: (a) West Zone; (b) Central & Genesee Zones; (c) Capital Zone; (d) North & Mohawk Valley Zones; (e) Hudson Valley Zone; and (f) Long Island.

290 These constraints are sometimes managed with the use of line switching on the distribution system, but this is not included in our analysis here.

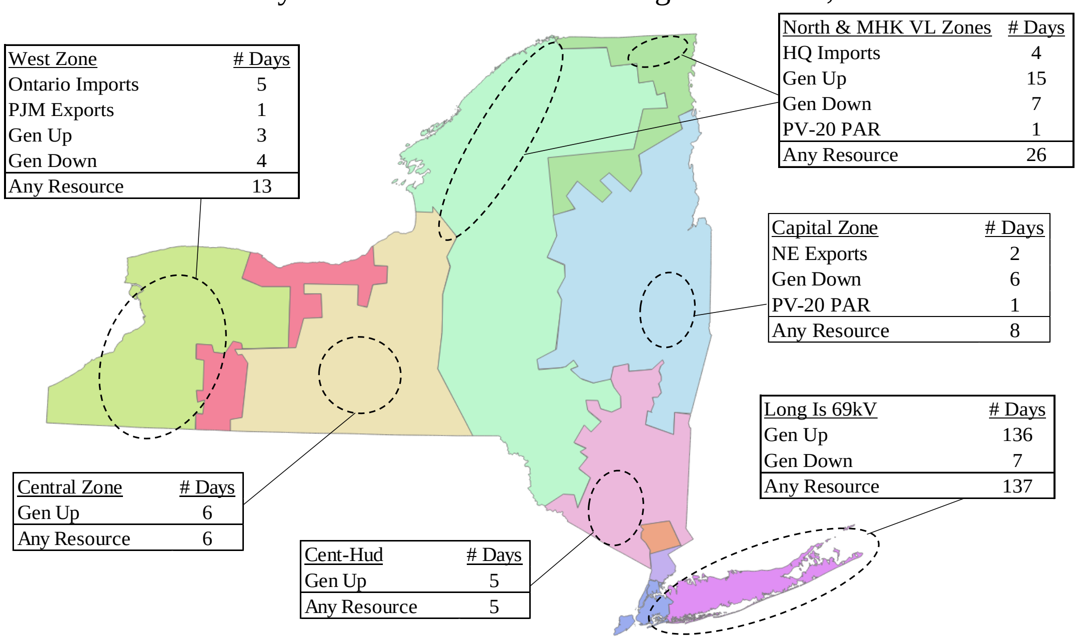
Figure A-58 focuses on the area of Long Island, showing the number of hours and days in 2020 when various resources were used to manage 69 kV and TVR ("Transient Voltage Recovery") constraints in four load pockets of Long Island:

- 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-58 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.[291]

Figure A-57: Constraints on the Low Voltage Network in New York

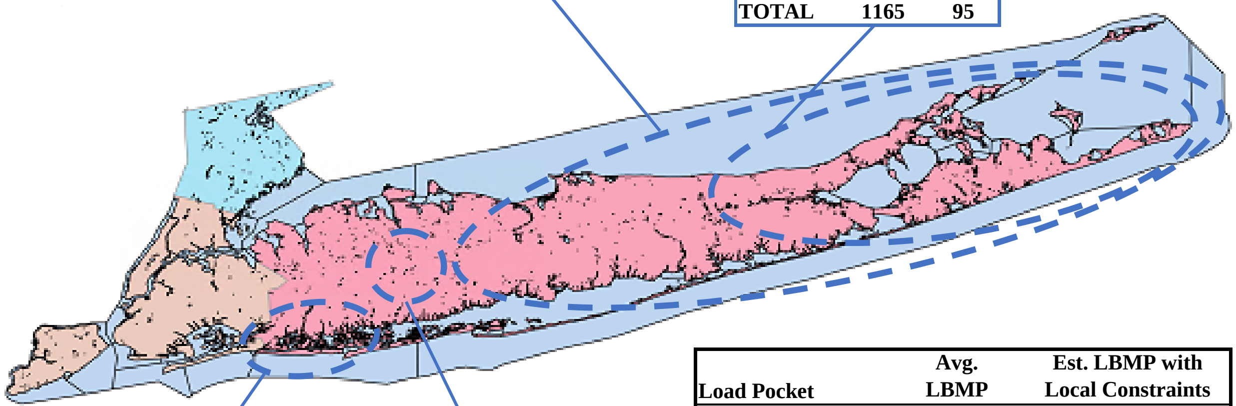
Summary of Resources Used to Manage Constraint, 2020



291 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-58: Constraints on the Low Voltage Network on Long Island

Frequency of Action Used to Manage Constraint, 2020



East of Northport	#Hours	#Days
69kV	480	51
138kV	1336	124
TOTAL	1529	132

East End	#Hours	#Days
69kV	114	13
138kV	2	1
TVR	1115	90
TOTAL	1165	95

Brentwood	#Hours	#Days
69kV	312	54
138kV	0	0
TOTAL	312	54

Valley Stream	#Hours	#Days
69kV	1050	79
138kV	4513	284
TOTAL	5040	291

Load Pocket	Avg. LBMP	Est. LBMP with Local Constraints
Brentwood	$27.97	$28.54
East End	$31.45	$48.13
East of Northport	$30.68	$35.62
Valley Stream	$29.15	$33.70

Figure A-59: Oil-fired Generation in East of Northport Load Pocket on Long Island

Figure A-59 evaluates the efficiency of using oil-fired generation to manage constraints in the East of Northport load pocket on Long Island in the real-time market in each month of 2020. The bottom portion of the chart summarizes the following quantities from resources in East of Northport pocket during hours when oil-fired generation was used to manage 69 kV (by OOM) or 138 kV (by market model) constraints in this area:

- *Oil-fired generation* - The oil-fired generation scheduled to manage congestion on the 69 kV network by OOM or on the 138 kV network by the market model broken out by these characterizations.

- *Low-cost generation & imports* – All other generation scheduled from resources that are not in the "Oil-fired generation" category, including scheduled CSC imports and oil production that was either self-scheduled, audited, or OOMed for TVR support on the East End of Long Island.

- *Low-cost unscheduled generation & imports* - Unscheduled generation in the pocket from low cost resources, which includes the unscheduled portions of baseload combined cycles in the load pocket, unscheduled imports on the CSC (excluding outages and oil-equivalent bids), unscheduled portions of Port Jeff ST units (when online in real-time and considering fuel restrictions), and unscheduled gas GT generation (also considering fuel restrictions).

These quantities are limited to summarizing hours where at least 5 MWh of "oil-fired generation" was scheduled for 69 kV or 138 kV constraints.

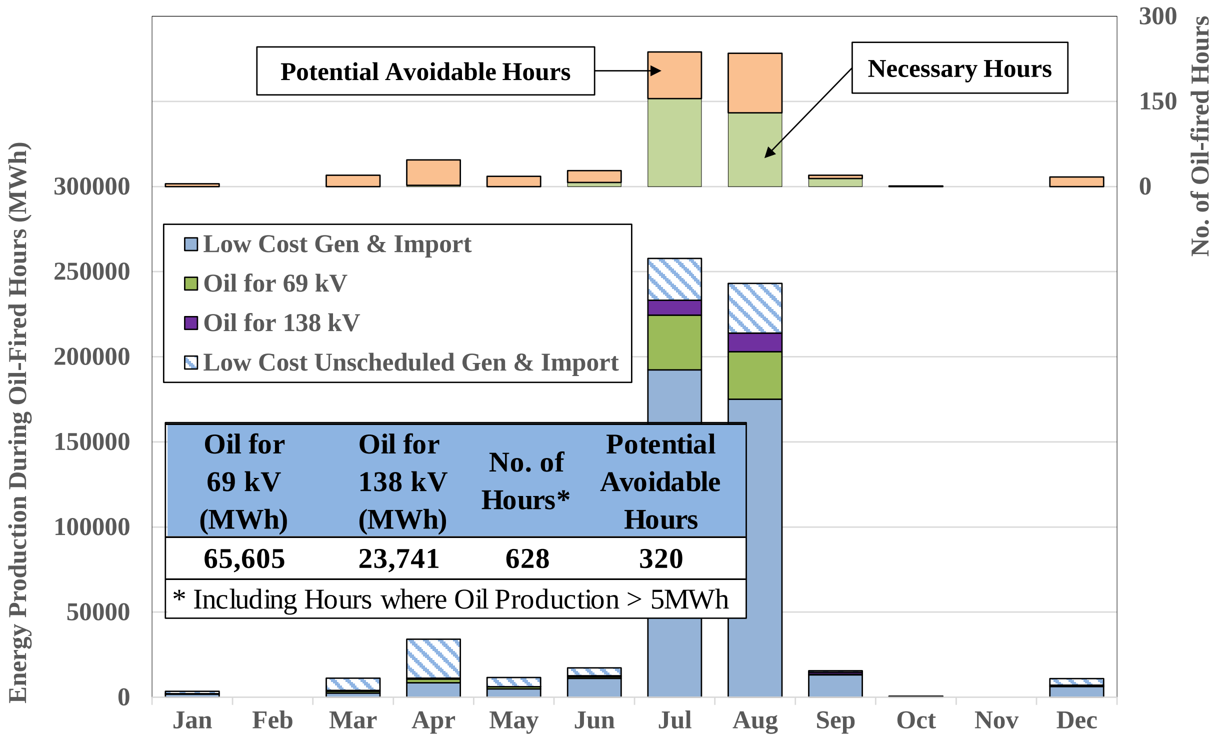
The upper portion of the chart provides our assessment of the efficiency (or necessity) of using high-cost oil-fired generation for congestion management on the 69 kV or 138 kV constraints in this load pocket by showing the following two quantities:

- *Oil hours – necessary*: The number of hours per month where the amount of "oil-fired generation" was greater than the amount of "low-cost unscheduled generation & imports".
- *Oil hours – unnecessary*: The number of hours per month where the amount of "low-cost unscheduled generation & imports" was greater than the amount of "oil-fired generation".

The "Oil hours – unnecessary" bars identify potential hours where such oil-fired generation was potentially avoidable if 69 kV constraints were managed efficiently.

The inset table provides details on oil-fired generation (as defined above) for the year and the number of hours where unscheduled low-cost generation & imports was greater than the amount of oil-fired generation.

Figure A-59: Oil-fired Generation in East of Northport Load Pocket
By Month, 2020



Key Observations: Transmission Constraints on the Low Voltage Network Managed Using OOM Actions

- The NYISO has greatly reduced the use of OOM actions since 2018 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 13 days in 2020, down from 50 in 2019, and 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.
  - The NYISO has a process to routinely assess the need and feasibility of securing 115 kV constraints that require OOM actions in the day-ahead and real-time market models.
    - Despite the great reduction in recent two years, OOM actions were still used to manage certain 115kV constraints that the NYISO has difficulty modeling accurately in the market systems and the 69 kV constraints in some upstate regions and Long Island.
- OOM actions to manage lower-voltage network congestion were most frequent on Long Island in 2020, occurring on 137 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-58) 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).

        - The NYISO made an improvement in mid-July, 2020, to forecast Pilgrim PAR flows more accurately in the day-ahead market, which helps commit generation more efficiently inside the pocket.

    - Oil-fired generation was used to manage 69 kV and 138 kV constraints in the East of Northport Load Pocket on Long Island on 91 days in a total of 628 hours in 2020.
        - Total output of this type was 89.3 GWh, of which 73 percent was related to manage congestion on the 69 kV constraints. And 91 percent of the 69 kV OOM output occurred in July and August during high load days alongside with the outage of the Cross Sound Cable.
        - During 51 percent of these hours (320 hours), the amount of unscheduled low-cost generation (i.e., unscheduled gas-fired capacity and/or CSC imports) exceeded the amount of oil-fired generation, implying that the oil-fired generation would likely have been avoidable during these hours had the 69 kV constraints secured in the market software.
    - We recommend that the NYISO model the 69 kV constraints and East End TVR needs (using surrogate thermal constraints) in the market software.
        - This would greatly reduce associated BPCG uplift (roughly $14 million in 2020, see Figure A-103), better compensate resources that satisfy the needs, and provide more efficient signals for future investment.
        - Our estimates show that: (a) average LBMPs would have risen by as little as $0.57/MWh in the Brentwood load pocket and $4.94/MWh in the East of Northport pocket to $16.65/MWh in the East End load pocket in 2020 (see Figure A-58); and (b) net revenues of a new Frame 7 unit on Long Island would rise $35/kW-year. (see Figure A-131)
        - Recently, the NYISO has begun to incorporate the most frequently binding 69 kV constraints on Long Island in the market systems. On March 4, 2021, the NYISO announced its intention to secure two 69 kV facilities in the day-ahead and real-time markets effective April 14 and April 13 of 2021.[292] This is a positive move towards more efficient resource scheduling and pricing on Long Island.

E. Lake Erie Circulation and West Zone Congestion

The pattern of loop flows around Lake Erie has a significant effect on power flows in the surrounding control areas. Loop flows that move in a clockwise direction around Lake Erie generally exacerbate west-to-east transmission constraints in New York, leading to increased congestion costs in New York, while counter-clockwise loop flows alleviate west-to-east congestion in New York.

292 The following two 69 kV constraints are planned for the April 2021 software deployment: the Brentwood-Pilgrim line and the Elwood-Pulaski line.

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 are 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-60: Clockwise Loop Flows and West Zone Congestion

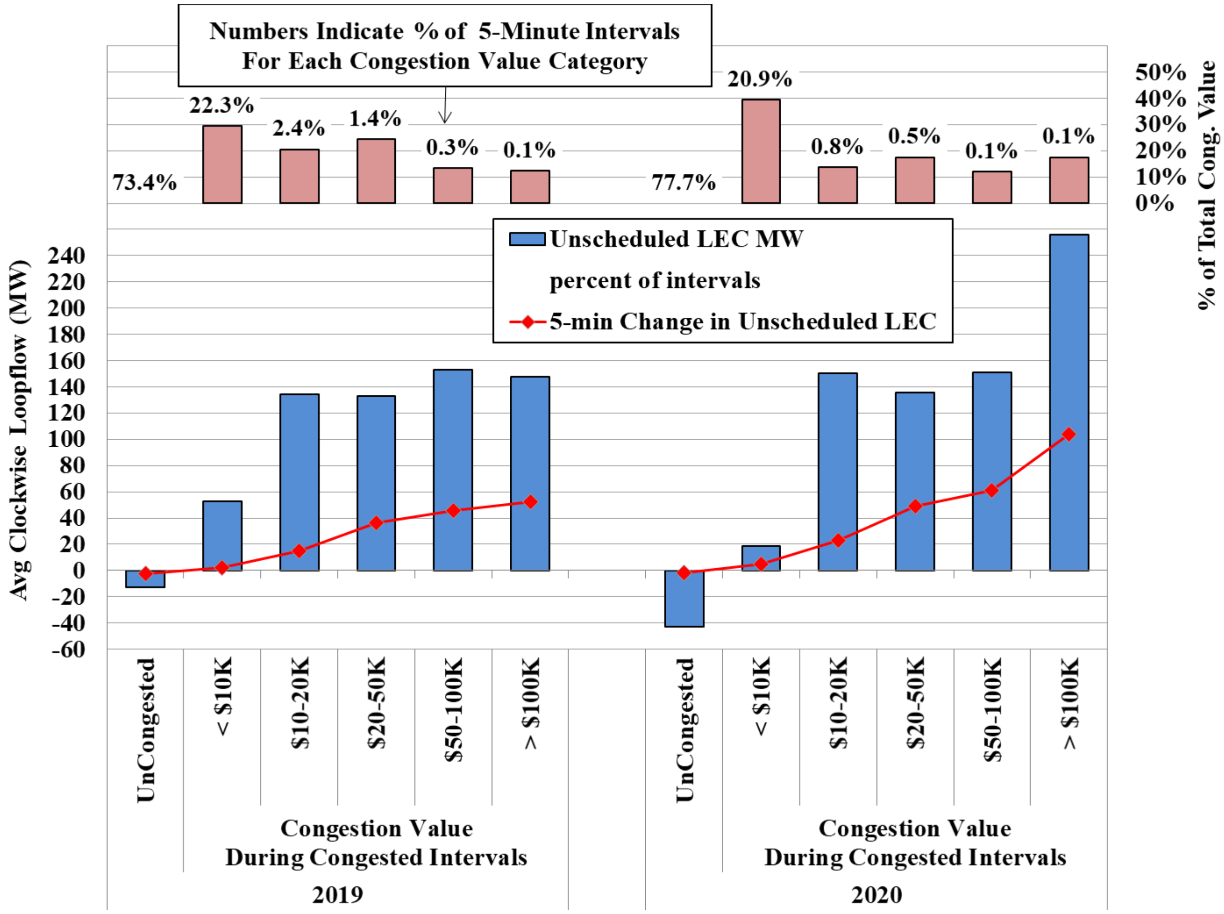
Unscheduled clockwise loop flows are primarily of concern in the congested intervals, when they reduce the capacity available for scheduling internal generation to satisfy internal load and increase congestion on the transmission paths in Western New York, particularly in the West Zone.

Figure A-60 illustrates how and to what extent unscheduled loop flows affected congestion on market-modeled West Zone constraints in 2019 and 2020. 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.[293] 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 2019 and 2020, 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 2020, which however accounted for 18 percent of total priced congestion value in the West Zone.

293 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.

Figure A-60: Clockwise Lake Erie Circulation and West Zone Congestion
2019 – 2020



Key Observations: Lake Erie Circulation and West Zone Congestion

- The average amount of loop flows changed from 8 MW in the *clockwise* direction in 2019 to 27 MW in the *counter-clockwise* direction in 2020, contributing to lower congestion on the West Zone constraints in 2020 (see subsection B for discussion of other contributing factors).
  - Despite the decrease, West Zone congestion was still much more prevalent when loop flows were clockwise or happened to swing rapidly in the clockwise direction.
    - Figure A-60: Clockwise Lake Erie Circulation and West Zone Congestionshows an apparent correlation between the severity of West Zone congestion (measured by congestion value) and the magnitude of loop flows and the occurrence of sudden changes from the prior interval.
    - A small number of intervals with severe congestion accounted for a relatively large share of total priced congestion. Either a large amount of clockwise loop flows or a sudden increase of loop flows in the clockwise direction or both were typically present in these intervals.

   - For example, the congestion values exceeded $100,000 in just 0.1 percent of intervals in both 2019 and 2020, but these intervals accounted for more than 10 percent of total priced congestion values each year. In addition, this share increased from 12 percent in 2019 to 18 percent in 2020, consistent with higher clockwise loop flows and larger swing of loop flows in the clockwise direction during these intervals in 2020.

- 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 uses a higher CRM on some West Zone constraints to accommodate loop flow volatility. For example, the CRM used on the Niagara-Packard 230 kV lines and the Niagara-Robinson Rd 230 kV line is 60 MW, much higher than the 20 MW otherwise used on most of other constraints in the same voltage class.
   - 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; and
   - The NYISO relocated the electrical location of the IESO proxy bus in its scheduling models from the Bruce 500 kV station to the Beck 220 kV station (near the Niagara station in New York) on April 21, 2020. This was intended to have a more accurate representation of the effects of interchange with Ontario.

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

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

Figure A-61: 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 are expected to 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 inconsistent with the assumptions used in the day-ahead market, the congestion revenues collected may be insufficient to meet TCC obligations.

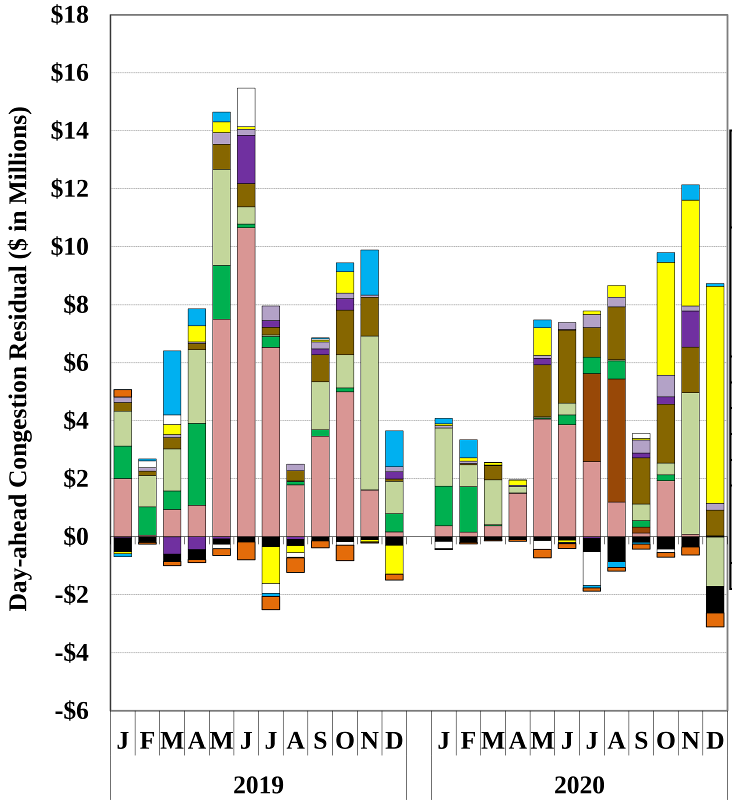
Figure A-61 shows day-ahead congestion shortfalls by transmission path or facility in each month of 2019 and 2020. Positive values indicate shortfalls, while negative values indicate surpluses. The shortfalls are shown for the following paths:

- West Zone Lines: Transmission lines in the West Zone.
- North to Central: Transmission lines in the North Zone, the Moses-South Interface, EDIC-Marcy 345 line, and Marcy 765-Marcy 345 line.
- Central to East: Primarily the Central-East interface.
- Capital to Hudson Valley: Transmission lines into Hudson Valley, primarily lines connecting Leeds, Pleasant Valley, and New Scotland stations.
- New York City Lines: Lines leading into and within New York City.
- Long Island Lines: Lines leading into and within Long Island.
- External: 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-61: Day-Ahead Congestion Shortfalls
2019 – 2020



	Category	Annual Shortfall ($M) 2019	Annual Shortfall ($M) 2020
	Long Island Lines		
	Pilgrim PAR	$0.0	$7.5
	901/903 PARs	-$2.9	-$4.0
	Excess GFTCC Allocations	$2.5	$2.9
	Other Factors	-$0.5	$16.9
	West Zone Lines	$40.8	$16.3
	North to Central	$7.2	$13.8
	Central to East	$19.5	$9.2
	New York City	$9.0	$4.9
	Capital to Hud VL	$1.5	$1.9
	External		
	Primary NY/NE	$6.1	$1.7
	Other	-$2.9	-$2.0
	All Other Facilities	$1.2	-$1.7

Figure A-62: 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.

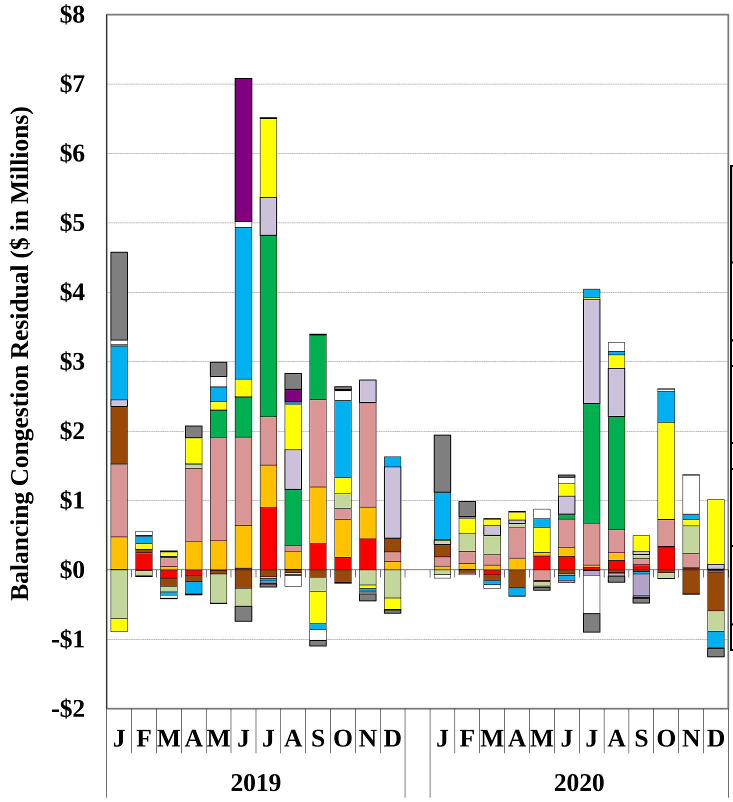
- PAR Controlled Line Flows – The flows across PAR-controlled lines are adjusted in real-time operations, which can result in flows that are very different from the day-ahead assumptions. These differences can affect the flows across multiple interfaces. This includes flow adjustments on PAR-controlled 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-61, Figure A-62 shows balancing congestion shortfalls by transmission path or facility in each month of 2019 and 2020. 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-62: Balancing Congestion Shortfalls[294]
2019 – 2020



Category	Annual Shortfall ($M) 2019	Annual Shortfall ($M) 2020
West Zone Lines		
Ramapo, A & JK PARs	$4.8	$0.7
Other Factors	$8.8	$2.7
North to Central	$2.0	$0.9
Central to East		
Ramapo, A & JK PARs	$0.1	-$1.3
Other Factors	-$2.1	$0.5
TSA Constraints	$5.3	$3.4
Long Island Lines		
Pilgrim PAR	$2.6	$2.8
Other Factors	$2.1	$3.9
New York City	$1.4	$0.5
Hudson Valley to Dunwoodie	$2.3	$0.0
External	$4.2	$1.0
All Other Facilities	$0.1	$0.2

Key Observations: Congestion Shortfalls

Day-Ahead Congestion Shortfalls

- Day-ahead congestion shortfalls totaled $67 million in 2020, down 18 percent from 2019.
  - In 2020, roughly $39 million (or 58 percent) were allocated to responsible Transmission Owners for transmission outages.
- Transmission constraints into and within Long Island accounted for the largest share of congestion shortfalls (roughly $23 million or 35 percent) in 2020.
  - This was a substantial increase from the small amount of surpluses in 2019.
  - The most significant driver was the lengthy outages of the Sprainbrook-East Garden City ('Y49") 345 kV line and its associated PARs and transformers. These facilities were OOS in most of the fourth quarter, leading to nearly $13 million of shortfalls.

294 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.

- Pilgrim PAR accounted for another $7.5 million of shortfalls on Long Island, most of which accrued in July and August.
  - NYISO made an improvement in mid-July, 2021, to forecast Pilgrim PAR flows more accurately in the day-ahead market. This was intended to help commit generation more efficiently inside the East of Northport load pocket to manage congestion on both modeled 138 kV constraints and unmodeled 69 kV constraints.
  - This modeling change shifted part of the cost (in the form of congestion shortfalls) of managing unmodeled 69 kV constraints in the real-time market to the day-ahead market. This shift to the day-ahead market was efficient, since a broader set of resources are generally available in the day-ahead market.
  - The relatively high amount also reflected unusually high congestion into the pocket because of the lengthy outage of the Cross Sound Cable.

- The congestion shortfalls accruing on transmission paths from North to Central nearly doubled to $14 million in 2020.
  - The primary driver was transmission outages related to the Moses-Adirondack Smart Path Reliability Project. At least one of the Moses-Adirondack 230 kV lines (MA1 or MA2) was OOS for two weeks in March and almost the entire period from May to December (with the exception of only a few weeks).

- Shortfalls accrued on the transmission paths in most of other areas fell from 2019, attributable to overall lower congestion levels in 2020 for the reasons discussed in subsection B.
  - The transmission paths in the West Zone saw a large decrease in shortfalls in 2020 to $16 million, nearly a 60 percent reduction from 2019.
    - Most of these shortfalls accrued on 115 kV facilities, which accounted for $14 million of shortfalls in 2020, while the 230 kV facilities accounted for $2 million of shortfalls.
    - Fewer costly transmission outages, which are an important driver of shortfalls, occurred in 2020, contributing to lower shortfalls as well. Less than $4 million of shortfalls were allocated to TOs because of transmission outages.
    - The remaining shortfalls (over $12 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 $9 million of shortfalls in 2020, down 53 percent from 2019.
    - Fewer costly transmission outages also contributed to smaller shortfalls. The most impactful outage in 2020 was the outage of the Massena-Marcy MSU1 765

kV line, which was OOS for three days in early March and eleven days in November. This outage reduced the interface limit by 700 MW, leading to a total of over $6 million of shortfalls in these days.

    - A significant portion of remaining 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. Shortfalls caused by these factors are not allocated to TOs.

  - Fewer costly transmission outages were also a significant driver of lower shortfalls in other regions.
    - For example, New York City only accounted for $5 million of shortfalls in 2020, which was 45 percent lower than in 2019. Most of the shortfalls accrued in January and February with the extended unplanned outages of the Gowanus-Greenwood 138 kV line and in-series Gowanus PAR and transformer.
    - The COVID-19 pandemic affected regular transmission maintenance plans by deferring some projects. As a result, shortfalls resulted from planned maintenances fell notably during the regular maintenance seasons.

- 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.[295]
  - 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 220 MW in that direction in 2019 and 223 MW in 2020.
  - 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 $14 million in 2020, down 53 percent from 2019.
- Balancing congestion shortfalls were generally small on most days of 2020 but rose notably on several days when unexpected real-time events occurred.

295 This is categorized as "901/903 PARs" under "Long Island Lines" in the figure.

  - 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 nearly $3.5 million of shortfalls in 2020, 20 percent of the total shortfalls for the year.
  - Unplanned/forced outages and deratings (including outages and deratings extended beyond the planned period and real-time transfer limit adjustments by operators) were another important driver. Notable examples include:
    - A total of $2.2 million of shortfalls accrued on Long Island because of the trip of the Sprainbrook-East Garden City 345 kV line ("Y49") on October 2 and again on December 4.
    - About $0.6 million of shortfalls accrued on the Ontario interface on January 2 when the interface limit was reduced (i.e., to reduce imports from Ontario) to facilitate congestion management on the Gardenville-Dunkirk 115 kV line ("142 line") in the West Zone.
    - A forced outage of the Gowanus-Greenwood 138 kV line and the Gowanus PAR on January 17 led to $0.4 million of shortfalls in New York City.
- Balancing congestion shortfalls accruing on the West Zone constraints declined to $4 million in 2020, 74 percent below 2019.
  - Although average clockwise loop flows fell in 2020, they continued to be a primary driver of balancing shortfalls in the West Zone .
- The PAR operation under the M2M JOA with PJM resulted in an estimated $0.6 million of surpluses on the Central-East interface and West Zone constraints in 2020.
  - This improved significantly from the $5 million of shortfalls in 2019, the vast majority of which accrued on the West Zone constraints.
  - This was because the NYISO and PJM incorporated West Zone 115 kV constraints into the M2M process starting in November 2019.
- The inconsistency between the assumption of Pilgrim PAR flows in the day-ahead market and its real-time operation contributed nearly $3 million of shortfalls on Long Island in each year of 2019 and 2020.
  - The PAR flows have a significant impact on both the 138 kV and the 69 kV constraints, while only the 138 kV constraints are 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 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.
  - The NYISO incorporated two 69 kV constraints on Long Island into the day-ahead and real-time market models in April 2021.[296]

G. Transmission Line Ratings

Transmission line ratings represent the maximum transfer capability of each transmission line. They are used in the market models to establish commitment and dispatch and affect congestion and prices, therefore it is important to incorporate accurate line ratings. Understated line ratings can lead to inefficient market outcomes (e.g., higher production costs, and unnecessarily high congestion and energy prices), while overstated line ratings may result in potential reliability concerns.

Transmission line ratings are typically based on three types of limits: thermal limits, voltage limits, and stability limits, of which thermal limits are usually the most limiting one for most of transmission lines and interfaces. Thermal limits are typically affected by ambient conditions (e.g., temperature, wind speed, and solar irradiance, etc.). For example, when ambient temperatures are cooler than the typical assumptions used for rating the facilities, additional power flows can be accommodated.

The current NYISO markets use static seasonal line ratings for most facilities in the day-ahead and real-time markets. Although transmission owners provide Ambient Adjusted Ratings ("AAR") to use for some facilities in the real-time market, static line ratings are used for most facilities. FERC issued a NOPR in January 2021, which proposed to require: a) transmission providers to implement AAR on their transmission lines; and b) RTOs/ISOs to establish and implement the systems and procedures necessary to allow transmission owners to electronically update line ratings at least hourly.[297] This subsection examines the potential economic value of using AARs on an hourly basis in the NYISO day-ahead and real-time markets.

Figure A-63: Potential Congestion Benefit of Using Ambient-Temperature Adjusted Ratings

Figure A-63 shows our estimate of potential congestion benefit from using ambient-temperature adjusted line ratings for 2019 and 2020.

We estimate ambient-adjusted ratings based on the following assumptions: [298]

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296 The following two 69 kV constraints are planned for the April 2021 software deployment: Brentwood-Pilgrim and Elwood-Pulaski lines.

297 See FERC Notice of Proposed Rulemaking, Managing Transmission Line Ratings, Docket No. RM20-16-000, January 21, 2021. Also see NYISO comments in response to this NOPR, filed on March 22, 2021.

298 See "Tie-Line Ratings Task Force Final Report on Tie-Line Ratings" by New York Power Pool, 1995.

- Summer line ratings are developed based on an ambient temperature of 95°F (or 35°C);
- Winter line ratings are developed based on an ambient temperature of 50°F (or 10°C); and
- For overhead lines, the relationship between the ambient-adjustment rating factor and the ambient temperature is close to linear in a wide range of normal weather conditions.

Therefore, we extrapolate the ambient adjusted ratings from the straight line that connects the summer and winter ratings and their assumed rating temperatures.[299] Wind speed is a critical parameter that impacts equipment thermal ratings, but its variation is not considered in this calculation.

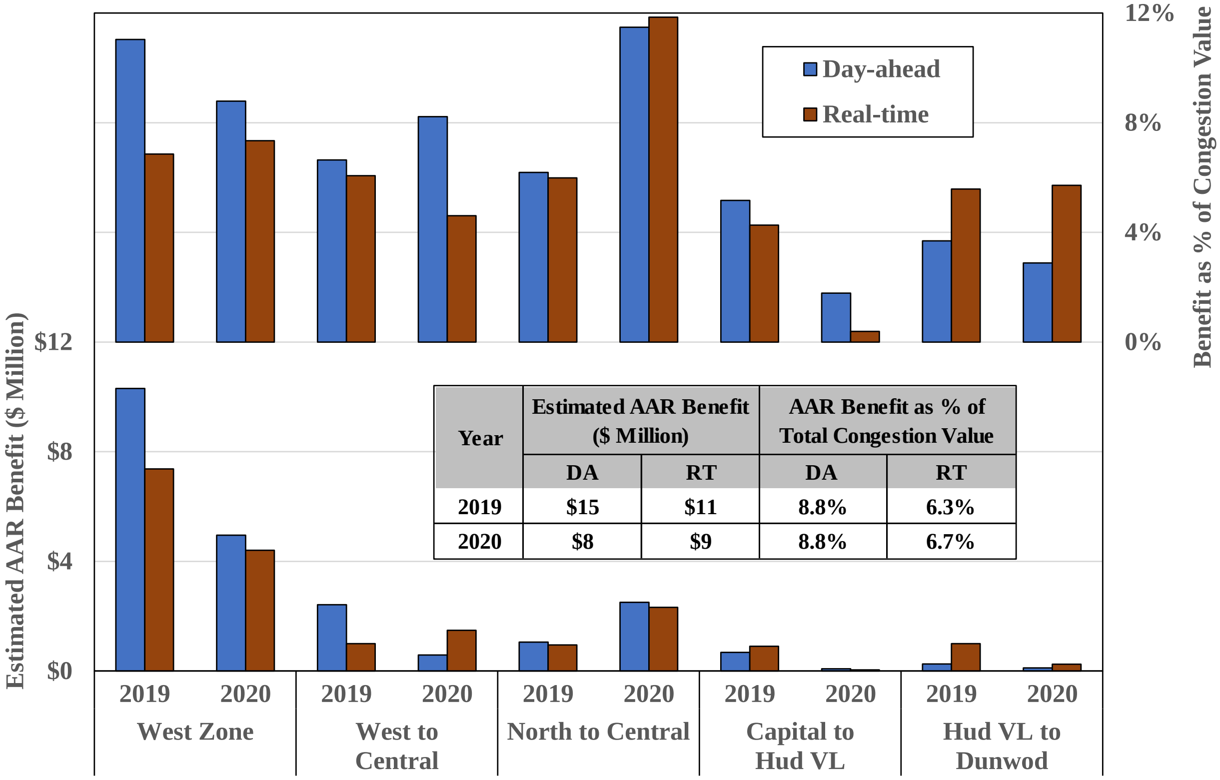
In the figure, the bars in the bottom of the chart represent the estimated potential benefit, which equals the constraint shadow cost times the additional transfer capability from the estimated potential ambient adjustment.[300] These estimates are done separately for the day-ahead and real-time markets on an hourly basis. This is shown separately for facilities: a) in the West Zone; b) from West to Central; c) from North to Central; d) from Capital to Hudson Valley; and e) from Hudson Valley to Dunwoodie. The bars in the top portion of the chart show the potential benefit as a percent of total congestion values in each facility group. The inset table summarizes these quantities on an annual basis for all facilities combined.

The Central-East interface is not included in this analysis because its rating is based on the voltage collapse limit, which is not typically affected by ambient temperature. The transmission facilities in New York City and Long Island are also excluded because most of these facilities are underground cables, whose ratings are not as sensitive to ambient air temperature as overhead lines.

299 For example, if the line rating for a facility is 100 MW in the summer and 145 MW in the winter, then the ambient adjusted rating at 80°F is calculated as 100 + (80-95)*(145-100)/(50-95) = 115 MW.

300 For example, if NYISO uses a rating of 120 MW for one transmission facility in the market model, the facility is binding with a shadow cost of $100/MWh, and our estimated ambient adjusted rating is 150 MW, then the potential congestion benefit is estimated as (150-120)*100 = $3000.

Figure A-63: Potential Congestion Benefit of Using AAR Line Ratings
2019-2020



Year	Estimated AAR Benefit ($ Million)		AAR Benefit as % of Total Congestion Value	
	DA	RT	DA	RT
2019	$15	$11	8.8%	6.3%
2020	$8	$9	8.8%	6.7%

Key Observations: Transmission Line Ratings

- We estimated the potential economic value of using ambient-adjusted ratings on an hourly basis in both day-ahead and real-time markets for 2019 and 2020.
  - The estimated potential cost savings are $15 and $8 million in the day-ahead market for 2019 and 2020, respectively, and $11 and $9 million in the real-time market.
    - The Central-East interface is not evaluated as it uses a voltage collapse limit. Likewise, transmission facilities in New York City and Long Island are excluded because most of them are underground cables, whose ratings are affected by ambient air temperature in a different way than for overhead lines.
  - The estimated cost savings are roughly 9 percent of day-ahead congestion values on the examined transmission facilities and 6 to 7 percent of real-time congestion values.
- The majority of the estimated benefits would come from increased transmission flows through the West Zone and from the North Zone to central New York because these areas frequently exhibit congestion during off-peak hours and shoulder months when ambient temperatures tend to be lowest relative to the seasonal ratings. Therefore, using AARs would likely allow higher production from hydroelectric and wind generation in these areas and increased imports from Ontario and Quebec.

- However, it is noted that these estimates are developed:
  - Using actual temperature rather than forecast temperature;
  - Assuming a linear relationship between ambient-adjusted rating factor and ambient temperature, which may not be accurate for certain conductor types under certain temperature conditions; and
  - Ignoring other important weather parameters that also impact thermal ratings, such as wind speed.
  - Despite these caveats, this evaluation suggests a potential economic value in the neighborhood of $10 million each year with the implementation of AAR in the day-ahead and real-time markets. Moreover, this potential is likely to increase if higher penetration of intermittent renewables leads to more frequent congestion.

H. 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* [301] – 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-64: TCC Cost and Profit by Auction Round and Path Type

Figure A-64 summarizes TCC cost and profit for the Winter 2019/20 and Summer 2020 Capability Periods (i.e., the 12-month period from November 2019 through October 2020). The

301 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.

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 2019/20 Capability Period; (c) four rounds of six-month auctions for the Summer 2020 Capability Period; and (d) twelve Balance-of-Period auctions for each month of the 12-month Capability Period.[302] The figure only evaluates the TCCs that were purchased by Market Participants in these auctions.

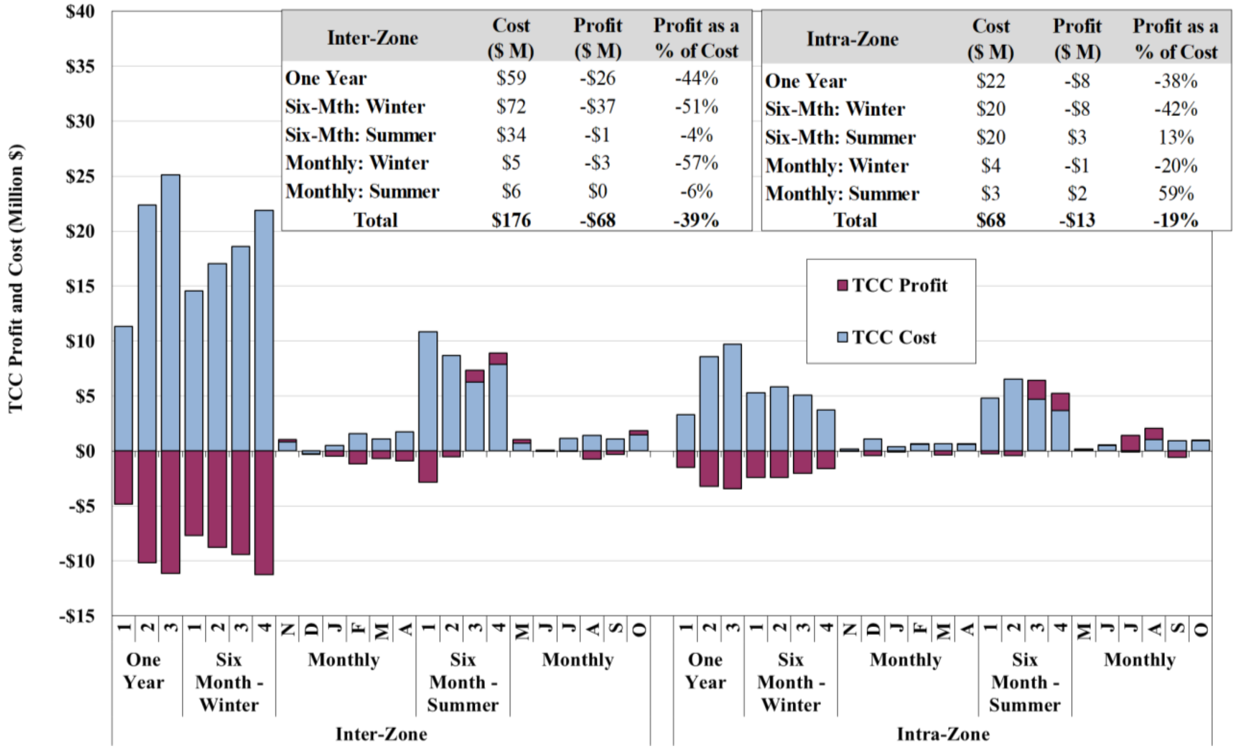
For the purposes of the figure, each TCC is broken into inter-zonal and intra-zonal components, making it possible to identify portions of the transmission system that generate the most revenue in the TCC auction and that are most profitable for the buyers of TCCs. Each TCC has a Point-Of-Injection ("POI") 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.[303]

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.

302 In the figure, the bars in the 'Monthly' category represent aggregated values for the same month from all applicable BOP auctions.

303 For example, a 100 MW TCC from Indian Point 2 to Arthur Kill 2 is unbundled to three components: (a) A 100 MW TCC from Indian Point 2 to Millwood Zone; (b) A 100 MW TCC from Millwood Zone to New York City Zone; and (c) A 100 MW TCC from New York City Zone to Arthur Kill 2. Components (a) and (c) belong to the intra-zone category and Component (b) belongs to inter-zone category.

Figure A-64: TCC Cost and Profit by Auction Round and Path Type
Winter 2019/20 and Summer 2020 Capability Periods



Inter-Zone	Cost ($ M)	Profit ($ M)	Profit as a % of Cost
One Year	$59	-$26	-44%
Six-Mth: Winter	$72	-$37	-51%
Six-Mth: Summer	$34	-$1	-4%
Monthly: Winter	$5	-$3	-57%
Monthly: Summer	$6	$0	-6%
Total	**$176**	**-$68**	**-39%**

Intra-Zone	Cost ($ M)	Profit ($ M)	Profit as a % of Cost
One Year	$22	-$8	-38%
Six-Mth: Winter	$20	-$8	-42%
Six-Mth: Summer	$20	$3	13%
Monthly: Winter	$4	-$1	-20%
Monthly: Summer	$3	$2	59%
Total	**$68**	**-$13**	**-19%**

Table A-2 & Table A-3: 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 2019/20 and Summer 2020 Capability Periods (i.e., the 12-month period from November 2019 through October 2020). 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-2: TCC Cost by Path
Winter 2019/20 and Summer 2020 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	$23	-$14	-$9	-$1	$0	$0	$12	$0	$0	$0	$0	-$1	$0	$0	$0	**$9**
GENESE	$3	$0	$2	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	**$5**
CENTRL	$27	-$3	$18	-$2	$0	$0	$23	$0	$0	$0	$0	$0	$0	$0	$0	**$64**
MHK VL	$15	-$1	$2	-$8	-$5	$2	$1	$0	$0	$0	$0	$0	$0	$1	$0	**$8**
NORTH	$1	$3	$3	$31	$0	$0	$0	$0	$0	$0	$0	$0	$2	$0	$0	**$40**
CAPITL	$0	$0	$0	-$2	$0	$12	-$9	$0	-$2	$0	$0	$0	$0	$3	$0	**$1**
HUD VL	$1	$0	-$3	$0	$0	$9	$4	$2	$3	$27	$0	$0	$0	$30	$0	**$71**
MILLWD	$0	$0	$0	$0	$0	$0	-$1	$1	$1	$0	$0	$0	$0	$0	$0	**$2**
DUNWOD	$0	$0	$0	$0	$0	$0	$0	$0	$0	$1	$1	$0	$0	$0	$0	**$1**
N.Y.C.	$0	$0	$0	-$1	$0	$0	-$2	$0	-$3	$11	$1	$0	$0	$0	$0	**$7**
LONGIL	$0	$0	$0	-$1	$0	$0	$0	$0	$0	-$1	$8	$0	$0	$0	$0	**$4**
O H	$5	$1	$0	$0	$0	$0	$2	$0	$0	$0	$0	$0	$0	$0	$0	**$8**
H Q	$2	$0	$1	$18	-$1	$0	$0	$0	$0	$0	$0	$0	-$1	$0	$0	**$20**
NPX	$0	$0	$0	$0	$0	$0	-$1	-$1	$0	$0	$0	$0	$0	$0	$0	**-$3**
PJM	-$1	$0	-$5	$0	$0	$0	$10	$0	$1	$1	$0	$0	$0	$0	$0	**$6**
Total	**$75**	**-$14**	**$10**	**$35**	**-$7**	**$23**	**$38**	**$3**	**$0**	**$39**	**$10**	**-$2**	**$0**	**$33**	**$0**	**$244**

Table A-3: TCC Profit by Path
Winter 2019/20 and Summer 2020 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	-$6	$6	$2	$0	$0	$0	-$6	$0	$0	$0	$0	$0	$0	$0	$0	**-$3**
GENESE	-$1	$0	-$1	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	**-$3**
CENTRL	-$7	$2	-$9	$1	$0	$0	-$10	$0	$0	$0	$0	$0	$0	$0	$0	**-$23**
MHK VL	-$4	$2	-$1	$2	$1	-$1	$0	$0	$0	$0	$0	$0	$0	$0	$0	**$0**
NORTH	$0	-$1	-$1	-$6	$1	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	**-$8**
CAPITL	$0	$0	$0	$1	$0	-$4	$3	$0	$0	$0	$0	$0	$0	$0	$0	**$0**
HUD VL	$0	$0	$1	$0	$0	-$3	-$1	-$1	-$2	-$17	$0	$0	$0	-$15	$0	**-$39**
MILLWD	$0	$0	$0	$0	$0	$0	$0	$0	-$2	$0	$0	$0	$0	$0	$0	**-$2**
DUNWOD	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	**$0**
N.Y.C.	$0	$0	$0	$0	$0	$0	$1	$0	$2	-$2	$1	$0	$0	$0	$0	**$3**
LONGIL	$0	$0	$0	$0	$0	$0	$0	$0	$0	-$1	$8	$0	$0	$0	$0	**$6**
O H	-$2	$0	$0	$0	$0	$0	-$1	$0	$0	$0	$0	$0	$0	$0	$0	**-$3**
H Q	$0	$0	-$1	-$7	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	**-$8**
NPX	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	**$1**
PJM	$1	$0	$2	$0	$0	$0	-$3	$0	-$1	$0	$0	$0	$0	$0	$0	**-$1**
Total	**-$20**	**$9**	**-$6**	**-$9**	**$2**	**-$9**	**-$17**	**-$1**	**-$3**	**-$21**	**$10**	**$1**	**$1**	**-$15**	**$0**	**-$81**

Key Observations: TCC Prices and Profitability

- TCC buyers netted a total loss of $81 million in the TCC auctions during the reporting 12-month period (November 2019 to October 2020), resulting in an average profitability (profit as a percent of TCC cost) of negative 33 percent.[304]
  - TCC buyers netted an average *loss* of 39 percent on the inter-zonal transmission paths and an average *loss* of 19 percent on the intra-zonal paths.
- TCC profitability coincided with changes in the congestion pattern from the prior year.

304 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 2019 and 2020. 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 2019 to October 2020.

- Low natural gas prices and unexpectedly low load levels because of the COVID-19 pandemic led to a historical-low level of congestion in 2020, which was not anticipated by market participants.
  - As a result, TCC buyers netted a loss on most transmission paths.
  - TCC buyers netted the largest loss of $21 million on transmission paths sinking at New York City (from a $39 million purchase cost). The commercial load in New York City was greatly impacted by the pandemic and the resulting decrease in congestion was unanticipated.
  - TCC buyers also netted a $20 million loss from a $75 million purchase cost on transmission paths sinking at the West Zone. This coincided with a 40 percent reduction in day-ahead congestion in the West Zone (for the reasons discussed in subsection B).
  - However, transmission paths sinking on Long Island were an exception, where TCC buyers netted a $10 million profit from a $10 million purchase cost. This coincided with a 10 percent increase in day-ahead congestion on Long Island because of: a) unexpected lengthy transmission outages at the Cross Sound Cable interface, the Neptune interface, and the Y49 line; and b) higher residential load in Long Island resulting from the pandemic.
- These results indicate that:
  - Market participants' anticipated congestion levels were generally in line with the levels observed in the prior year.
  - Unexpected congestion-driven events, such as lengthy unplanned outages and large variations in load patterns, play a key role in TCC profitability.

I. Potential Design of Financial Transmission Rights for PAR Operation

This subsection describes how a financial right could be created to compensate ConEd if the lines between NYC and Long Island were scheduled efficiently (rather than according to a fixed schedule) in accordance with Recommendation #2012-8, which is described in Section XI. An efficient financial right should compensate ConEd: (a) in accordance with the marginal production cost savings that result from efficient scheduling, and (b) in a manner that is revenue adequate such that the financial right should not result in any uplift for NYISO customers. Note, this new financial transmission right would not alter the TCCs possessed by any market party.

Concept for Financial Transmission Right

An efficient financial right should compensate ConEd for the quantity of congestion relief provided at a price that reflects the marginal cost of relieving congestion on each flow gate in the day-ahead and real-time markets. These are the same principles upon which generators are paid and load customers are charged. Hence, a transmission right holder should be paid:

DAM Payment =

$$\sum_{l=901,903}\left([DAM\ MW_l - TCC\ MW_l] \times \sum_{c=constraint}\left[-DAM\ SF_{l,c} \times DAM\ SP_c\right]\right)$$

RTM Payment =

$$\sum_{l=901,903}\left([RTM\ MW_l - DAM\ MW_l] \times \sum_{c=constraint}\left[-RTM\ SF_{l,c} \times RTM\ SP_c\right]\right)$$

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:

- Basecase Scenario – Provides an example of the current market rules where the NYISO receives revenues from loads that exceed payments to generators, thereby contributing to DAM congestion revenues.

- PAR Relief Scenario – Shows how a PAR-controlled line could be used to reduce congestion, allowing the owner of the line to be compensated without increasing uplift from DAMCRs.
- PAR Loading Scenario – Shows how the owner of the line would be charged if the DAM schedule increased congestion relative to the TCC schedule assumption.

These scenarios use a simplified four node network, including: Upstate, NYC, Valley Stream, and Rest of Long Island. The four nodes are interconnected by four interfaces:

- The Dunwoodie interface from Upstate to NYC,
- The Y50 Line from Upstate to Rest of Long Island,
- The 262 Line from Rest of Long Island to Valley Stream, and
- The PAR-controlled 901 Line from Valley Stream to NYC.

For simplicity, the 901 Line contract amount that is used in the TCC auction is rounded to 100 MW.

The Base Case Scenario shows that a net of $22,500 of DAM congestion revenue is collected from scheduling by generators and loads. The table also shows the amount of DAM congestion revenue that accrues on each constrained facility. In this example, DAMCR equals $0 because the flows on each constrained facility are equal to the capability/assumption in the TCC model. Since the 901 Line contract moves power from a high LBMP area to a low LBMP area, it reduces congestion revenue by $2,000, but it does not cause DAMCR because it is consistent with the TCC auction.

The PAR Relief Scenario shows that if the 901 Line flow is reduced from 100 MW to 10 MW, it reduces the generation needed in Valley Stream and increases generation in NYC, reducing overall production costs by $1,800 as compared to the Basecase Scenario. Since LBMPs do not change in this example, payments by loads are unchanged and $1,800 of additional congestion revenues are collected. The collection of additional congestion revenues allows the NYISO to compensate ConEd $1,800 for the PAR adjustment, and DAMCR remains at $0.

The PAR Relief Scenario shows that if the 901 Line flow is increased from 100 MW to 120 MW, it increases the generation needed in Valley Stream and reduces generation in NYC, increasing overall production costs by $400 as compared to the Basecase Scenario. Since LBMPs do not change in this example, payments by loads are unchanged and $400 less congestion revenue is collected. The collection of less congestion revenue requires the NYISO to charge ConEd $400 for exceeding the contract amount, and DAMCR remains at $0.

BASECASE SCENARIO

	Node	LBMP	Load	Generation	Load Revenue	Generator Payments
Gen/Load Payments	Upstate	$25	10000	13000	$250,000	$325,000
	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 Revenue	Dunwoodie	$5	2000	$10,000
	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 Payments	Upstate	$25	10000	13000	$250,000	$325,000
	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 Revenue	Dunwoodie	$5	2000	$10,000
	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 Payments	Upstate	$25	10000	13000	$250,000	$325,000
	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 Revenue	Dunwoodie	$5	2000	$10,000
	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.[305,306] 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 cost 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.

305 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.

306 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-65 to Figure A-68 : 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 2019 and 2020. 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-65, the primary interfaces with Quebec and New England in Figure A-66, and the controllable lines connecting Long Island and New York City with PJM and New England in Figure A-67 and Figure A-68.

Figure A-65: Monthly Average Net Imports from Ontario and PJM
2019 – 2020

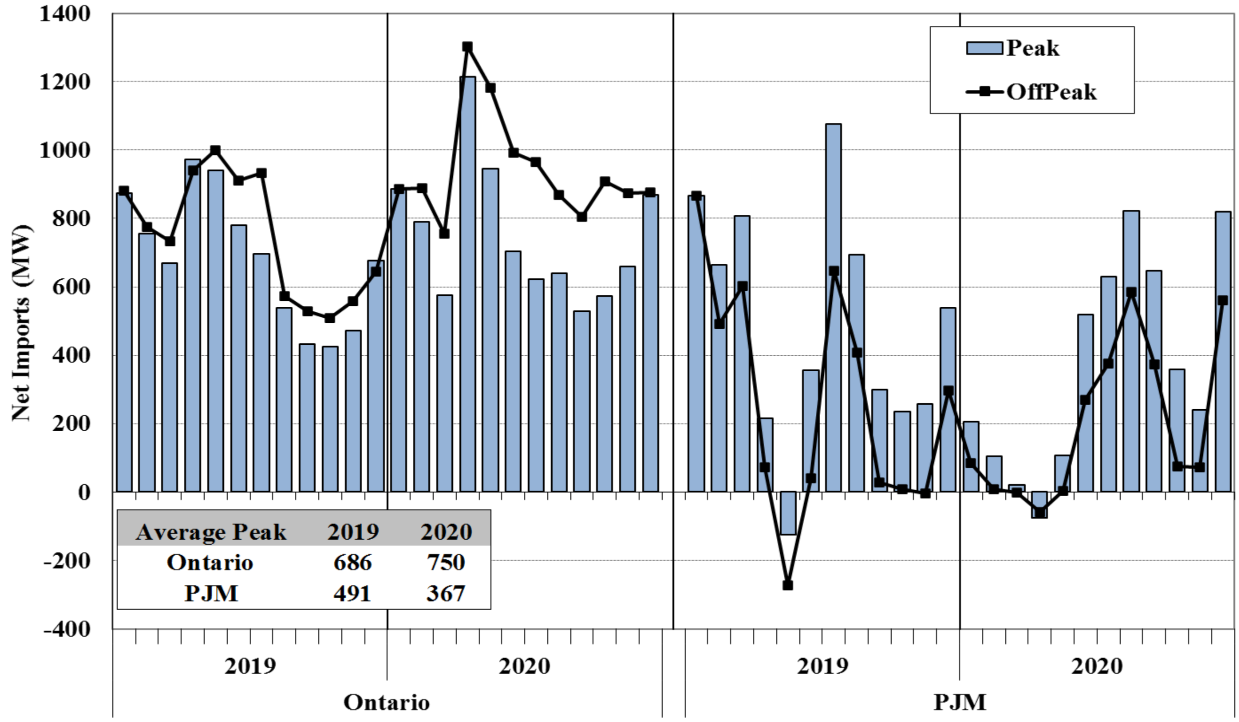


Figure A-66: Monthly Average Net Imports from Quebec and New England
2019 – 2020

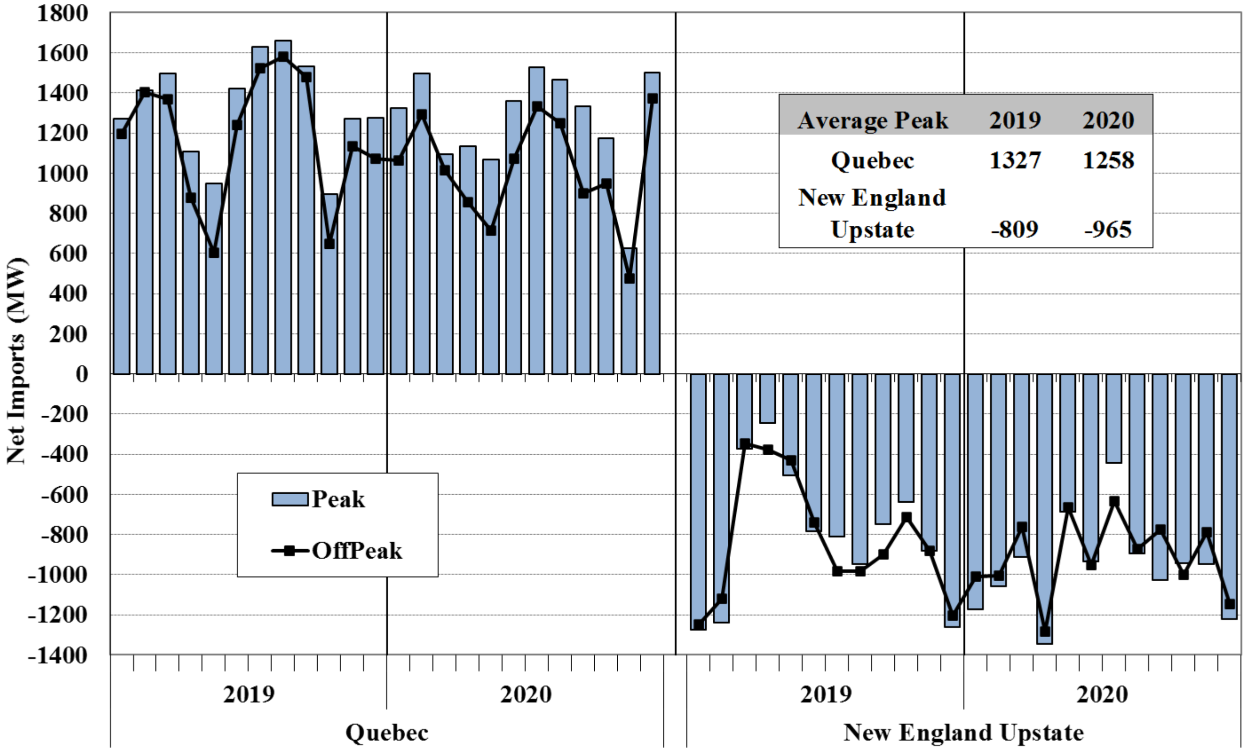


Figure A-67: Monthly Average Net Imports into New York City
2019 – 2020

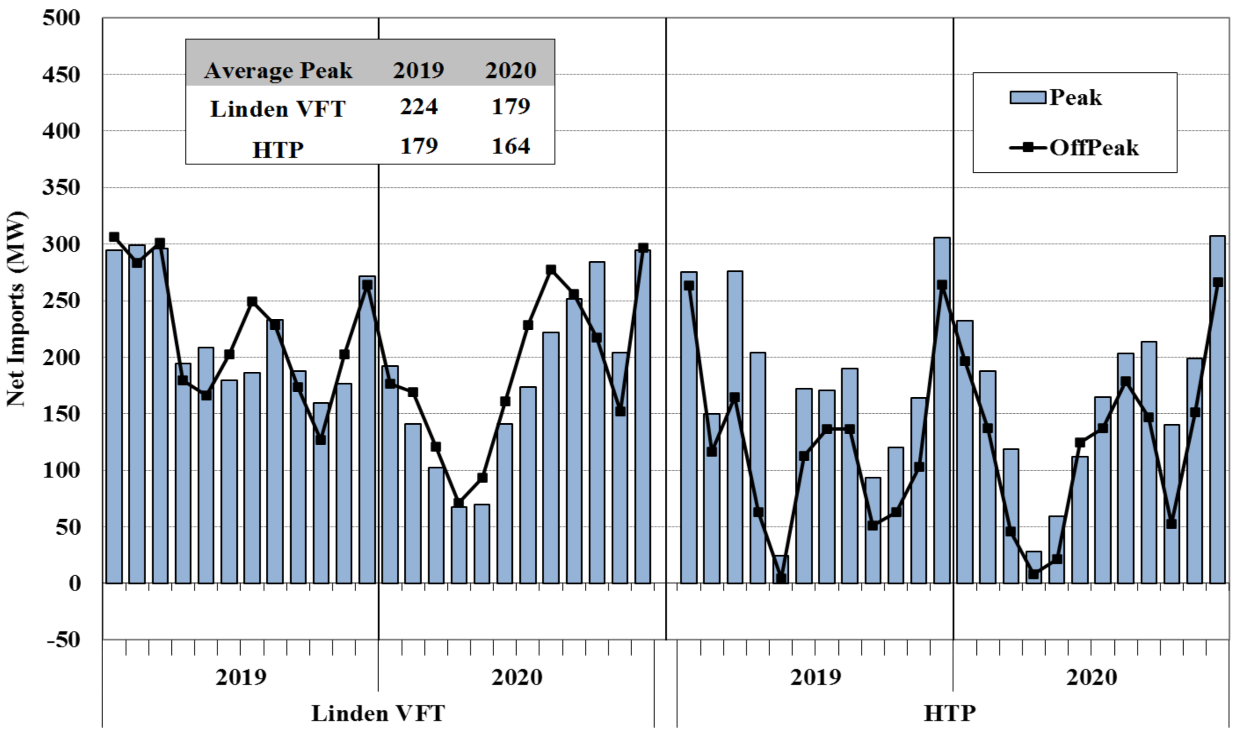
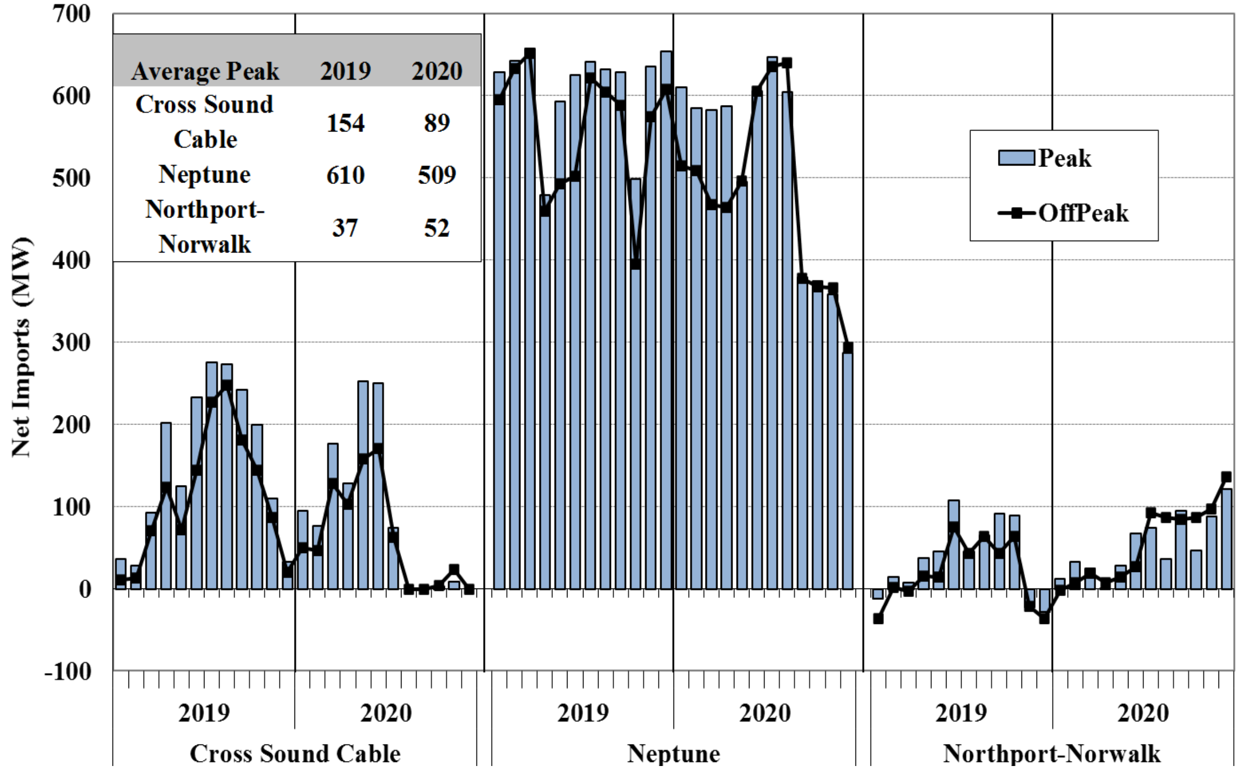


Figure A-68: Monthly Average Net Imports into Long Island
2019 – 2020



Key Observations: Average Net Imports

- Total net imports averaged roughly 2,400 MW during peak hours in 2020, down 17 percent from 2019.
  - Net imports served approximately 13 percent of load in 2020.
  - The reduction in net imports from 2019 was due partly to variations in transmission outages.
    - Net exports to New England rose as a result of fewer transmission outages at the interface in 2020; and
    - Net imports into Long Island fell as a result of lengthy transmission outages at the CSC (from August to December) and Neptune (from September to December) interfaces in 2020.
- Average net imports from neighboring areas across the primary interfaces fell nearly 17 percent from about 1,695 MW in 2019 to 1,410 MW in 2020 during the peak hours.
  - Net imports from Quebec averaged roughly 1,260 MW, accounting for 89 percent of net imports across the primary interfaces in 2020 during the peak hours . Imports from Quebec were high in most months of 2020 but fell notably in several shoulder months (e.g., March, November) because of transmission outages.

  - Net imports from Ontario rose modestly in 2020, reflecting less transmission congestion from west-to-east through the West Zone.
  - 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 (e.g., PJM < New York < New England).
    - Net exports to New England increased 19 percent from 2019 to 2020, also reflecting fewer lengthy transmission outages at the interface in 2020. In 2019, the Long Mountain-Pleasant Valley 345 kV line had a lengthy outage from early March to late May, during which the NY/NE interface limit was reduced to around 700 MW; while in 2020, there were no similar lengthy outages.

- Net imports from neighboring areas into Long Island over the three controllable interfaces averaged roughly 650 MW during peak hours in 2020, down 19 percent from 2019.
  - The decrease occurred primarily at the Neptune and Cross Sound interfaces because of due to lengthy transmission outages at the two interfaces in the second half of 2020. The Cross Sound Cable was completely out of service from August to December and the Neptune interface was partially derated to 375 MW from September to December.
  - Despite the reduction, imports over the three controllable interfaces still accounted for a large share of the supply to Long Island, serving 27 percent of the load in Long Island in 2020.

- Average net imports from New Jersey to New York City over the Linden VFT and the HTP interfaces averaged 340 MW during peak hours in 2020, down 15 percent from 2019.
  - The decrease 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 would not be willing 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-69: Price Convergence Between New York and Adjacent Markets

Figure A-69 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-69 summarizes price differences between New York and neighboring markets during unconstrained hours in 2020. 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.[307] 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.

[307] In these hours, prices in neighboring RTOs (i.e., prices at the NYISO proxy in each RTO market) reflect transmission constraints in those markets.

Figure A-69: Price Convergence Between New York and Adjacent Markets
Unconstrained Hours in Real-Time Market, 2020

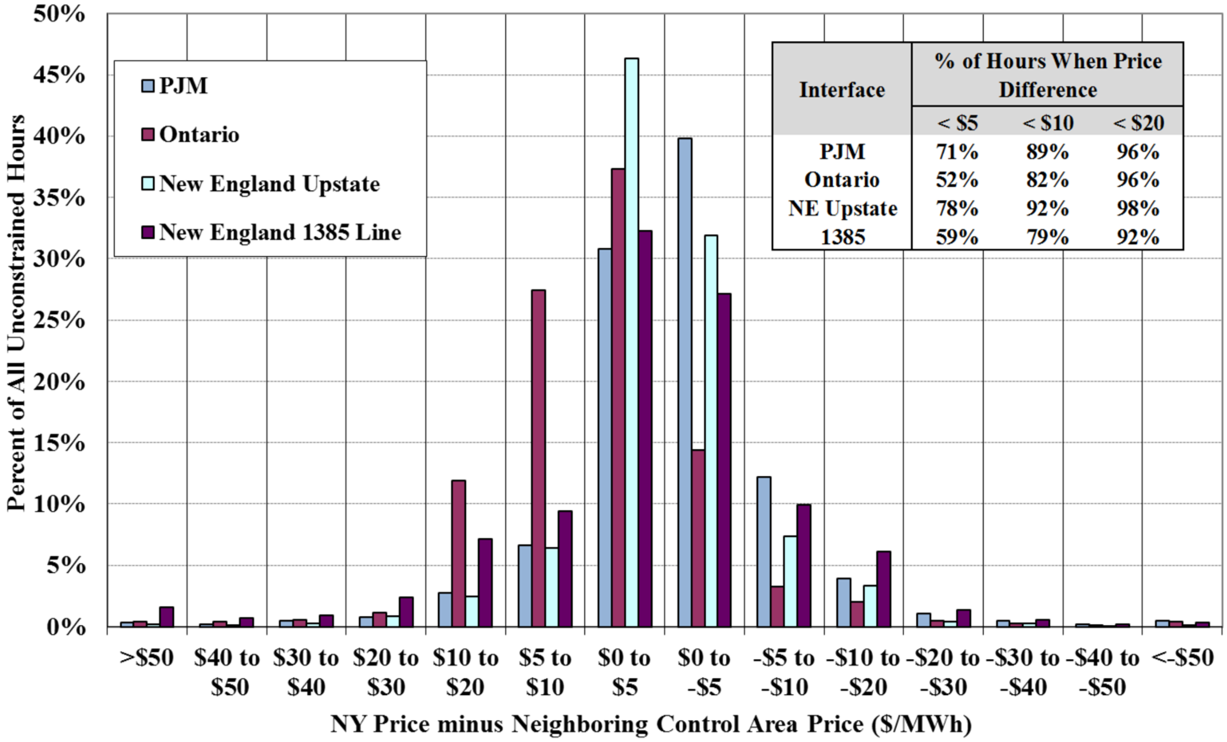


Table A-4: Efficiency of Inter-Market Scheduling

Table A-4 evaluates the consistency of the direction of external transaction scheduling and price differences between New York and New England, PJM, and Ontario during 2020. It evaluates transaction schedules and clearing prices between New York and the three markets across the three primary interfaces and five scheduled lines (i.e., the 1385 Line, the Cross Sound Cable, the Neptune Cable, the HTP Line, and the Linden VFT interface).

The table shows the following quantities:

- 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.[308]

308 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.

- 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 of the interface. [309]
- 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.[310]

Table A-4 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.

Table A-4: Efficiency of Inter-Market Scheduling
Over Primary Interfaces and Scheduled Lines – 2020

	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	-1,061	$0.18	45%	-$1	128	$0.68	52%	$1
Ontario	904	$4.95	87%	$43	-53	$4.45	48%	$0.0
PJM	308	-$0.33	60%	$4	-29	-$1.13	57%	$2
Controllable Ties								
1385 Line	69	$2.07	75%	$2	-15	$1.26	54%	$0.2
Cross Sound Cable	72	$7.27	77%	$2	3	$7.30	50%	$0.1
Neptune	497	$7.43	92%	$28	-3	$6.97	50%	$0.3
HTP	75	$2.07	86%	$2	68	$1.37	71%	$2
Linden VFT	92	$2.61	95%	$4	90	$1.79	71%	$3

309 The real-time Hourly Ontario Energy Price ("HOEP") is used at the Ontario side of the interface for both the day-ahead and real-time markets.

310 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.

Key Observations: Efficiency of Inter-Market Scheduling

- Price differences across New York's external interfaces were smaller in 2020 than in 2019, partly driven by lower load levels and lower and less volatile gas prices.
  - For example, the portion of unconstrained hours when the price difference at the border was less than $5/MWh increased from 44 percent at the Ontario interface and 70 percent at the New England interface in 2019 to 52 percent and 78 percent in 2020. (see table in Figure A-69).
  - Similar to prior years, price differences at the CTS interfaces (PJM and ISO-NE) remained smaller than for the hourly-scheduled Northport-to-Norwalk and Ontario interfaces (see table in Figure A-69).
    - This indicates that CTS has generally improved the utilization of the interfaces.
  - Similarly, the price differences at the CTS interface with ISO-NE continued to be smaller than the price differences at the CTS interface with PJM.
    - This is at least in part due to the better performance of CTS with ISO-NE.
    - Table A-4 shows a smaller estimated production cost savings at the NY/NE border than at the NY/PJM border. Because the calculation does not consider how the scheduling of the interface raises or lowers the marginal production costs of internal resources, it does not capture most of the production cost savings at interfaces where there are small price differentials between markets. Therefore, the lower estimated savings at the interface with ISO-NE reflects that it is the better arbitraged interface.
    - The internal price in real-time was lower on average than on the PJM side of the interface. This is partly because the fees to export from NYISO to PJM are significantly higher than to export from PJM to NYISO, reducing the liquidity of transactions capable of arbitrage when the PJM price is higher than in NYISO.
- Nonetheless, the price differences were still widely distributed and a substantial number of unconstrained hours (8 to 21 percent) had price differences exceeding $10/MWh for every interface in 2020.
  - Although these results improved from the 12 to 27 percent in 2019, they still 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 2020.
- 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

Coordinated Transaction Scheduling ("CTS") allows two wholesale market operators exchange information about their internal prices shortly before real-time, which can be used to assist market participants in scheduling external transactions more efficiently. The CTS intra-hour scheduling system has at least two advantages over hourly LBMP-based scheduling:

- 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-70: Bidding Patterns of CTS at the Primary PJM and NE Interfaces

The first analysis examines the trading volumes of CTS transactions in 2020. In particular, Figure A-70 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 2020. 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.[311] 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:

311 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 at the border. 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 at the border less (b) the bid price.

- 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 2020.

Figure A-70: Price-Sensitive Real-Time Transaction Bids and Offers by Month

PJM and NE Primary Interfaces, 2020

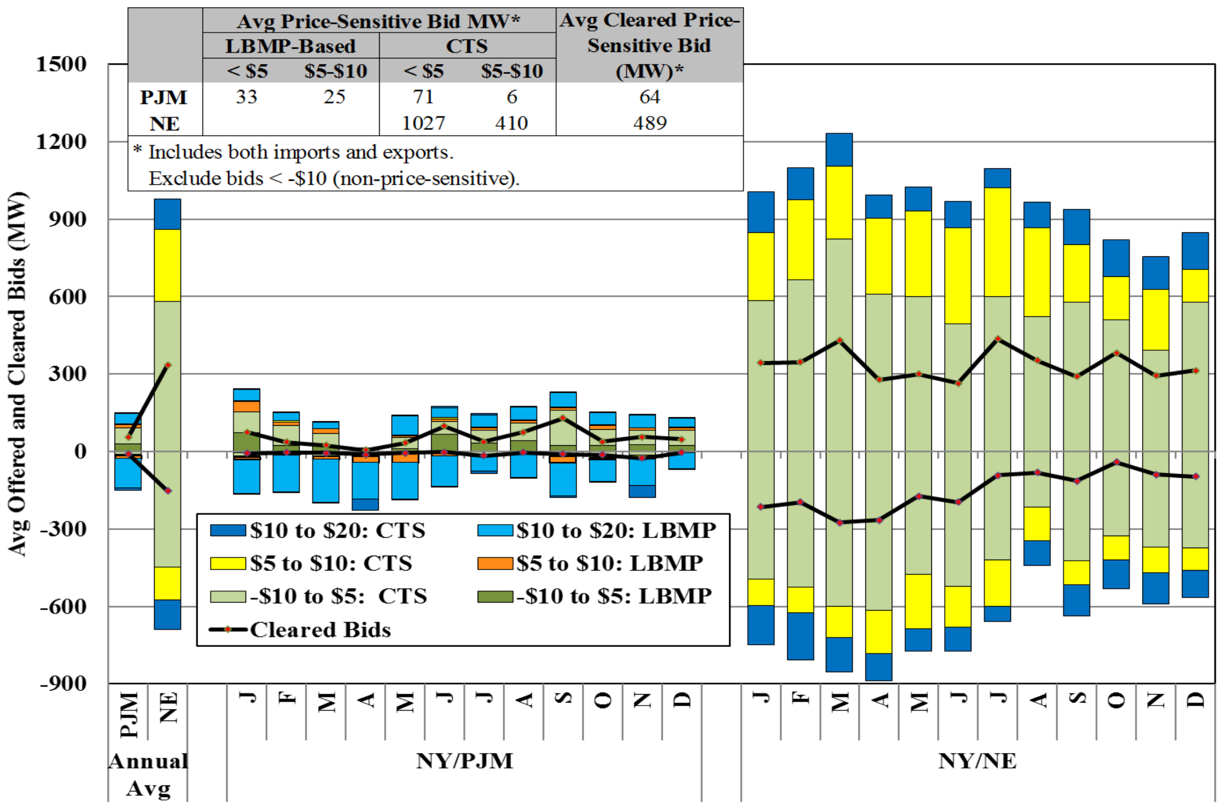


Figure A-71: Transaction Profitability at the Primary PJM and NE Interfaces

The second analysis examines the profitability of scheduled transactions at the two CTS-enabled interfaces. In the bottom portion of Figure A-71, the column bars indicate the profitability spread of the middle two quartiles (i.e, 25 to 75 percentile) in 2020. 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 two groups:

- *Day-ahead* – Transactions that are scheduled in the day-ahead market and actually flow in real-time. This excludes virtual imports and exports, which have a day-ahead schedule but do not bid/offer in real-time.

- *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).

The bars in the top portion of the figure show the average quantity of scheduled transactions for each category in 2020 and the inset table summarizes the annual average profit.

Figure A-71: Profitability of Scheduled External Transactions
PJM and NE Primary Interfaces, 2020

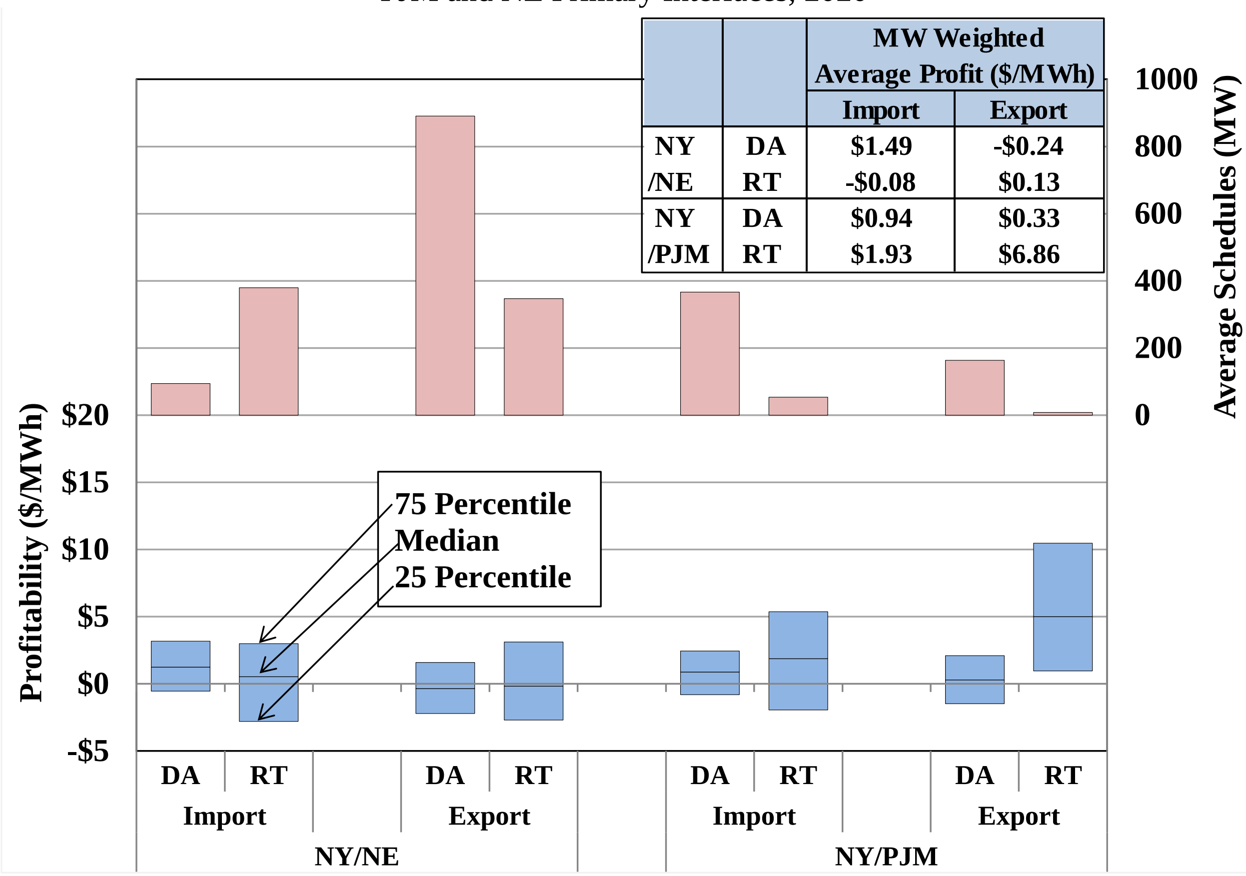


Table A-5: Efficiency of Intra-Hour Scheduling Under CTS

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. [312]

Table A-5 examines the performance of the intra-hour scheduling process under CTS at the primary PJM and New England interfaces in 2020. 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.[313]
    - Net Over-Projected Savings – This estimates production cost savings that are over-projected. CTS bids are scheduled based partly on forecast prices. If forecast prices deviate from actual prices, transactions may be over-scheduled, under-scheduled, and/or scheduled in the inefficient direction. This estimates the portion of savings that inaccurately projected because of PJM, NYISO, and ISO-NE forecast errors. [314]
    - Other Unrealized Savings – This measures production cost savings that are not realized once the following factors are taken into account:

312 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.

313 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 318.

314 This is calculated as: a) (final RTC schedule – estimated hourly schedule)*(RTD price – RTC price) for NYISO forecast error; b) (final RTC schedule – estimated hourly schedule)*(PJM forecast price – PJM RT price) for PJM forecast error; and c) (final RTC schedule – estimated hourly schedule)*(NE forecast price – NE RT price) for NE forecast error.

   - Real-time Curtailment[315] - 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[316] - 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-73). 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[317,318] – This is equal to (Projected Savings – Net Over-Projected Savings - Unrealized Savings).

- Interface Prices – These show actual real-time prices and forecasted prices at the time of RTC scheduling.

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315 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).

316 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).

317 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).

318 The marginal cost of production is estimated from LBMPs that result from scheduling a transaction, but the marginal cost of production varies as the interface schedule is adjusted. For example, if 100 MW is scheduled to flow from PJM or NE to NYISO, reducing the price spread between markets from $12/MWh to $5/MWh, our unadjusted production cost savings estimate from the transaction would be $500/hour (= 100 MW x $5/MWh). However, if the change in production costs was linear in this example, the true savings would be $850/hour (= 100 MW x Average of $5 and $12/MWh). We make a similar adjustment to our estimate of marginal cost of production assuming that: a) the supply curve was linear in all three markets; b) at the NY/PJM border, a 100 MW movement in the supply curve changes the marginal cost by 7.5 percent of NY LBMP in the New York market and 2.5 percent of PJM LBMP in the PJM market; and c) at the NY/NE border, a 100 MW movement in the supply curve changes the marginal cost by 15 percent of NY LBMP in the New York market and 5 percent of NE LBMP in the NE market.

- 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-5: Efficiency of Intra-Hour Scheduling Under CTS

Primary PJM and New England Interfaces, 2020

			Average/Total During Intervals w/ Adjustment					
			CTS - NY/NE			CTS - NY/PJM		
			Both Forecast Errors <= $20	Any Forecast Error > $20	Total	Both Forecast Errors <= $20	Any Forecast Error > $20	Total
% of All Intervals w/ Adjustment			75%	4%	**78%**	26%	4%	**30%**
Average Flow Adjustment (MW)	Net Imports		21	25	**21**	0	-31	**-5**
	Gross		108	145	**110**	56	99	**62**
Production Cost Savings ($ Million)	Projected at Scheduling Time		$3.4	$1.0	**$4.4**	$0.5	$1.2	**$1.7**
	Net Over-Projection by:	NY	-$0.3	-$0.4	**-$0.7**	-$0.1	-$0.3	**-$0.3**
		NE or PJM	$0.0	-$0.1	**$0.0**	-$0.2	-$0.9	**-$1.1**
	Other Unrealized Savings		-$0.1	-$0.1	**-$0.2**	$0.0	$0.0	**$0.0**
	Actual Savings		$2.9	$0.5	**$3.4**	$0.3	$0.1	**$0.3**
Interface Prices ($/MWh)	NY	Actual	$19.08	$55.48	**$20.75**	$18.93	$41.31	**$22.22**
		Forecast	$20.45	$49.09	**$21.76**	$21.11	$43.21	**$24.36**
	NE or PJM	Actual	$19.60	$49.75	**$20.98**	$19.06	$44.56	**$22.81**
		Forecast	$18.75	$43.48	**$19.88**	$20.77	$53.71	**$25.61**
Price Forecast Errors ($/MWh)	NY	Fcst. - Act.	$1.37	-$6.39	**$1.02**	$2.18	$1.90	**$2.14**
		Abs. Val.	$2.69	$41.09	**$4.44**	$3.73	$26.65	**$7.10**
	NE or PJM	Fcst. - Act.	-$0.85	-$6.27	**-$1.10**	$1.71	$9.16	**$2.81**
		Abs. Val.	$2.63	$20.71	**$3.46**	$3.32	$43.84	**$9.27**

Figure A-72 & Figure A-73: Price Forecast Errors Under CTS

The next analysis compares the performance of price forecasting by the three ISOs in the CTS process. Figure A-72 shows the cumulative distribution of forecasting errors in 2020. The price forecast error in each 15-minute period is measured as the absolute value of the difference between the forecast price and actual price. The figure shows the ISO-NE forecast error in two ways: (a) based on the piece-wise linear curve that is produced by its forecasting model, and (b) based on the step-function curve that the NYISO model uses to approximate the piece-wise linear curve. Figure A-73 illustrates this with example curves. [319] 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.

[319] The two curves are forecasted supply curves used in the market on January 5, 2016.

Figure A-72: Distribution of Price Forecast Errors Under CTS
NE and PJM Primary Interfaces, 2020

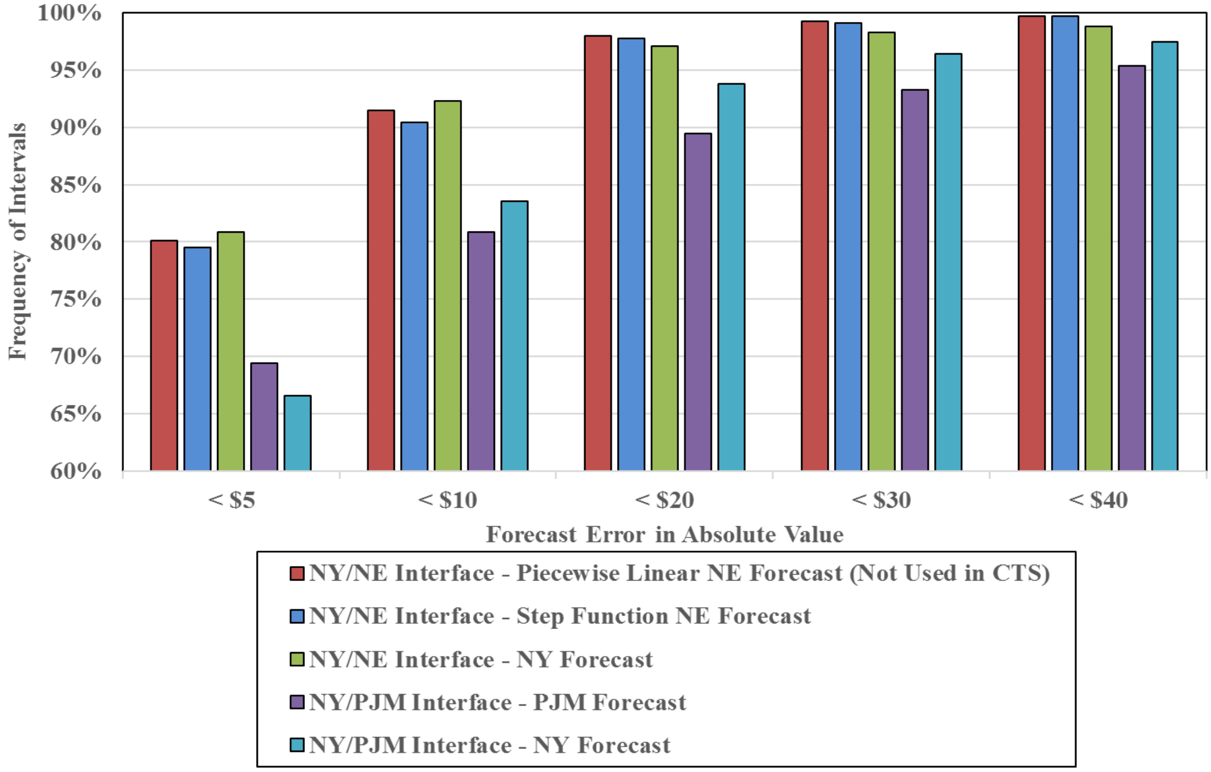
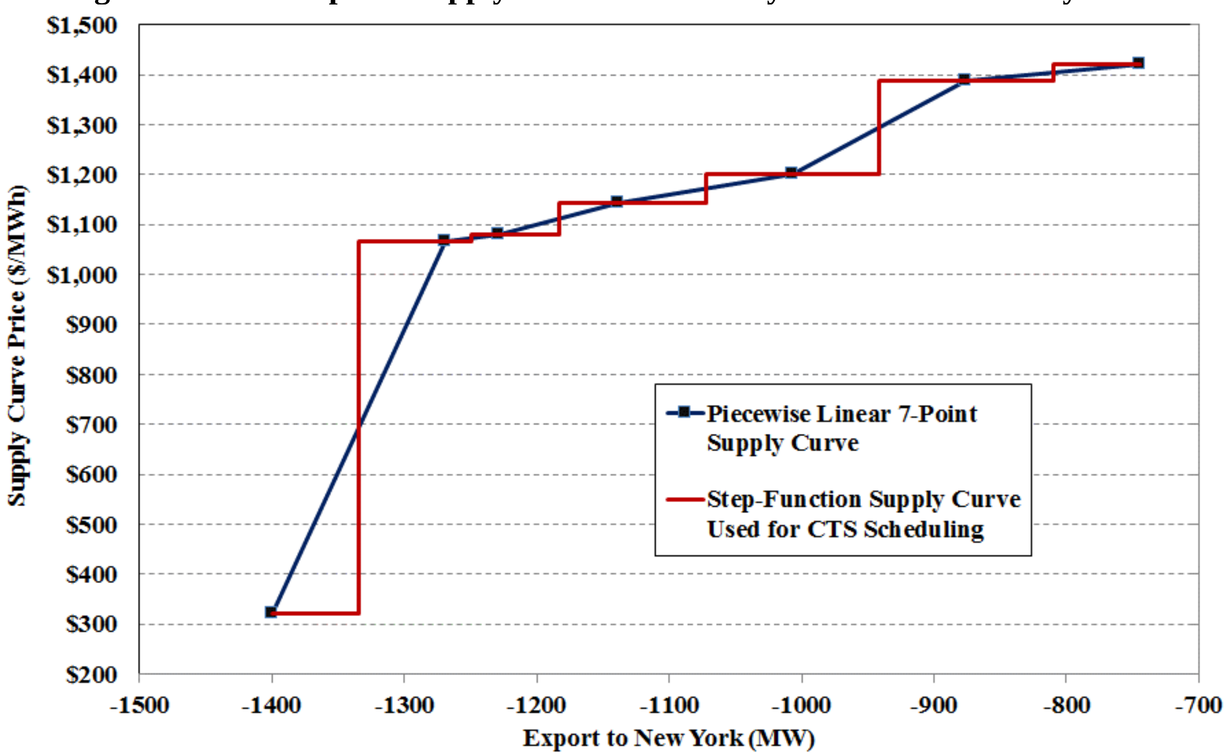


Figure A-73: Example of Supply Curve Produced by ISO-NE and Used by RTC



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-70). In 2020,
    - An average of 1,027 MW (including both imports and exports) were offered between -$10 and $5/MWh at the NY/NE interface, while only 104 MW were offered in this range at the primary NY/PJM interface.
    - Likewise, the amount of cleared price-sensitive bids at NY/NE interface was more than seven times 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 (78 percent of intervals) than at the NY/PJM interface (30 percent of intervals). and
        - The projected production cost saving at the scheduling time was higher at the NY/NE interface ($3.4 million) than at the NY/PJM interface ($0.5 million).[320]
- 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 averaged between $6 and $7/MWh in 2020, while PJM charges physical imports and exports at a rate typically less than $2/MWh.[321]
        - The average profit (not including fees) for real-time exports to PJM was $6.86/MWh in 2020 (see Figure A-71).[322] However, this can barely cover the high charges.
        - Therefore, it is not surprising that almost no CTS export bids at the PJM border were offered at less than $5/MWh (see Figure A-70).
        - In 2020, the average amount of real-time exports scheduled price-sensitively (~10 MW) at the PJM border was much lower than the average amount of real-time imports scheduled price-sensitively (~55 MW). This is primarily because fees are

[320] 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.

[321] In addition, 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.

[322] The vast majority of the day-ahead exports to PJM were scheduled by participants with physical contract obligations and were not necessarily sensitive to these export fees.

significantly higher on transactions scheduled from NYISO to PJM than the opposite direction.

    - The high fees charged on transactions from NYISO to PJM provides a strong disincentive to scheduling exports. Consequently, roughly $0.6 million was collected by NYISO from real-time exports to PJM in 2020. PJM collected an estimated $1.2 million in export fees from real-time exports to NYISO.

  - On the contrary, most of the cleared transactions at the ISO-NE border were offered at less than $5/MWh (see Figure A-70) and their average profit (including both imports and exports) was generally small. (see Figure A-71).
    - This demonstrates that imposing substantial charges on low-margin trading activity has a dramatic effect on the liquidity of the CTS process.
  - 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.
    - 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 were $3.7 million in 2020, most of which accrued at the NY/NE border.
  - The actual production cost savings at the PJM border has been minimal (e.g., $0.7 million in 2018, $0.1 million in 2019, and $0.3 million in 2020) in spite of projected savings of $1.7 million at the scheduling time.
    - A large portion of projected savings occurred during intervals when forecasting errors were significant (i.e., > $20/MWh).
    - Of all price forecasts at the two CTS interfaces, the performance of PJM price forecasts was still the worst in 2020 despite a modest improvement in the forecast errors from 43 percent in 2019 to 41 percent in 2020. (see Figure A-72).

- 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 2020, about 83 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-5).
  - 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-74 & Figure A-75: Patterns in Differences between RTC Forecast Prices and RTD Prices

Figure A-74 shows a histogram of the resulting differences in 2020 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 of the RTD LBMP minus the RTC LBMP;
- The median of the RTD LBMP minus the RTC LBMP; and
- The mean absolute difference between the RTD and RTC LBMPs.

LBMPs are shown at the NYISO Reference Bus location at the quarter-hour intervals for both RTC and RTD.

Figure A-75 summarizes 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 in 100-and-above MW tranches. The upper portion of the figure 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.

Figure A-74: Histogram of Differences Between RTC and RTD Prices and Schedules
2020

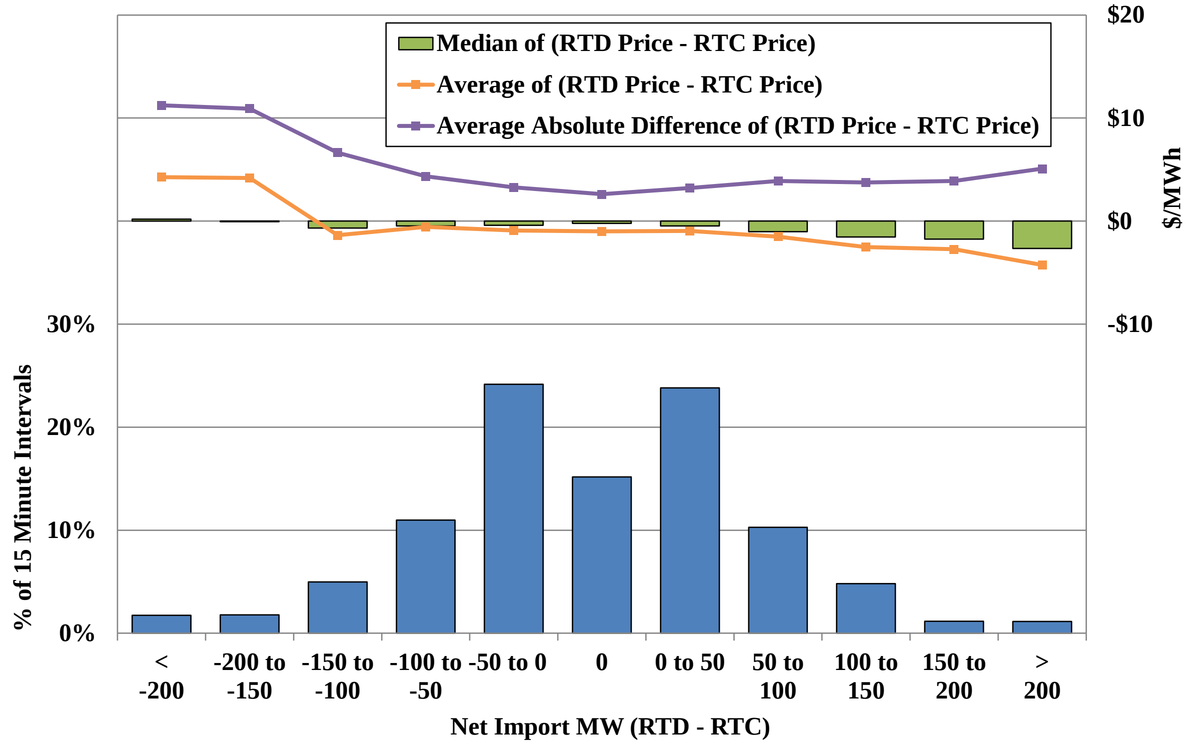


Figure A-75: Differences Between RTC and RTD Prices and Schedules by Time of Day
2020

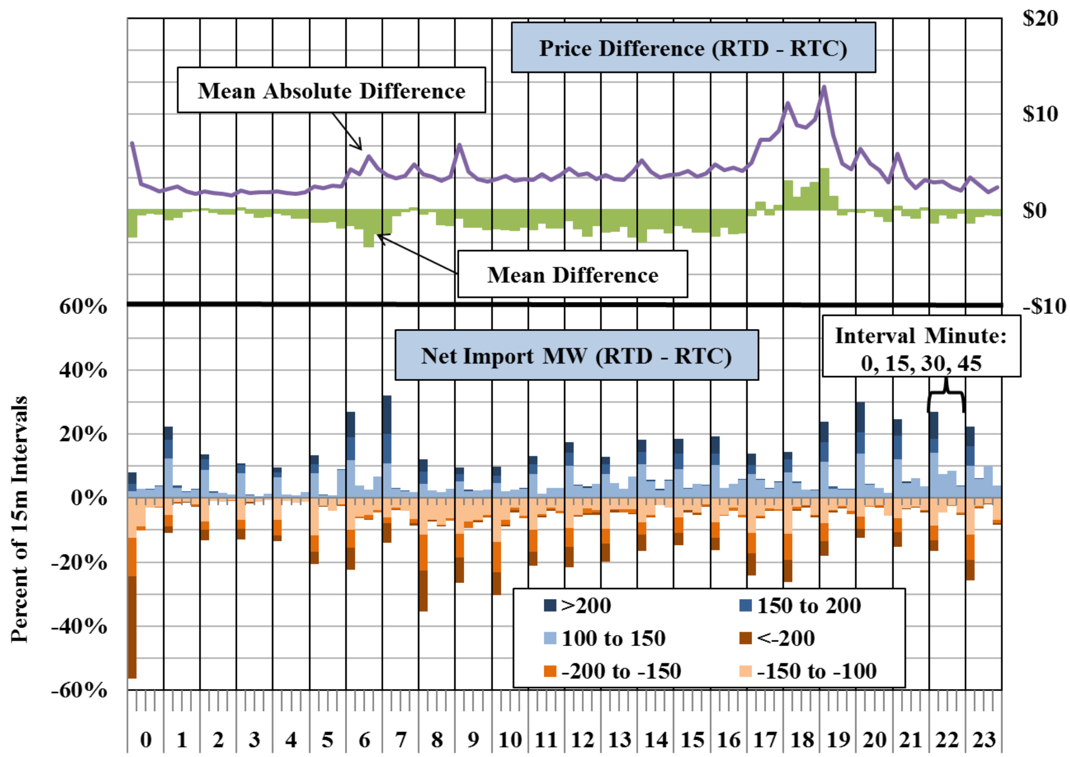


Figure A-76 to Figure A-79: Forecast Assumptions Used by RTC to Schedule CTS Transactions and Their Price Impact

Figure A-76 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. Although inconsistent ramp profile assumptions are not the only source of inconsistent RTC and RTD prices, they illustrate how inconsistent modeling assumptions can lead to inconsistent pricing outcomes.

In RTD, the assumed level of net imports is based on the 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-76: Illustration of External Transaction Ramp Profiles in RTC and RTD

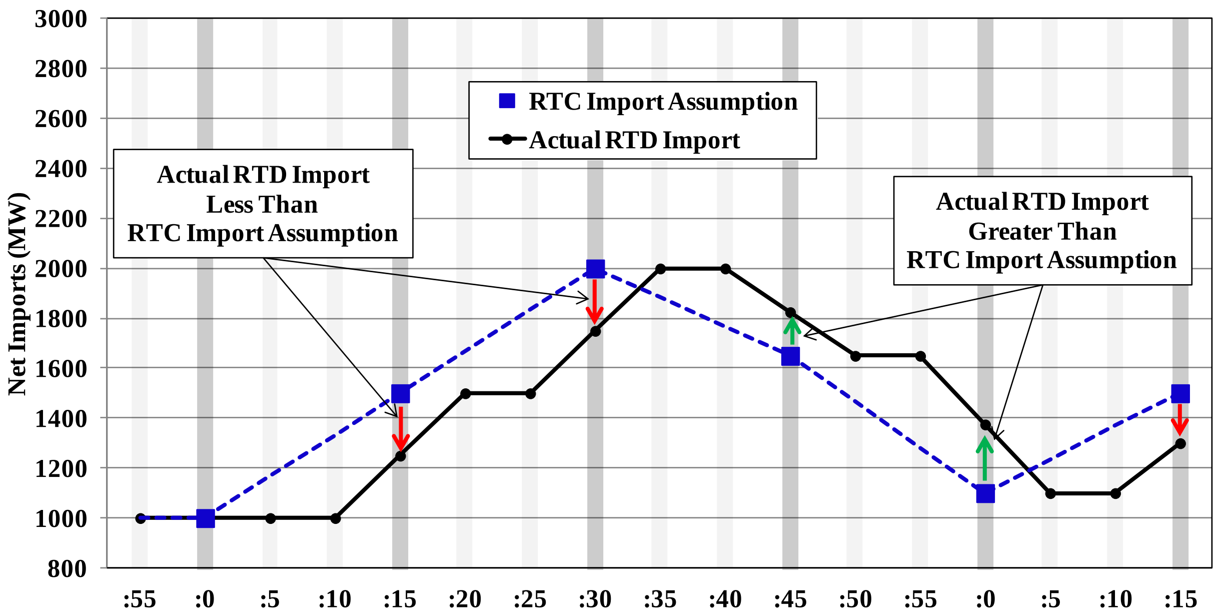


Figure A-77 to Figure A-79 provide the results of our systematic evaluation of factors that lead to inconsistent results in RTC and RTD. This evaluation assesses the magnitude of the contribution of various factors using a metric that is described below. An important feature of this metric is that it 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).[323]

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:

$$\text{Metric}_{i} = (\text{NetInjectionMW}_{i,RTC} - \text{NetInjectionMW}_{i,RTD}) * (\text{Price}_{i,RTC} - \text{Price}_{i,RTD})$$ [324]

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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323 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.

324 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:

$$\text{Metric}_i = (\text{FlowMW}_{i,RTC} - \text{FlowMW}_{i,RTD}) * \sum_c \{(\text{ShadowPrice}_{c,RTC} * \text{ShiftFactor}_{i,c,RTC} - \text{ShadowPriceMW}_{c,RTD} * \text{ShiftFactor}_{i,c,RTD})\}$$

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.[325]

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:

$$\text{Metric\_BindingTx}_c = \text{ShadowPrice}_{c,RTC} * \sum_i \{\text{ShiftFactor}_{i,c,RTC} * (\text{MW}_{i,RTC} - \text{MW}_{i,RTD})\} - \text{ShadowPrice}_{c,RTD} * \sum_i \{\text{ShiftFactor}_{i,c,RTD} * (\text{MW}_{i,RTC} - \text{MW}_{i,RTD})\}$$

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.

325 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, 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-76.

Figure A-77 summarizes the RTC/RTD divergence metric results for detrimental factors in 2020, while Figure A-78 provides the summary for beneficial factors. Figure A-79 summarizes the beneficial and detrimental metric results for Transmission Utilization.

Figure A-77: Detrimental Factors Causing Divergence between RTC and RTD
2020

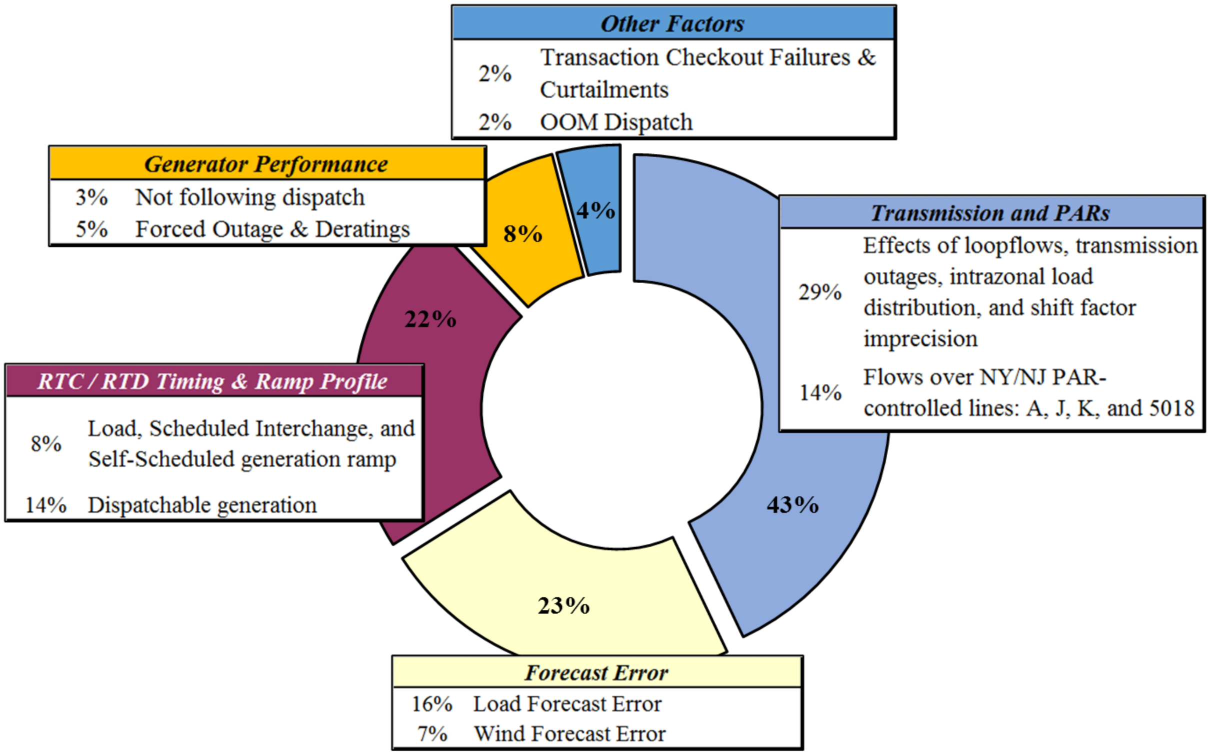
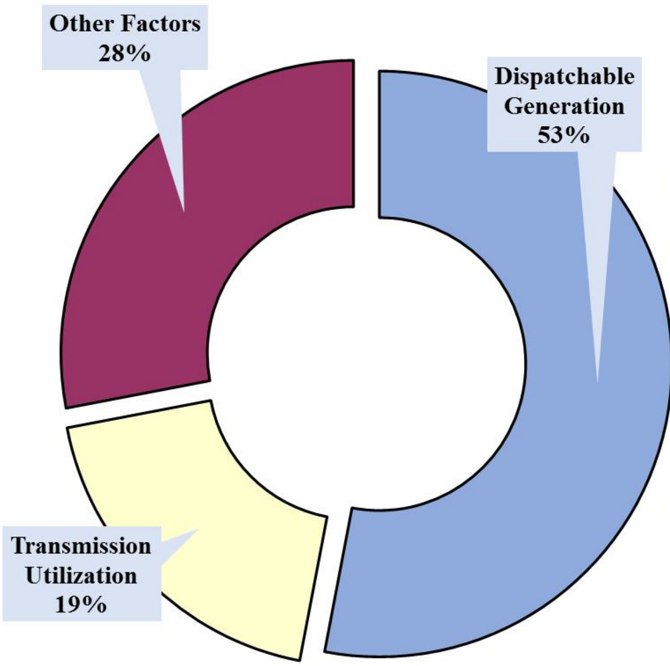
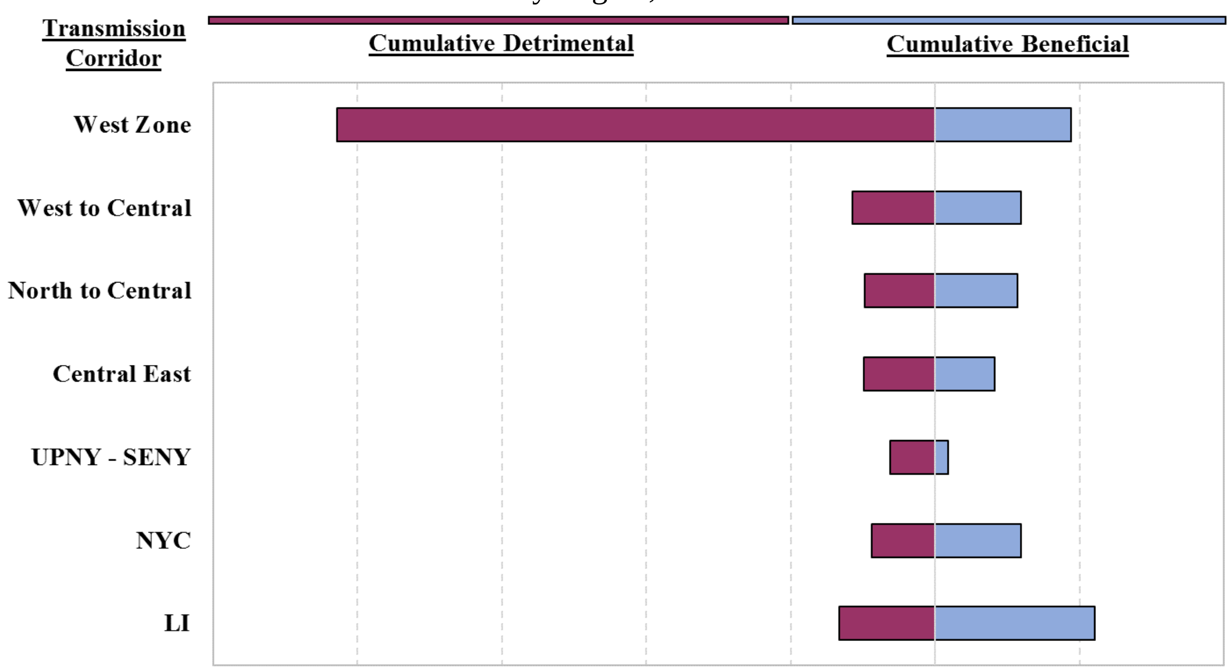


Figure A-78: Beneficial Factors Reducing Divergence between RTC and RTD
2020



"Dispatchable Generation"	
Factors for the redispatch of generators.	
"Other Factors"	
Wind Forecast Error	6%
Ramp Profile	5%
Load Forecast Error	5%
Non-optimized PARs	4%
Not-Following Dispatch	4%
Forced Outage / Derate	3%
OOM Dispatch	1%
Checkout Failures / Curtailment	1%
"Transmission Utilization"	
Includes optimized transmission and PAR operations	

Figure A-79: Effects of Network Modeling on Divergence between RTC and RTD
By Region, 2020



Key Observations: Evaluation of Coordinated Transaction Scheduling

- The evaluations correlating the RTC price forecast error with the magnitude of changes in scheduled interchange (which are shown in Figure A-74 and Figure A-75) suggest that inconsistencies in the ramp assumptions that are used in RTC and RTD (which are illustrated in Figure A-76) 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-74 and Figure A-75). This deters large schedule changes that might otherwise be economic, thereby reducing the efficiency gains from CTS.
- However, it is evident from Figure A-75 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 2020, which were generally similar to those identified for prior years:
  - 43 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.
  - 23 percent from errors in forecasting of load and production from wind turbines.
    - The contribution from the load forecast error rose from prior years, reflecting generally higher load forecast errors in 2020 because of the impact from the Covid-19 pandemic.
  - 10 percent from changes by a market participant or another control area, which are generally outside the NYISO's control, including:
    - 8 percent from generators experiencing a derating, forced outage, or not following dispatch; and
    - 2 percent from transaction checkout failures and curtailments.
  - 22 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-76), 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 2020, similar to prior years as well:
  - 53 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.
    - 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 and Long Island constraints generally exhibited more 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 2020:

- *Efficiency of Fixed-Block Gas Turbine Commitment* – This sub-section evaluates the consistency of real-time pricing with real-time fixed-block 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.

- *Regulation Movement-to-Capacity Ratio* – This sub-section evaluates the actual movement-to-capacity for individual regulation providers versus the single common multiplier used in the regulation scheduling process.

- *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.

- *Market Operations and Prices on High Load Days* – This sub-section evaluates the market effects of SRE commitments for capacity by NYISO and deployment of utility demand response programs by TOs on several high load days.

- *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.

- *Potential Design of Dynamic Reserves for Constrained Areas* – This sub-section describes a modeling approach, in accordance with Recommendation #2015-16, with which locational reserve requirements and associated price signals could be dynamically determined based on load, transmission capability, and online generation.

A. Efficiency of Fixed-Block 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.[326] 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.[327] 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

326 10-minute units can start quickly enough to provide 10-minute non-synchronous reserves.

327 30-minute units can start quickly enough to provide 30-minute non-synchronous reserves, but not quickly enough to provide 10-minute reserves.

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 subsection evaluates the efficiency of real-time commitment and scheduling of fixed-block gas turbines.

Figure A-80: Efficiency of Fixed-Block Gas Turbine Commitment

Figure A-80 measures the efficiency of fixed-block 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-80 shows the average quantity of gas turbine capacity started each day in 2020. 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:

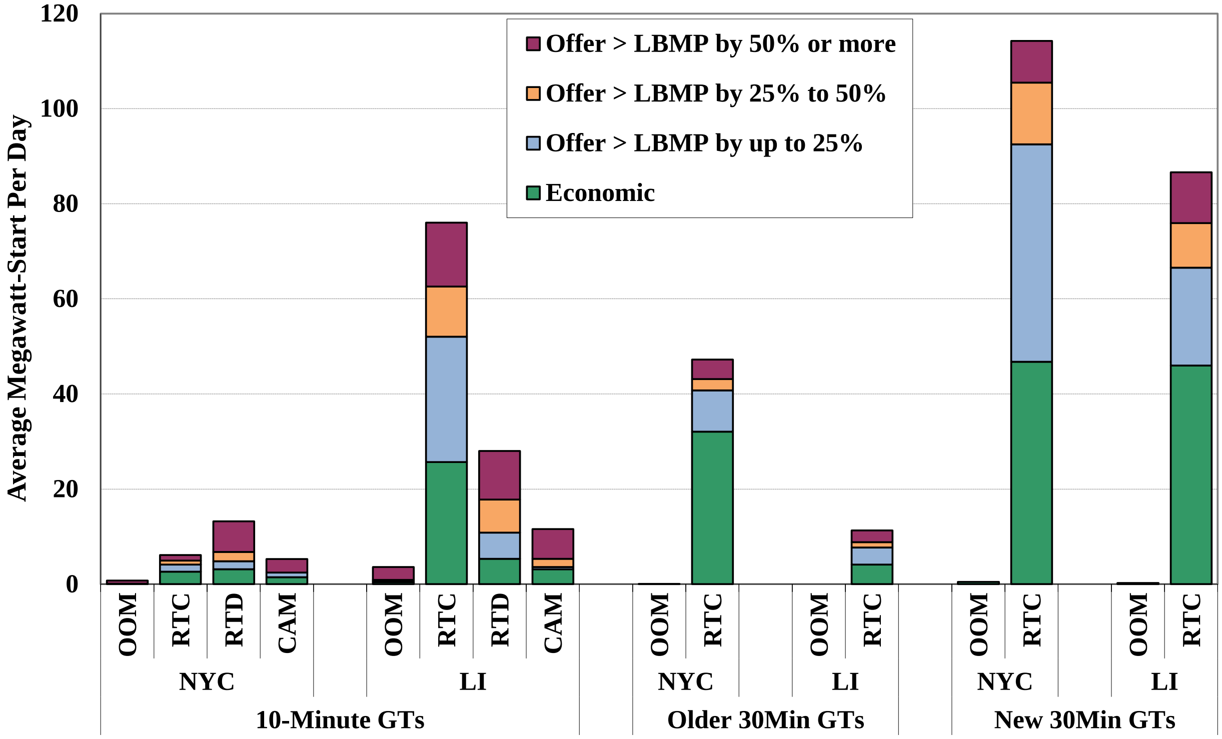
- Offer < LBMP (these commitments were clearly economic);
- Offer > LBMP by up to 25 percent;
- Offer > LBMP by 25 to 50 percent; and
- Offer > LBMP by more than 50 percent.

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,[328] 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.[329] The first pass is a physical dispatch pass, which produces physically feasible base points that are sent to all resources. In this pass, the inflexibility of the fixed-block 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 fixed-block 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-80: Efficiency of Fixed-Block Gas Turbine Commitment
2020



328 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.

329 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.

Table A-6: Combined-Cycle Unit Duct Burner Capacity in New York

Most combined cycle units in New York have a duct burner, which uses supplementary firing to increase the heat energy of a gas turbine's exhaust, making it possible to increase the output of a downstream heat-recovery steam generator. This additional output can be offered into the energy market as a portion of the dispatchable range of the unit. However, most duct-firing capacity is not capable of following a five-minute dispatch signal. The process of starting-up and shutting-down duct burners is similar to the start-up and shut-down of a fast-start unit. For this reason, some combined cycle units with a duct burner do not offer it into the real-time market, while others simply "self-schedule" this capacity in a non-dispatchable way. Table A-6 summarizes the amounts of duct-firing capability in the summer and winter capability periods by load zone.

Table A-6: Combined-Cycle Unit Duct Burner Capacity in New York
By Load Zone

Load Zone	# Generators (PTIDs)	Summer MW	Winter MW
West	4	42	46.5
Genesee	1	9	10
Central	7	38	38.5
North	2	31	31
MHK VL	2	13	15
Capital	10	209	190
HUD VL	5	174	179
NYC	7	149	181
Long Island	4	96	102
NYCA Total	**42**	**761**	**793**

<u>Key Observations: Efficiency of Fixed-Block Gas Turbine Commitment</u>

- Most gas turbine commitments were made by RTC. In 2020, roughly 85 percent was committed by RTC, 14 percent by RTD and RTD-CAM, and 1 percent through OOM instructions.
- Of all gas turbine commitments in 2020, only 42 percent were clearly economic (indicated by green bars in the figure). An additional 29 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 2019.
- Nonetheless, there were many commitments in 2020 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 in the Appendix for analysis of divergence between RTC and RTD).
- In addition, the fast-start price-setting rules did not necessarily reflect the start-up and other commitment costs of the gas turbine in the price-setting logic until the end of 2020.
  - The NYISO implemented the "Enhanced Fast-Start Pricing" project on December 15, 2020, which: (a) extended the existing logic (applied previously only to Fixed Block fast-start units) to all fast-start resources; and (b) included the start-up and minimum generation costs of all fast-start resources in the LBMP calculation. [330]
  - This will likely improve the efficiency of clearing prices for all market participants when fast-start generation resources are being deployed.

- Combined cycle units with a duct burner are able to supply additional generation in the duct-firing range.
  - There are a total of 42 units across the state that are capable of providing 761 MW of duct-firing capacity in the summer and 793 such MW in the winter, collectively.
  - However, most of this duct-firing capacity is not able to follow 5-minute dispatchable signals, making it either unavailable because of no offer in this range or non-dispatchable because of inflexible self-schedule level.
  - The process of starting-up and shutting-down duct burners is similar to the start-up and shut-down of a fast-start peaking unit. Therefore, we recommend NYISO evaluate the potential benefits and costs of developing the capability to commit and de-commit the duct-firing capacity in the real-time market as it would do with an offline peaking unit.[331]
    - The enhanced scheduling capability could significantly increase the availability of operating reserves, which will become more valuable as older peaking units retire over the next four years.

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.

330 See "Enhanced Fast-Start Pricing" by Zachary Stines, MC meeting on November 18, 2020.

331 See Recommendation #2020-1.

Figure A-81 - Figure A-83 & Table A-7: Average GT Performance after a Start-Up Instruction

Figure A-81 to Figure A-83 summarize the performance of offline GTs in responding to start-up instructions that result from economic commitments (including commitment by RTC, RTD, and RTD-CAM) .[332] The figure reports the average performance in 2019 and 2020. The unit's performance is measured based on its output level at its expected full output time (i.e., measured as the GT output at 10 or 30 minutes after receiving a start-up instruction, as a percent of its UOL).[333] Figure A-81 shows the performance evaluation for all GTs while Figure A-82 and Figure A-83 show the same evaluation separately for 10-minute and 30-minute GTs. Since 30-minute GTs cannot be started by either RTD-CAM or RTD, the two categories are excluded in Figure A-83.

For a particular type of start, the x-axis shows the share of starts in each range of performance. The length of the green bar represents the percent of starts in which the unit achieved at least 90 percent of its UOL by the expected full output time. Similarly, the blue, light blue, and orange bars represent the percent of GT starts in the following performance ranges: (a) from 80 to 90 percent; (b) 50 to 80 percent; and (c) 0 to 50 percent, respectively. The burgundy bars show the percent of GT starts that failed to produce any output within the expected start time.

The three figures also compare the performance for each start-up category to the performance of the associated units in the NYISO auditing process. Table A-7 also tabulates this comparison for 2020 with all categories of economic starts combined. The rows in the table provide the number of units in each performance range from 0 to 100 percent with a 10 percent increment. The left hand side of the table shows these numbers based on performance measured during economic starts, while the right hand side of the table shows numbers based on audit results. The units that are in service but were never started by RTC, RTD, or RTD-CAM in 2020 are placed in a separate category of "Not Evaluated", which also includes several units that we could not assess their performance reliably because of data issues. The following is an example read of the table: "23 GTs exhibited a response rate of 80 to 90 percent during economic starts in 2020, 22 of them were audited 38 times in total with seven failures".

332 This evaluation does not include OOM start-ups by either NYISO or TO as we do not have reliable data for the instructed starting times nor self-started units.

333 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 50-to-80-percent group.

Figure A-81: Average GT Performance by Type after a Start-Up Instruction
Economic Starts vs Audit, 2019-2020

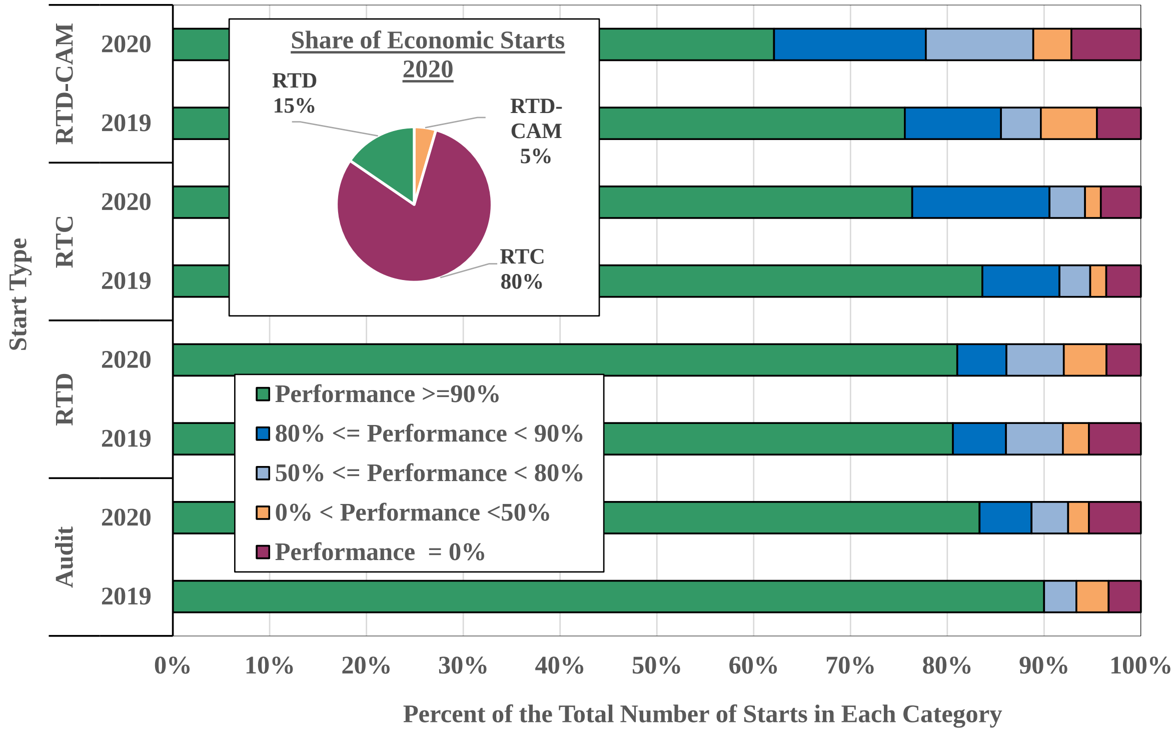


Figure A-82: Average GT Performance by Type after a Start-Up Instruction
Economic Starts vs Audit, for 10-Minute GTs, 2019-2020

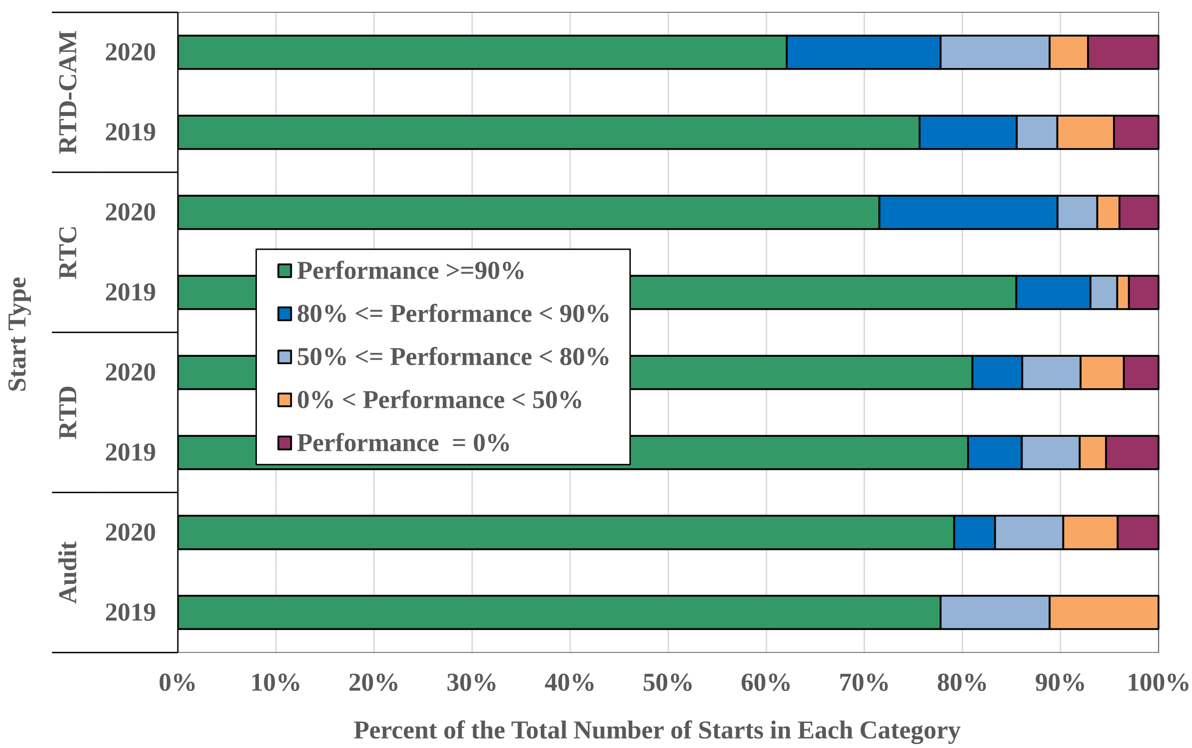


Figure A-83: Average GT Performance by Type after a Start-Up Instruction
Economic Starts vs Audit, for 30-Minute GTs, 2019-2020

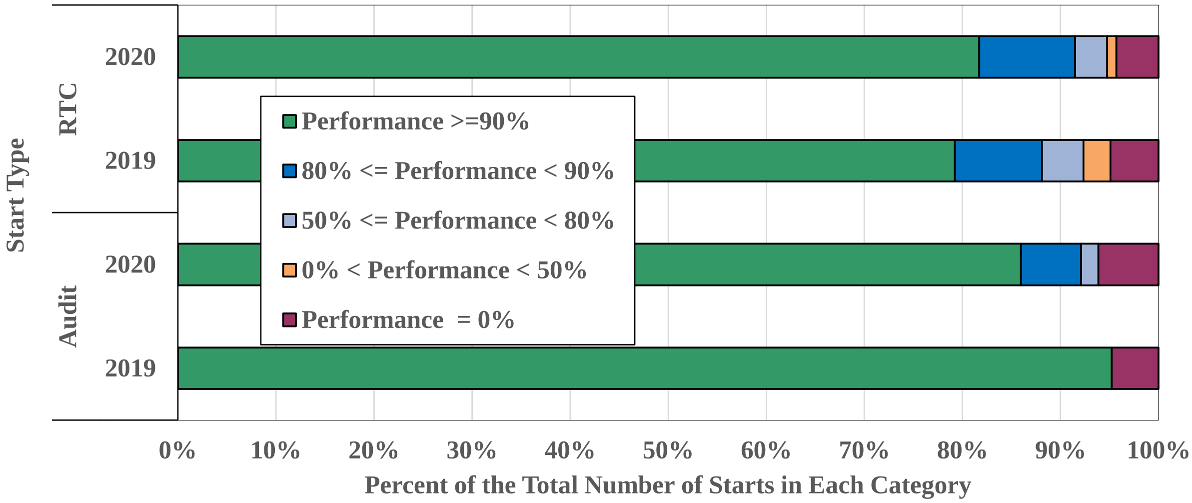


Table A-7: Economic GT Start Performance vs. Audit Results
2020

Economic GT Starts (RTC, RTD, and RTD-CAM)		GT Audit Results		
Performance Category	**No. of Units**	**No. of Audits**	**Unique GTs Audited**	**No. of Audit Failures**
Not Evaluated [1]	27	49	24	7
0% - 10%	1	1	1	0
10% - 20%	0	0	0	0
20% - 30%	1	2	1	1
30% - 40%	2	2	1	0
40% - 50%	1	1	1	0
50% - 60%	4	4	3	1
60% - 70%	6	10	6	2
70% - 80%	7	15	6	4
80% - 90%	23	38	22	7
90% - 100%	73	129	71	1
TOTAL	**145**	**251**	**136**	**23**

Note: 1. Includes 21 units that were never started by RTD, RTC, or RTD-CAM (excluding self-schedules) in 2020 and 6 units that were omitted due to certain data issues for reliable performance assessment.

Figure A-84: Use of Operating Reserves to Manage Congestion in New York City

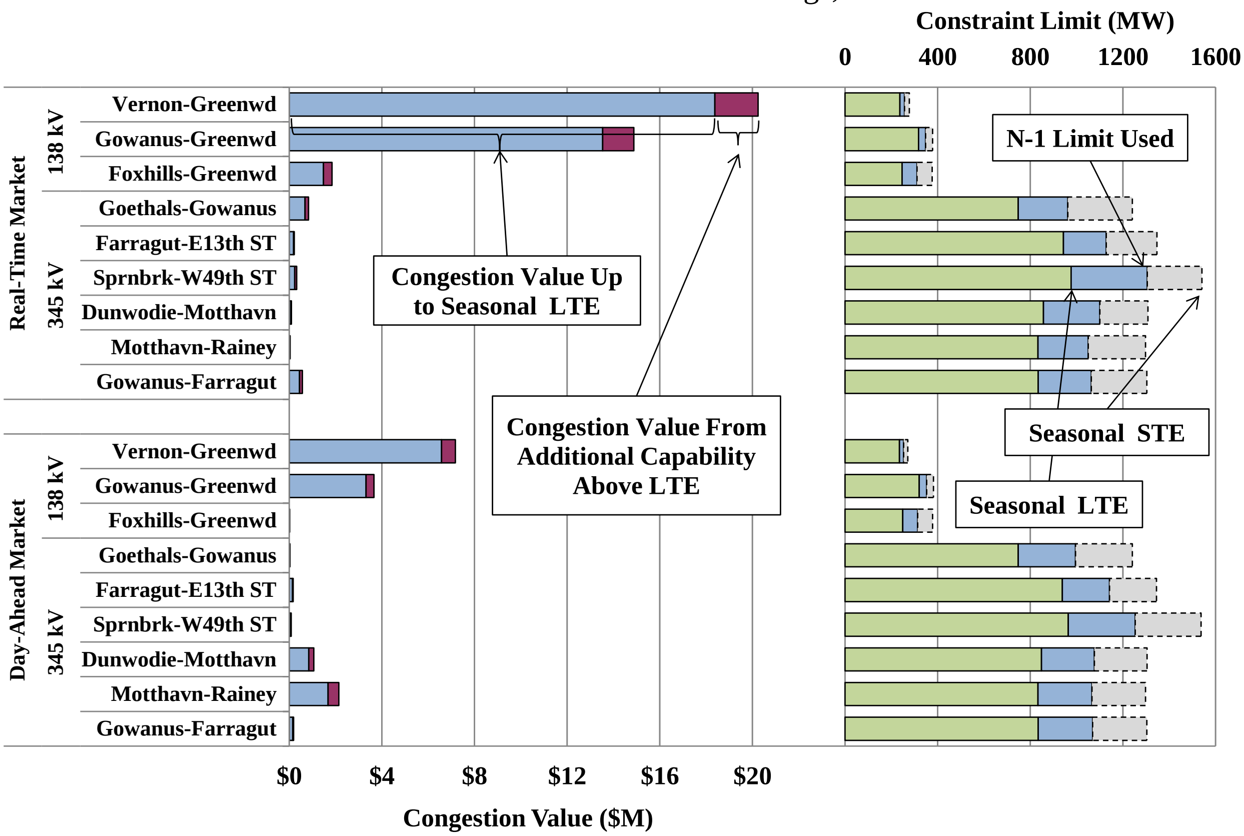
The NYISO sometimes operates a facility above its Long-Term Emergency ("LTE") rating if post-contingency actions (e.g., deployment of operating reserves) would be available to quickly reduce flows to LTE. The use of post-contingency actions is important because it allows the

NYISO to increase flows into load centers and reduce congestion costs. However, the service provided by these actions are not properly compensated.

Figure A-84 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 2020. The blue bars represent the congestion values measured up to the seasonal LTE ratings of the facilities.[334] The red bars represent the congestion values measured for the additional transfer capability above LTE.[335] 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.

Figure A-84: Use of Operating Reserves to Manage N-1 Constraints in New York City

Limits Used vs Seasonal LTE Ratings, 2020



Key Observations: Performance of Operating Reserve Providers

- Among all economic starts, gas turbines exhibited the worst average performance during RTD-CAM starts. In 2020:

334 Congestion value up to seasonal LTE = constraint shadow cost × seasonal LTE rating summed across all market hours / intervals.

335 Congestion value for additional capability above LTE = constraint shadow cost × (modeled constraint limit - seasonal LTE rating) summed across all market hours / intervals.

- Approximately 22 percent of all RTD-CAM starts performed below 80 percent at the evaluation time (i.e., 10-minute mark following the start-up instructions), including 7 percent that failed to start.
  - Although starts by RTD-CAM accounted for just 5 percent of all economic starts, the started GT capacity was typically needed to resolve certain system emergencies, the poor performance can aggravate tight system conditions.
- On the other hand, only 9 to 14 percent of other economic starts performed below 80 percent, generally in line with average audit performance.

- GT start-up performance was generally comparable between 2019 and 2020 except that several 10-minute GTs performed worse in 2020.
  - Some 10-minute GTs performed slightly worse from a low 90 percent performance in 2019 to a high 80 percent performance in 2020.
  - Other 10-minute GTs saw a shift from the higher-performing 80 to 90 percent category in 2019 to the poorer-performing 50 to 80 percent category in 2020. These units may merit more scrutiny to encourage better performance going forward.
- Many GTs performed somewhat better when audited by NYISO than when started by the market model.
  - For example, 90 units had an average performance of 90 percent and above in audits while only 73 units achieved similar performance when responding to start-up instructions from the market model. But when counting performance of 80 percent and above, 93 units achieved this in audits, very comparable to the 96 units in the market model starts.
  - On the other end of the spectrum, a small number of units (five) performed poorly during their audit, but performed at a high level during the year showing that even the best performers may have an anomalous poor start.
- The NYISO routinely audits 10- and 30-minute non-synchronous reserve providers to ensure that they are capable of providing these reserve services.
  - Recent NYISO procedural enhancements aim to audit each GT either (a) once per Capability Period or (b) at least once per Capability Year.
  - We reviewed NYISO audit results and found that the frequency of GT audits has increased markedly in 2020.
    - There have been 251 audits (on 136 unique GTs), much higher than in prior years, which saw an average of 49 GT audits performed annually from 2016 to 2019.
    - Units with relatively poor performance and/or infrequent market-based commitment have been audited much more frequently under these new procedures.

- Further enhancements to this audit process could be beneficial such as:
  - Using performance during reserve pick-ups or economic starts in lieu of audits would reduce out-of-market actions and uplift costs. Furthermore, since audits enable a resource to remain qualified to sell operating reserves, they may be considered a cost of participation rather than a cost that should be borne by customers through uplift. This is similar to the practice of requiring individual resource owners to bear the costs of DMNC testing, since it enables them to qualify to sell capacity.
  - Since units that perform well during audits may still perform poorly during normal market operations, it may be necessary to suspend or disqualify poor performers.
    - We found 7 GTs that performed at nearly 100 percent during the audit but below 70 percent in economic starts.
    - 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.[336]
- 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 2020, nearly 70 percent (or $40 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) 20 to 60 MW for the 138 kV constraints; and (b) 180 to 330 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.

336 See "More Granular Operating Reserves: Reserve Provider Performance", by Ashley Ferrer at April 7, 2020 MIWG meeting.

- We have recommended that the NYISO efficiently schedule and compensate operating reserve units that can help satisfy transmission security criteria.[337]

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.[338] 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.[339]

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.[340]

Figure A-85: 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 2020.

Figure A-85 evaluates operations of these NY-NJ PARs under M2M with PJM in 2020 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;

337 See Recommendation #2016-1.

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

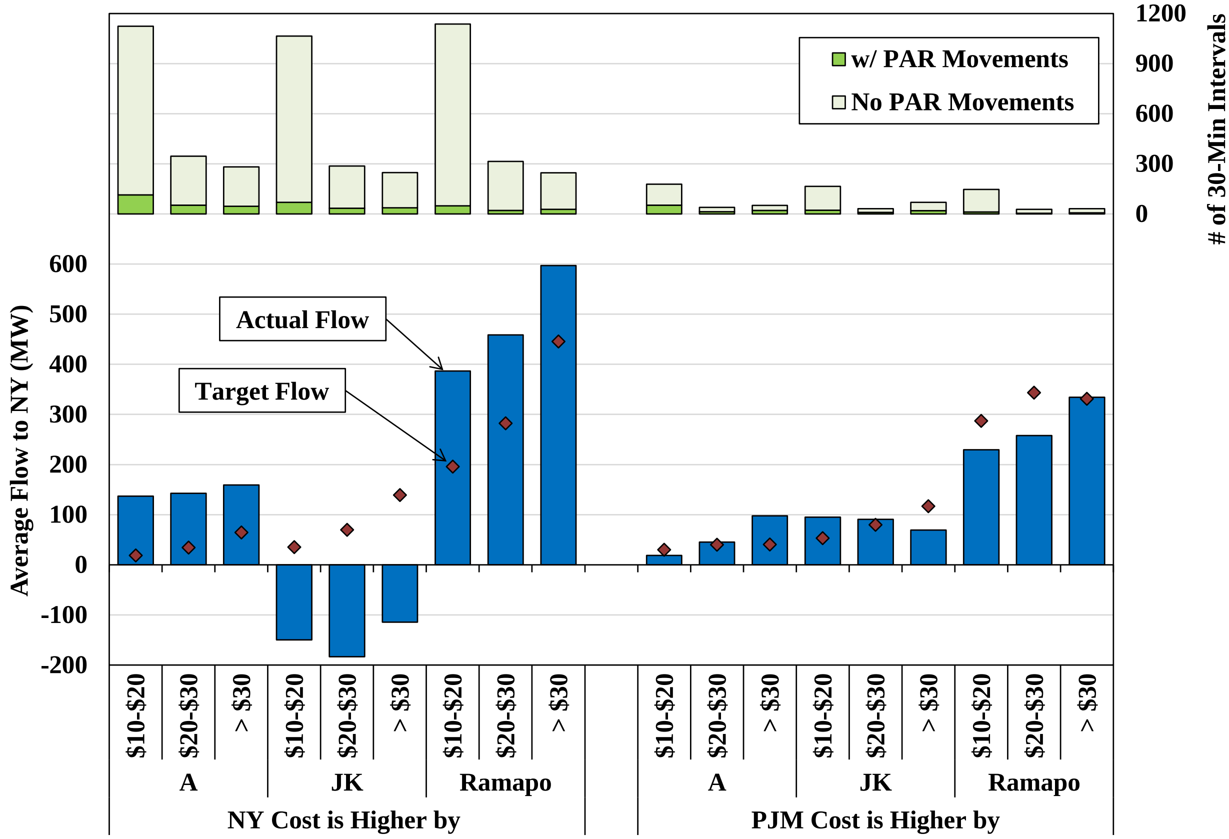
339 These include two Ramapo PARs that control the 5018 line, three Waldwick PARs that control the J and K lines, and one PAR that controls the A line.

340 The list of pre-defined flowgates is posted here 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-85: NY-NJ PAR Operation under M2M with PJM
2020



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 as more flows are brought into New York to relieve congestion on the interface. However, these additional flows tend to aggravate congestion on the constraints in the West Zone, leading to balancing congestion shortfalls.

- The 115 kV constraints in the West Zone were not incorporated in the M2M PAR Coordination until December 2019, before which the net effect of this PAR operation was often inefficient, leading to net balancing congestion shortfalls.
- For example, we estimated that the M2M PARs resulted in a total of nearly $5 million of net shortfalls on the Central-East interface and West Zone constraints in 2019.
- However, this improved to a total of $0.6 million of net surpluses in 2020 following the inclusion of 115 kV West Zone constraints in the M2M JOA. (see Section III in the Appendix).

- Despite the improvement, there were still instances when PAR adjustments may have been available and would have reduced overall congestion but either no adjustments were made or the adjustments were insufficient.
  - During all the 30-minute periods of 2020 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 11 percent of these periods.
    - 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 14 percent of overall price divergence in 2020.
  - 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.[341] 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-86: 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 2020.

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 2020. The evaluation is done for the following eleven PAR-controlled lines:

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341 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.[342]

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.[343] For Ontario, the analysis assumes a day-ahead schedule of 0 MW since Ontario does not operate a day-ahead

342 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.

343 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
2020

	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					-9	$3.44	52%	$1
New England to NYCA								
Sand Bar	-72	-$9.48	95%	$5	-2	-$9.30	55%	$0.4
PJM to NYCA								
Waldwick	41	$1.57	70%	$1	-23	$0.83	39%	-$3
Ramapo	247	$2.26	75%	$7	88	$1.87	61%	$4
Goethals	21	$2.63	74%	$1	91	$1.89	53%	$0.7
Long Island to NYC								
Lake Success	141	-$5.53	2%	-$7	-3	-$5.93	54%	$0.1
Valley Stream	83	-$7.66	2%	-$6	0	-$7.10	53%	-$0.1

Figure A-86: Efficiency of Scheduling on PAR Controlled Lines
Lake Success-Jamaica Line – 2020

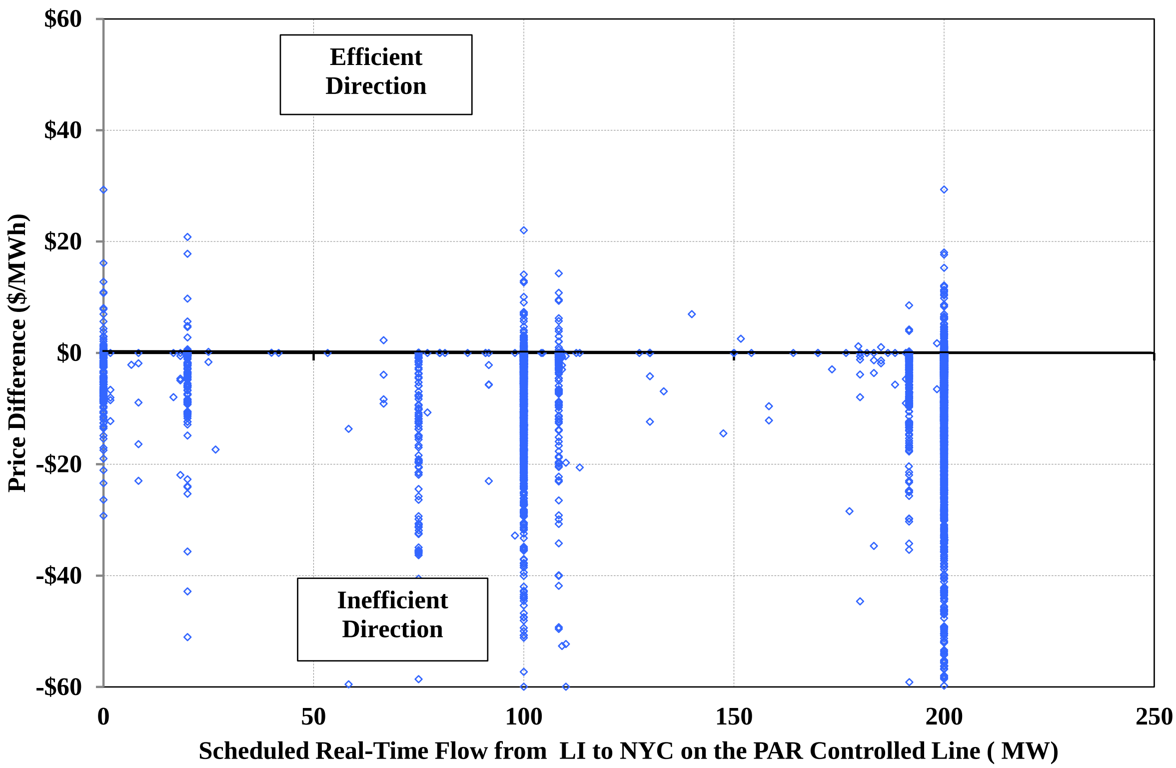

Figure A-86 provides additional detail on the efficiency of scheduling for one of the lines in the table. The figure is a scatter plot of power flows versus price differences across the Lake

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 2020,
    - Scheduled power across the 901 and 903 lines flowed in the efficient direction in only 2 percent of hours in the day-ahead market. [344]
    - As a result, the use of the two lines increased day-ahead production costs by an estimated $13 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.

344 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-85). Consequently, in 2020,
    - The 5018 line accounted for a $11 million net reduction in production costs;
    - The A line accounted for a $2 million net reduction in production costs; while
    - The J and K lines accounted for a $2 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).[345]

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 2020. 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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[345] The proposed financial right is described in Section III.I 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 2020 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).[346,347] RTD and RTC assume the flow over these lines will remain fixed in future intervals,[348] 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.

346 These lines are discussed further in Subsection D.

347 M2M coordination is discussed further in Subsection C.

348 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
2020

	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**		**309**		**2052**		**705**		**299**		**358**		**262**		**283**	
Number of Price Spikes	**184**		**2560**		**90**		**166**		**792**		**231**		**1302**		**219**	
Average Constraint Shadow Price	**$194**		**$480**		**$455**		**$370**		**$374**		**$437**		**$461**		**$521**	
Source of Increased Constraint Cost:	**(MW)**	**(%)**	**(MW)**	**(%)**	**(MW)**	**(%)**	**(MW)**	**(%)**	**(MW)**	**(%)**	**(MW)**	**(%)**	**(MW)**	**(%)**	**(MW)**	**(%)**
Scheduled By RTC	**170**	**64%**	**1**	**17%**	**73**	**49%**	**29**	**47%**	**7**	**50%**	**7**	**28%**	**2**	**33%**	**1**	**20%**
External Interchange	89	34%	1	17%	29	19%	13	21%	2	14%	4	16%	0	0%	1	20%
RTC Shutdown Resource	62	23%	0	0%	24	16%	14	23%	4	29%	2	8%	2	33%	0	0%
Self Scheduled Shutdown/Dispatch	19	7%	0	0%	20	13%	2	3%	1	7%	1	4%	0	0%	0	0%
Flow Change from Non-Modeled Factors	**4**	**2%**	**5**	**83%**	**61**	**41%**	**20**	**32%**	**6**	**43%**	**16**	**64%**	**4**	**67%**	**2**	**40%**
Loop Flows & Other Non-Market	2	1%	4	67%	22	15%	11	18%	5	36%	8	32%	3	50%	1	20%
Fixed Schedule PARs	0	0%	1	17%	35	23%	9	15%	0	0%	8	32%	1	17%	1	20%
Redispatch for Other Constraint (OOM)	2	1%	0	0%	4	3%	0	0%	1	7%	0	0%	0	0%	0	0%
Other Factors	**90**	**34%**	**0**	**0%**	**15**	**10%**	**13**	**21%**	**1**	**7%**	**2**	**8%**	**0**	**0%**	**2**	**40%**
Load	55	21%	0	0%	12	8%	7	11%	1	7%	2	8%	0	0%	1	20%
Generator Trip/Derate/Dragging	19	7%	0	0%	2	1%	6	10%	0	0%	0	0%	0	0%	0	0%
Wind	16	6%	0	0%	1	1%	0	0%	0	0%	0	0%	0	0%	1	20%
Total	**264**		**6**		**149**		**62**		**14**		**25**		**6**		**5**	
Redispatch for Other Constraint (RTD)	**89**		**0**		**17**		**2**		**1**		**2**		**7**		**6**	

Key Observations: Transient Real-Time Price Volatility

- Transient shadow price spikes (as defined in this report) occurred in roughly 4 percent of all intervals in 2020, less frequently than in 2019 partly because of lower load levels and improvements in congestion management in the West Zone.

   - Most of these transient spikes occurred on constraints in the West Zone (44 percent) and in the New York City load pockets (22 percent).
   - 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. Load variation became more impactful in 2020 as a result of larger load forecast errors because of the COVID-19 pandemic.
   - For the West Zone Lines, the primary driver continued to be 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. However, the frequency of transient price spikes in the West Zone fell 63 percent from 2019 largely because of improvements in the M2M process (see subsection C) and the use of more conservative assumptions regarding loop flows.
   - 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 drivers included external interchange adjustment, generator shutdowns by RTC, and loop flows and other non-market scheduled factors. The latter two were also the primary drivers for other constraints inside Long Island.
   - 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 loop flows and other non-market factors that affect the constraint transfer capability and generator shutdowns by RTC.
   - For North to Central constraints, the primary drivers included loop flows and other non-market factors that affect the constraint transfer capability, variations in wind output and the load forecast, and fluctuations in fixed-schedule PAR flows (i.e., the L34P line) .

- 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, New York City, 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: [349]
  - 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:

[349] 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 found that it would be beneficial to adjust the assumed level of LEC in RTC in the clockwise direction under most conditions.[350]
    - Because of the current software limitation, the NYISO cannot implement variable adjustments for different levels of LEC although this is desirable.
    - The NYISO began in November 2019 to limit the assumed LEC in RTC to be the greater of 100 MW in the clockwise direction or the most recent telemetered value. This has been an improvement over the previous assumption.
    - 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.[351]

F. Regulation Movement-to-Capacity Ratio

Regulation providers submit a two-part offer in the regulation market that indicates two separate costs of providing regulation services. One is the capacity offer that indicates the cost associated with setting aside capacity for regulation. The other is the movement offer that indicates additional cost associated with moving the resource up and down every six seconds when deployed to provide regulation. Under the current market rules, a composite offer is calculated equal to (*capacity offer*) plus (*movement offer*) times (*movement multiplier*) for each regulation provider that estimates its overall cost of providing regulation and is used in the market software for scheduling and pricing.

Resources are currently scheduled assuming a common Movement Multiplier of 13 per MW of capability, but they are deployed based on individual ramping capability and are compensated according to actual movement. This inconsistency between assumed costs and actual costs

350 See the analysis in Section V.E of the Appendix in our 2019 State of the Market Report.

351 See Recommendation #2014-9.

incurred can lead to inefficiency in the resource scheduling and pricing. This subsection focuses on examining actual regulation movement versus assumed common multiplier.

Figure A-87 & Figure A-88: Regulation Movement-to-Capacity Ratio

Figure A-87 shows a distribution of actual movement-to-capacity ratio of all scheduled regulation suppliers from one sample day. The blue bars show the average scheduled regulation capacity in each movement-to-capacity ratio. The solid blue line represents the capacity weighted average actual movement-to-capacity ratio for the day, compared to the multiplier of 13 that is used for all resources when formulating the composite regulation offer.

Figure A-88 tracks the variation of regulation movement-to-capacity ratio in recent years, summarizing the following quantities by month:

- Average regulation requirement – The regulation requirement varies by hour by season. This is the hourly average regulation requirement for each month.

- Average actual regulation movement-to-capacity ratio – This is calculated as total regulation movement MW from all resources divided by total scheduled regulation capacity in each month.

Figure A-87: Distribution of Actual Regulation Movement-to-Capacity Ratio
From a Sample Day

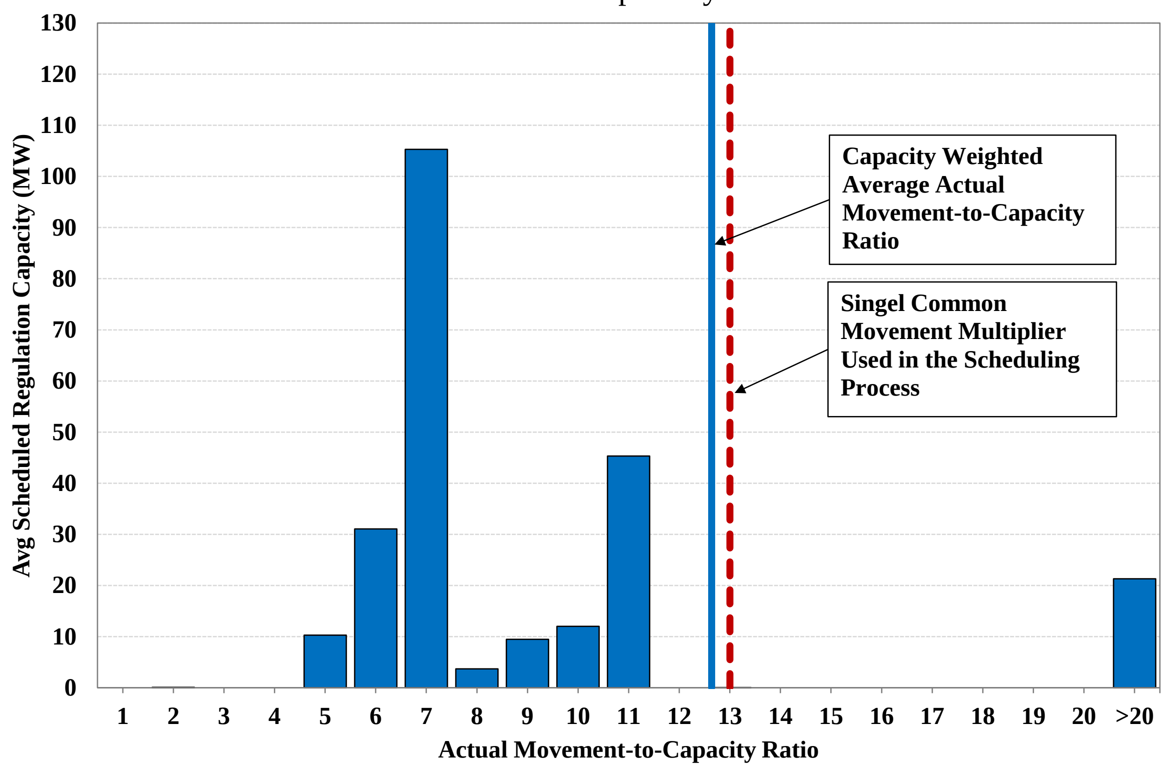
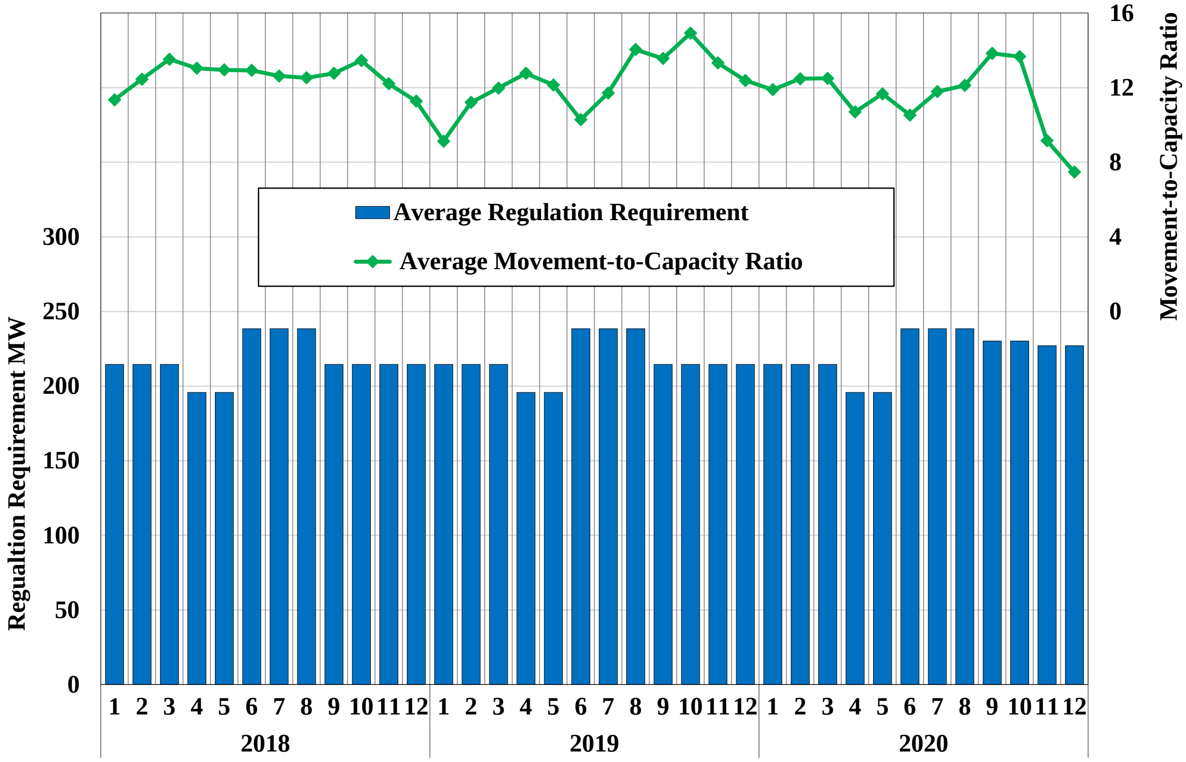


Figure A-88: Regulation Requirement and Movement-to-Capacity Ratio
By Month, 2018-2020



Key Observations: Regulation Movement-to-Capacity Ratio

- Regulation resources are scheduled assuming a common movement multiplier of 13 per MW of capability, but they are deployed based on individual ramping capability and are compensated according to instructed movement.
  - Although the long-term average movement-to-capacity ratio of all regulation suppliers combined is close to the assumed common multiplier of 13, wide variations exist not only among individual resources but also from month to month.
  - The NYISO increased the deadband setting for regulation deployment in November 2020, resulting in less regulation movement and much smaller average movement-to-capacity ratios in November and December. The NYISO is looking to revise the common multiplier to a more appropriate level.
- Using a common multiplier for all units can significantly underestimate the cost of fast-ramping resources in the scheduling process.
  - This led to uplift for some fast-ramping resources. For example, a battery storage resource received nearly $250,000 of uplift payments for this reason during the period from July to December 2020.

- This gives some fast-ramping resources incentives to raise their movement offer prices above marginal cost, which is not efficient. This concern could become more significant as the number of fast-ramping resources increases.

G. 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.

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 2020: [352]

- Shortages of operating reserves and regulation (evaluated in this Subsection); and
- Transmission shortages (evaluated in Subsection H).

Figure A-89: 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.

352 Our prior reports also evaluated market operations during reliability demand response deployments. In 2020, the NYISO did not deploy reliability demand response resources, so the effect of the scarcity pricing is not evaluated in this report.

Figure A-89 summarizes physical ancillary services shortages and their effects on real-time prices in 2019 and 2020 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.

- 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.

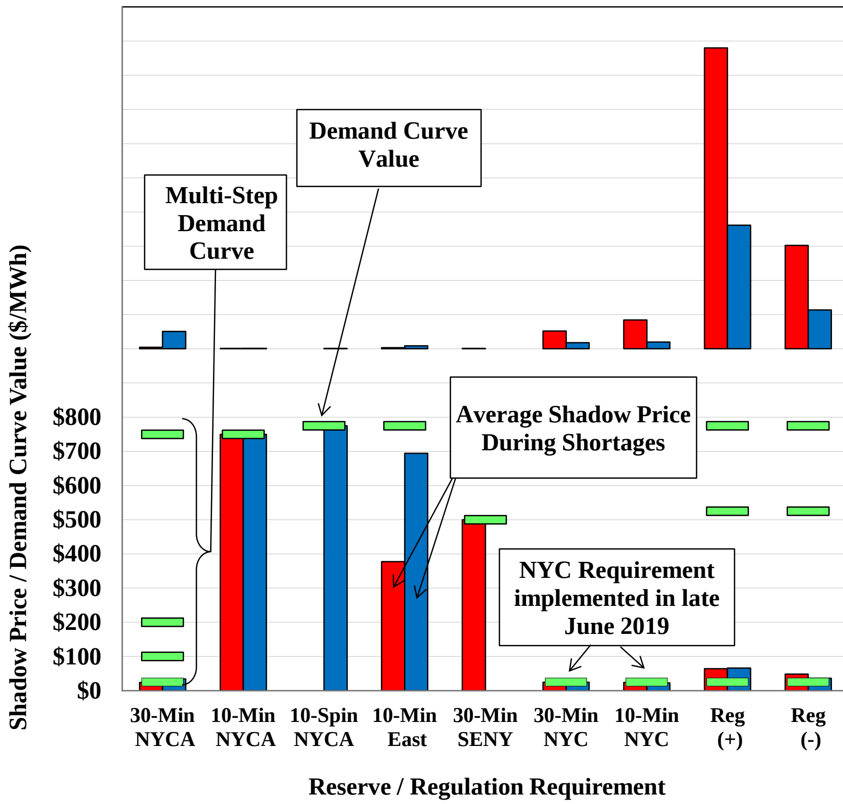
The top portion of the figure shows the frequency of physical shortages. The bottom portion shows the average shadow price during physical shortage intervals and the current demand curve level of the requirement. The table shows the average shadow prices during physical shortages multiplied by the frequency 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-89: Real-Time Prices During Ancillary Services Shortages
2019 – 2020



Average Contribution to Energy Price		2019	2020
Requirement:			
	30-Min NYCA	$0.00	$0.07
	10-Min NYCA	$0.01	$0.04
	10-Spin NYCA	$0.00	$0.01
	10-Min East	$0.05	$0.24
	30-Min SENY	$0.01	$0.00
	30-Min NYC	$0.05	$0.02
	10-Min NYC	$0.08	$0.02
	Reg (+)	$1.48	$0.64
	Reg (-)	-$0.33	-$0.07
Affected Region:			
	West NY	$1.17	$0.68
	East NY (w/o NYC)	$1.24	$0.92
	NYC	$1.36	$0.95

Figure A-90 & Table A-10: Reserves Shortages in New York City

The NYISO currently models two reserves requirements in NYC: [353]

- 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 2020 (excluding months without shortages). 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.

[353] The NYISO started to model these two requirements on June 26, 2019.

- 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 reduced 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
2020

	RT Reserve Shortages in NYC in 2020					
Month	w/ TSA			w/o TSA		
	# Intervals	Avg. Shortage MW	#Intervals w/ toNYC Congestion	# Intervals	Avg. Shortage MW	#Intervals w/ toNYC Congestion
Feb				7	215	0
May				2	13	0
Jun				2	63	0
Jul	28	43	0	2	3	0
Aug	76	134	7	35	140	31
Nov				14	73	0
Dec				7	16	0
Total	**104**	**109**	**7**	**69**	**112**	**31**

Figure A-90 illustrates a sample real-time shortage event that coincided with a TSA event on August 25, 2020. The TSA event occurred from 17:00 to 20:00, while New York City was short of reserves (either 10-minute or 30-minute or both) from 17:00 to 18:40. For each interval from the beginning of hour 16 to the end of hour 20, the figure shows:

- The amount of reserve shortages (red bar); and

- Net imports from upstate areas (blue bar).[354]

When net imports to New York City drop significantly because New York City generators increase output, it creates a reserve import capability that can be used during a contingency.

354 This is calculated as (NYC load) minus (NYC gen) minus (HTP imports) minus (VFT imports) minus (flows on the 901/903 lines into NYC) minus (flows on the A line into NYC).

Therefore, when reserve import capability is available into the city, less reserve capacity needs to be held on generators in New York City to maintain reliability.

Figure A-90: Real-Time Reserve Shortages in New York City
Sample Event on August 25, 2020

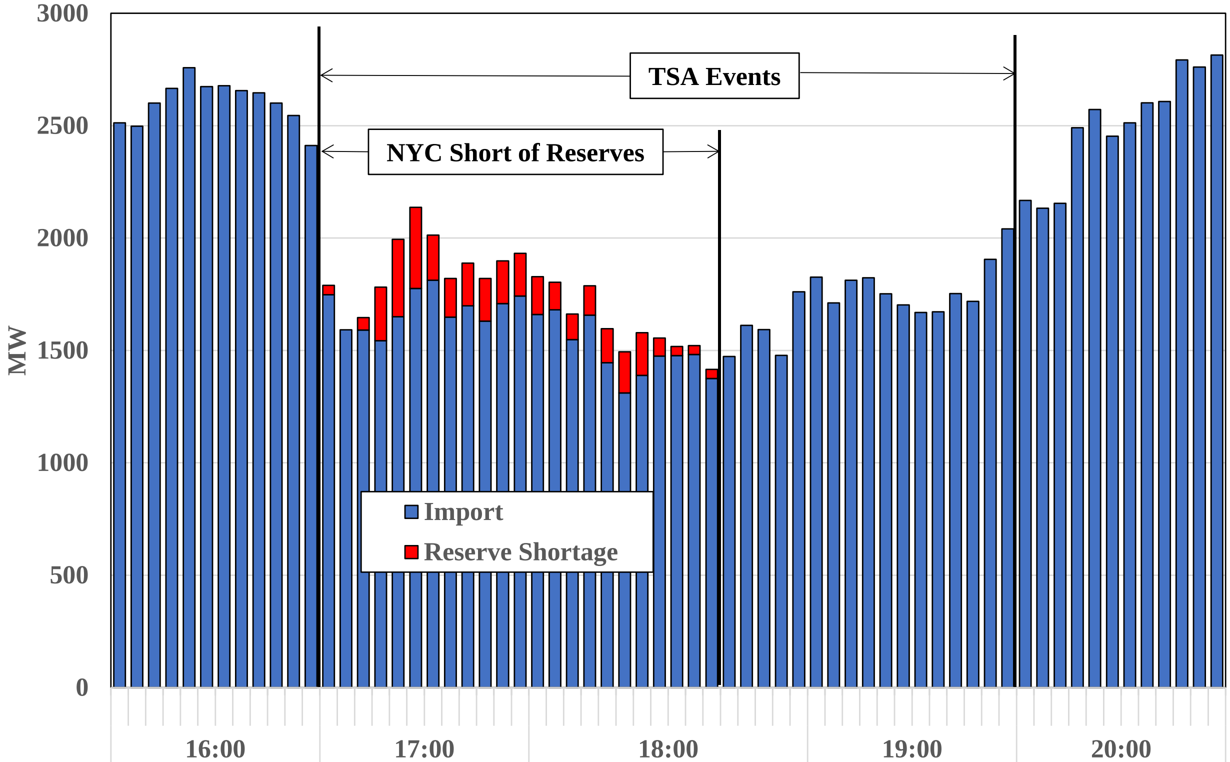


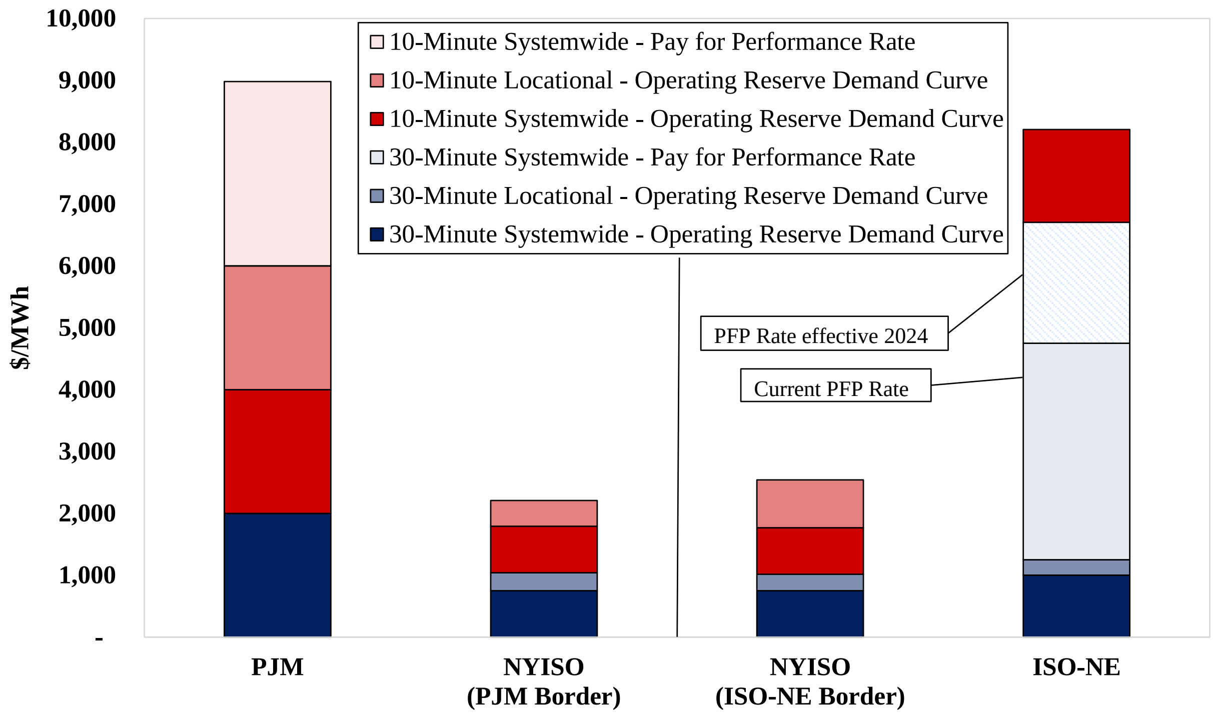
Figure A-91: Comparison of Shortage Pricing in NYISO and Neighboring Markets

In recent years, shortage pricing values in the neighboring PJM and ISO-NE regions have increased dramatically relative to NYISO. ISO-NE implemented Pay-for-Performance in its capacity market in 2018, which provides real-time performance incentives of $3,500/MWh, rising to $5,455/MWh in 2024. PJM Capacity Performance rules provide real-time performance incentives of approximately $3,000/MWh, and PJM also adopted significant increases to its operating reserve demand curves in 2020 that would increase 30-minute, 10-minute and local reserve price adders to $2,000/MWh each beginning in 2022.

These stronger incentives should provide incentives for generators to invest in making their units more reliable and available during tight operating conditions. However, when there is an imbalance between the market incentives provided in two adjacent regions, it can lead market participants to schedule interchange from the area with weaker incentives to the area with stronger incentives even when the area with weaker incentives is in a less-reliable state. In some cases, this could lead the operators of the control area with weaker incentives to maintain reliability through out-of-market actions (e.g., purchases of emergency energy). This may be necessary to maintain reliability in the short-term, but it tends to undermine incentives for investment in the long-term.

Figure A-91 compares incentives for NYISO resources during real-time shortage events to those in neighboring markets. These include maximum 30-minute and 10-minute Non-Spin operating reserve demand curve values as well as Pay-for-Performance penalty rates. A resource may face a total incentive that is the sum of each of these sources when multiple reserve product shortages and/or pay-for-performance scarcity conditions are in effect simultaneously. Values shown for NYISO reflect the revised operating reserve demand curves filed by NYISO with FERC in 2021, which would increase some shadow prices relative to current levels. NYISO 'locational' prices are shown for the regions at the border of each neighboring ISO to indicate the comparative incentives faced by NYISO suppliers when shortage pricing in the neighboring area is in effect.[355]

Figure A-91: Shortage Pricing in NYISO vs. Neighboring Markets



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 1.8 percent of intervals in 2020, down from 4.5 percent in 2019. The reduction was attributable to:

355 Locational prices for PJM refers to the Mid-Atlantic Dominion subzone, which includes several areas in New Jersey and Pennsylvania that border NYISO. Locational prices for ISO-NE refer to Connecticut. Locational prices for NYISO (PJM Border) assign 54 percent weight to the East 30-minute, SENY 30-minute, and East 10-minute shadow prices. Locational prices for NYISO (ISO-NE Border) include the full value of East 30-minute and East 10-minute shadow prices and assign 45 percent weight to the SENY 30-minute shadow price.

  - 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.
  - However, atypical maintenance schedules with more outages occurring in the last quarter of 2020, along with tight fuel supply conditions in December because of cold weather, contributed to a 10 percent increase in shortage intervals in that time period compared to 2019.
- All other ancillary services shortages occurred very infrequently in 2020.

- New York City had real-time reserve shortages in 173 intervals in 2020.
  - Roughly 60 percent of these intervals coincided with TSA events, during which transmission constraints from upstate into New York City were rarely binding. As illustrated in Figure A-90, unutilized import capability during shortage intervals often exceeded the shortage quantity.
  - In the remaining 40 percent of the shortage intervals that did not have TSA events, transmission constraints from upstate to New York City were binding in 45 percent of these intervals. The shortages were moderate in most of these intervals, averaging only 112 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.[356]
  - 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.
  - The incentives provided by ISO-NE during reserve shortages – The combination of reserve demand curve shadow prices and pay-for-performance penalty rates can provide incentives of up to $4,750/MWh when there is a shortage of 30-minute

356 See Recommendation #2015-16.

reserves (rising to $6,705 in 2024) compared to $1,015/MWh in NYISO at the ISO-NE border.

- The incentives provided by PJM during reserve shortages – Beginning in 2022, the combination of reserve demand curve shadow prices and pay-for-performance penalty rates in PJM will provide incentives of up to $9,000/MWh during a shortage of both 10-minute and 30-minute reserves, compared to $2,210/MWh in NYISO at the PJM border.
- The value of lost load (VOLL) to consumers in NYISO during very deep reserve shortages – The NYISO has estimated how the likelihood of load shedding increases as the available operating reserves drop far below required levels.[357] This suggests that the maximum NYISO reserve demand curves are well below the value of incentivizing performance during situations when the probability of loss of load is high (such as during a deep shortage of multiple reserve products).
- Therefore, the market incentives to import power into New York under tight conditions are not sufficient.[358]
  - We have recommended that the NYISO consider increasing the operating reserve demand curves to: (a) ensure reliability after PJM and ISO-NE fully 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.[359]
  - In 2021, the NYISO filed tariff changes with FERC that would partially address this recommendation.[360] The proposed changes would increase the quantity of NYCA 30-minute reserves that are assigned the current maximum shadow price of $750/MWh and add demand curve steps that reflect the historical costs of operator actions taken to maintain reliability. These changes would improve the efficiency of the reserve demand curves by reducing the need for out-of-market actions during reserve shortages. However, the proposed changes do not alter the NYCA systemwide maximum prices that occur during reserve shortages or emergencies. The NYISO should continue to evaluate higher shortage pricing values, including higher maximum values during systemwide scarcity.

357 See the presentation "Ancillary Services Shortage Pricing – Data Analysis" by Pallavi Jain, at the MIWG meeting on October, 18, 2019.

358 See the analysis in Section V.F of the Appendix of our *2018 State of the Market Report* for details of the September 3, 2018 event when operators engaged in out-of-market actions to maintain NYISO reliability.

359 See Recommendation #2017-2.

360 See FERC docket ER21-1018.

H. 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, [361] 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").[362]

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.

This subsection evaluates market performance during transmission shortages in 2020, 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.[363] In such cases,

361 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.

362 These changes are discussed in detail in Commission Docket ER17-1453-000.

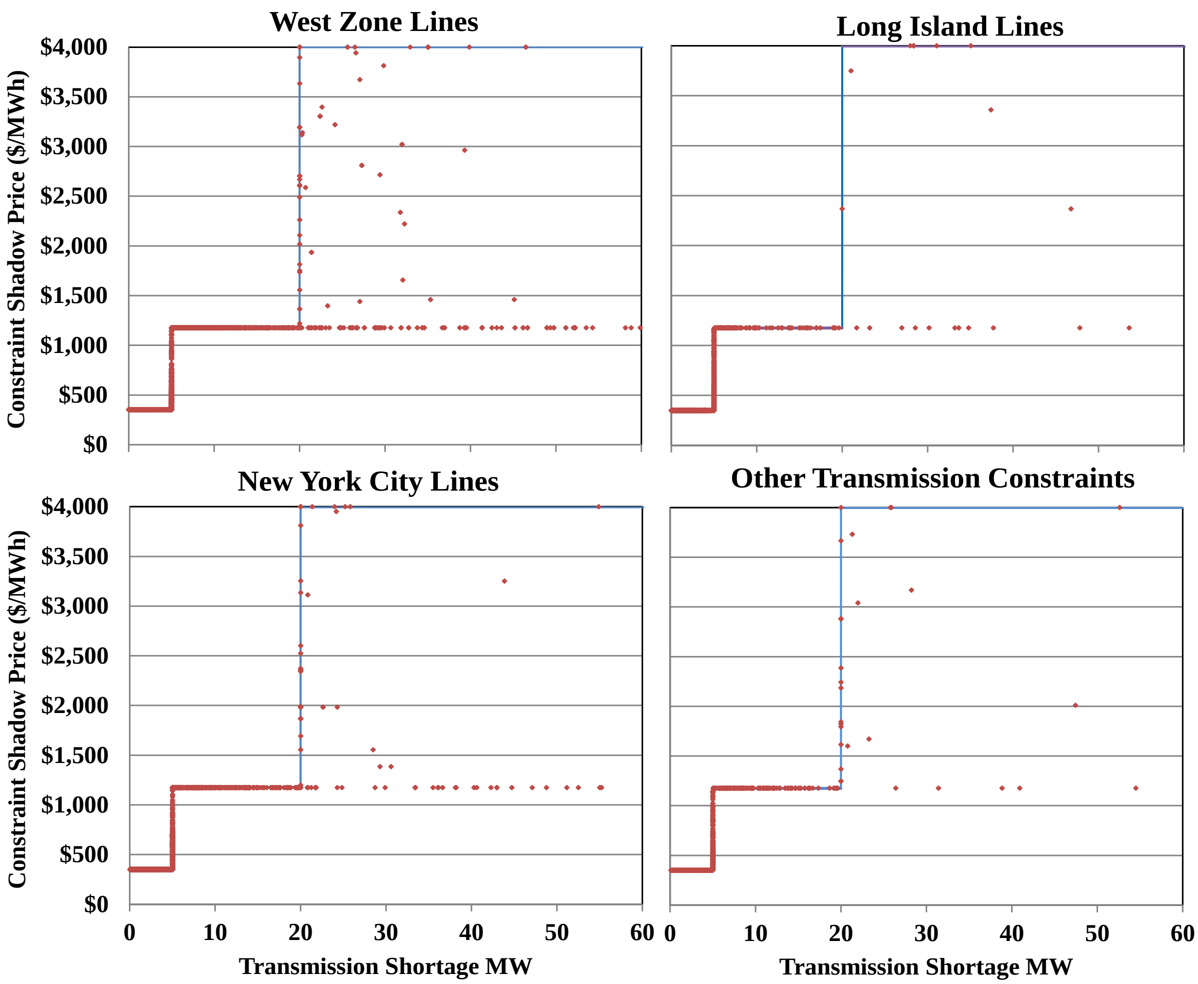
363 Offline quick-start gas turbine is usually the most expensive available capacity due to their commitment costs, so offline gas turbines are usually not counted towards resolving the constraint unless all available online generation has already been scheduled. If a gas turbine is scheduled by RTD 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.

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.[364] This category of shortage is evaluated in this section as well.

Figure A-92, Table A-11 & Figure A-93: Real-Time Congestion Management with GTDC

Figure A-92 examines the use of the GTDC during transmission shortages in the real-time market by constraint group in 2020.

Figure A-92: Real-Time Transmission Shortages with the GTDC
By Transmission Group, 2020



364 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.

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)[365] showing on the x-axis and the constraint shadow price on the y-axis.

Table A-11 evaluates the congestion-relief effect from offline GTs and the effect of CRM on different transmission constraints in 2020. The table summarizes the following quantities for the transmission constraints grouped by facility voltage class and by location:

- The number of constraint-shortage intervals – This indicates the total number of constraint-shortage intervals in each facility group, 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.
- Average shortage quantity – This includes: (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.
- Average constraint limit – This indicates the average transmission limit overall all transmission constraints in each facility group.
- Average CRM – This indicates the average CRM MW used in each facility group.
- CRM as a percent of limit – This is 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.

365 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.

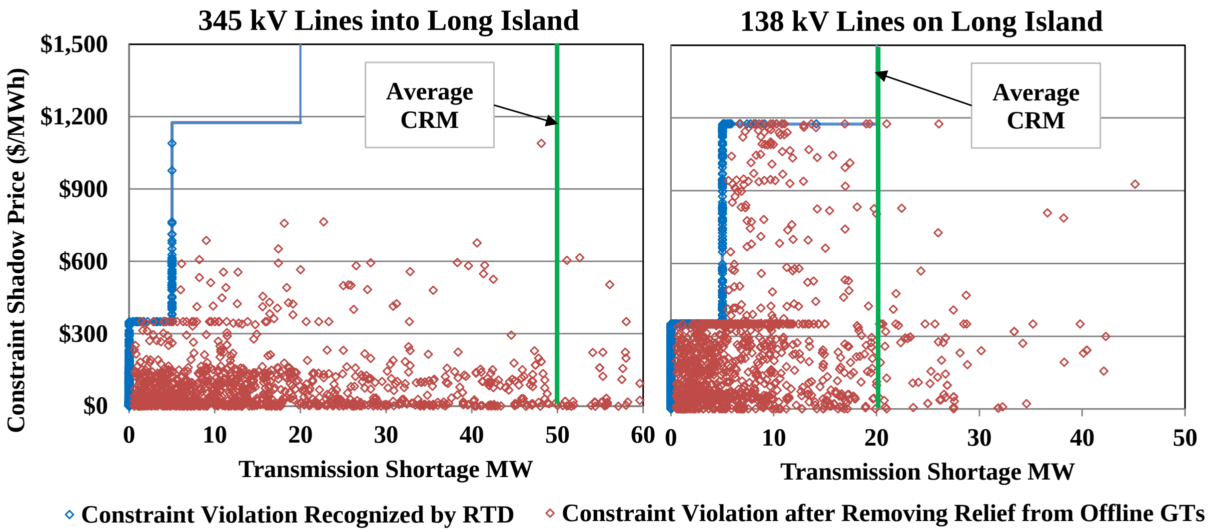
Table A-11: Constraint Limit and CRM in New York
During Real-Time Transmission Shortage Intervals, 2020

Constraint Voltage Class	Constraint Location	# of Constraint-Shortage Intervals		Avg Shortage MW		Avg Constraint Limit (MW)	Avg CRM (MW)	CRM as % of Limit
		Recognized in Model	Excluding Offline GT	Recognized in Model	Excluding Offline GT			
115 kV	**West**	2801	2801	5	5	209	10	5%
	North	344	348	4	4	132	10	8%
	All Others	629	629	8	8	152	10	7%
138 kV	**New York City**	2559	2654	5	6	257	20	8%
	Long Island	907	1917	2	7	292	24	8%
	All Others	335	451	5	5	286	20	7%
230 kV	**West**	509	509	26	26	701	45	6%
	North	145	148	11	11	357	20	6%
	All Others	29	32	6	6	537	20	4%
345 kV	**New York City**	39	109	3	16	830	20	2%
	North	3	3	6	6	1693	50	3%
	Long Island	131	1487	1	18	734	50	7%
	All Others	20	206	1	5	1331	22	2%

The table shows that offline GTs were used much more frequently to manage congestion on the transmission facilities on Long Island than in other regions in 2020. Therefore, Figure A-93 focuses on examining the price effects of offline GTs on transmission constraints on Long Island, grouped as: (a) the 345 kV transmission circuits from upstate to Long Island; and (b) the 138 kV transmission constraints within Long Island.

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-93: Transmission Constraint Shadow Prices and Violations
With and Without Relief from Offline GTs, 2020



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

- Constraint relaxation has been much less frequent following the revision of transmission shortage pricing in June 2017, occurring just 4 percent of all transmission shortages in 2020 (shown by the points that are off the GTDC curve in Figure A-92).
  - 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 10 MW CRM is currently used for modeled 115 kV transmission constraints in upstate New York, while a default 20 MW CRM is used for most facilities at voltage levels of 138 kV and above regardless of their actual physical limits.
  - On average, the default 20 MW CRM is roughly: (see Table A-11)
    - 2 to 3 percent of the transfer capability of the 345 kV constrained facilities;
    - 4 to 6 percent of the transfer capability of the 230 kV constrained facilities; and
    - 7 to 8 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 as the voltage level decreases.
    - 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 18 MW in 2020 (when excluding congestion-relief effect from offline GTs) 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.
    - We continue to recommend replacing the current single GTDC with multiple GTDCs that can vary according to the importance, severity, and/or duration of the transmission constraint violation.[366]
        - The NYISO has proposed modifications to the GTDC, which would be a significant improvement over the current GTDC.[367] This is because the MW-range of the proposed GTDC is based on the CRM of the constraint, while the current GTDC uses a 20-MW range regardless of the CRM value.
- The shadow prices that resulted from offline GT pricing were not well-correlated with the severity of the transmission constraint, leading to inefficient congestion prices during such conditions. (see Figure A-93).
    - Transmission constraints in downstate areas, particularly Long Island, were most impacted by this. (see Table A-11) The use of offline GT pricing limits the ability of the real-time market models to maintain transmission security in Long Island, so the NYISO uses significantly higher CRMs for key transmission facilities.
    - Thus, the use of offline GT pricing often leads the NYISO to constrain transmission flows at artificially low levels in Long Island, which leads to unnecessary generation dispatch and inflated production costs.
    - The resulting mismatch between modeled and actual flows leads to inefficient prices in broader areas that do not reflect the balance of supply and demand.

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366 See Recommendation #2015-17.

367 See “Constraint Specific Transmission Shortage Pricing”, by Kanchan Upadhyay, at November 21, 2019 MIWG meeting.

   - Therefore, we also recommend the NYISO eliminate offline fast-start pricing from the real-time dispatch model.[368]

I. Market Operations and Prices on High Load Days

Although the summer of 2020 was unexpectedly warm, load exceeded 30 GW on just one day because of the load-reducing effect of the COVID-19 pandemic. The NYISO did not activate any reliability demand response resources (i.e., EDRP/SCRs). Nonetheless, NYISO SREed resources for statewide capacity needs and local TOs activated various amounts of utility demand response resources.[369] This subsection evaluates prices under these market conditions.

Figure A-94 & Figure A-95: Market Operations and Prices on High Load Days

Figure A-94 and Figure A-95 summarize market outcomes on select high load days when SRE commitments were made by the NYISO to maintain adequate reserves and/or utility DR was deployed by TOs. Both figures report the following quantities in each interval of afternoon peak hours (HB 13 - HB 20) for NYCA:

- Available capacity from non-SRE resources – This includes three categories of unloaded capacity from online units and the capacity of offline peaking units up to the Upper Operating Limit:
   - 30-minute reserves that are scheduled by the market model;
   - 30-minute reserves that are available but are not scheduled by the market model; and
   - Additional capacity that is only available beyond 30 minutes of ramping.
- Schedules from SRE resources – This includes scheduled energy and total 30-minute reserves from SRE resources.
- Constraint shadow prices on the NYCA 30-minute reserve requirement.

In both figures, the solid black lines represent the NYCA 30-minute reserves requirement, which is 2620 MW. The dashed black lines show the quantity equal to the amount of deployed utility DR plus the NYCA 30-minute reserves requirement. The solid purple lines show the system surplus capacity that would be available had the SRE commitments not been made, which is estimated as the amount of available capacity from non-SRE resources minus energy schedules on SRE resources. Therefore, the difference between the solid black line and the solid purple line indicates the size of the shortage without the SRE commitments; and the difference between the dashed black line and the solid purple line indicates the size of the shortage without SRE commitments and utility DR deployments.

[368] See Recommendation #2020-2.

[369] See presentation "NYISO Summer 2020 Hot Weather Operations" by Wes Yeomans at 9/23 MC meeting for more details.

Figure A-94: SRE Commitments and Utility DR Deployment on High Load Days

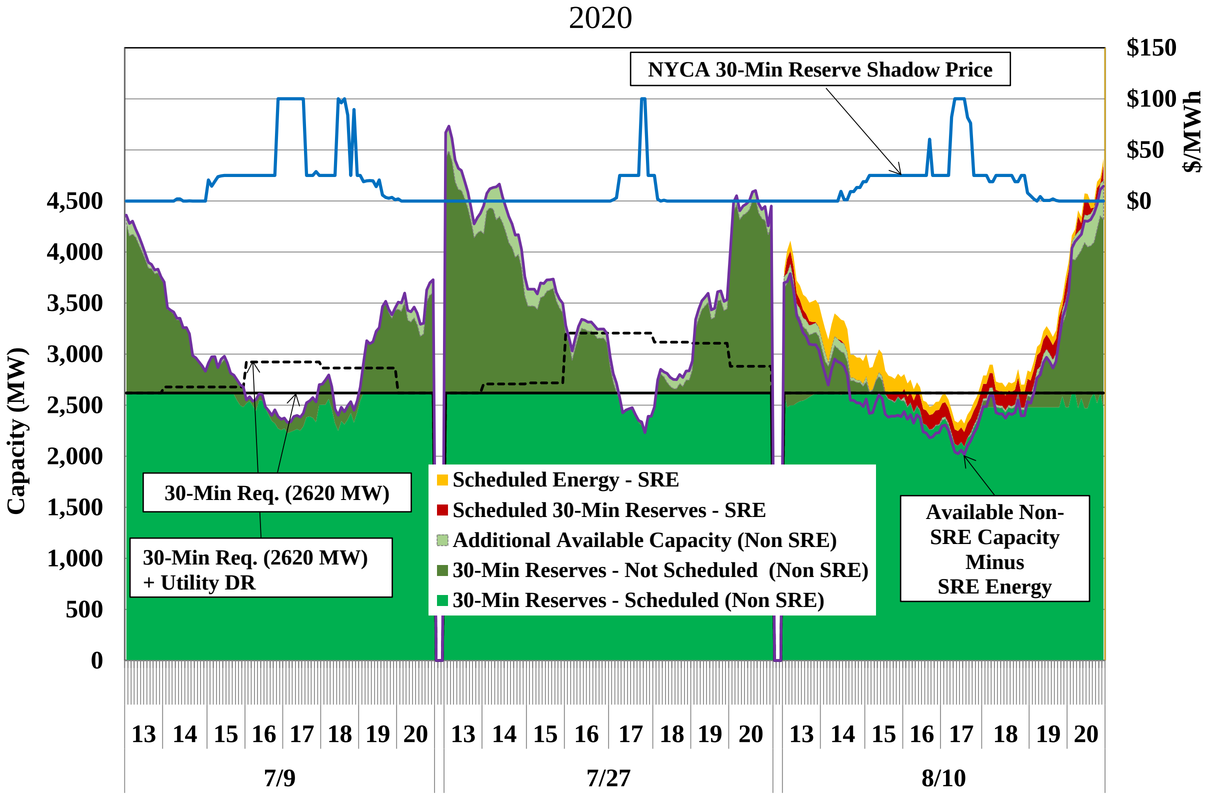
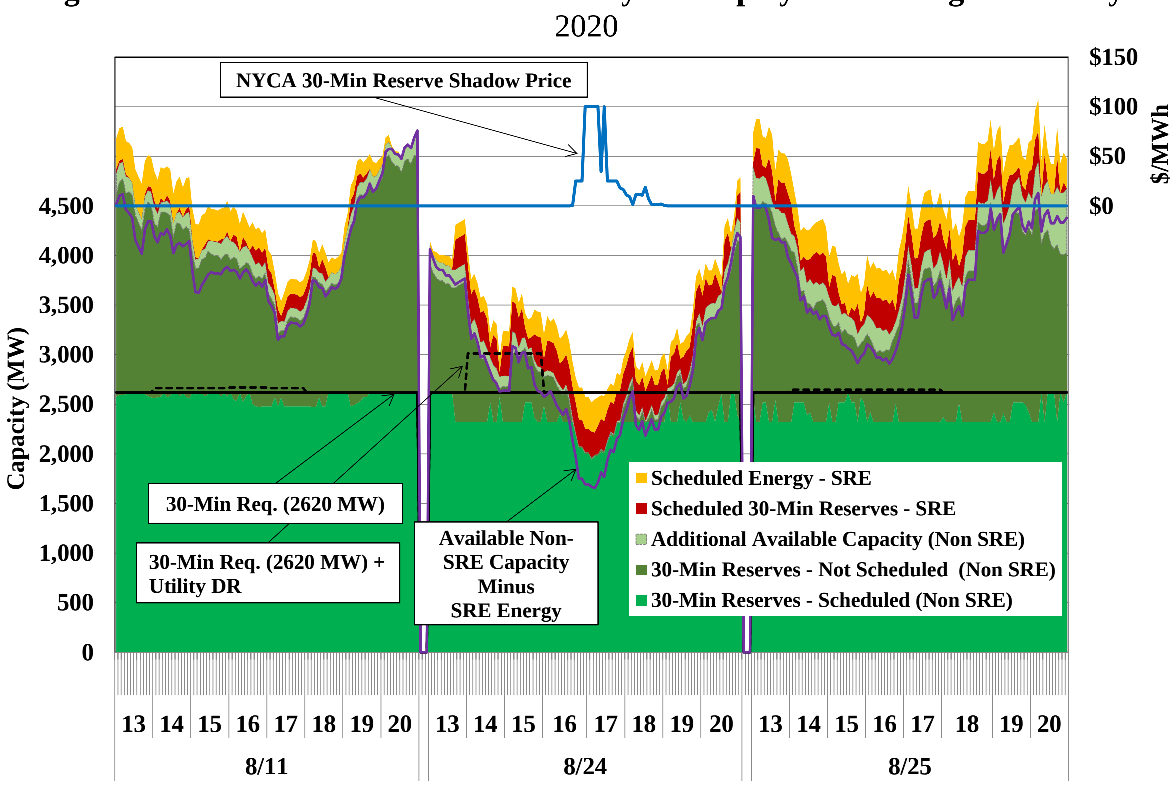


Figure A-95: SRE Commitments and Utility DR Deployment on High Load Days



Key Observations: Market Operations and Prices on High Load Days

- Summer load peaked at 30.7 GW on July 27, roughly 5 percent below the 50/50 forecast of 32.3 GW.
  - Despite several heat waves this summer, load exceeded 30 GW on just one day because of the load-reducing effect of the Covid-19 pandemic.
- NYISO did not activate any EDRP/SCRs in the summer of 2020. However, NYISO SREed resources for statewide capacity needs on four days.
  - Our evaluation suggests that, in retrospect, SREs were needed to prevent brief NYCA capacity deficiencies on August 10 and 24, but they were not needed on August 11 and 25.
    - On August 11 and 25, actual load was far below forecast (by ~1-2 GW), and 30-minute reserves were priced at $0/MWh during afternoon peak hours.
  - Although the additional costs associated with these SREs (i.e., BPCG uplift) were not large in this period, they were incurred to satisfy reserve needs that are not fully reflected in the day-ahead market.
- In addition, various amounts of Utility DR were activated on 21 days in the summer, although the quantity exceeded 100 MW on just 8 days.
  - Roughly half of utility DR activations on these eight days were for peak-shaving and distribution system security in New York City and the other half for peak-shaving outside NYC.
  - The statewide DR quantity ranged up to nearly 550 MW on July 27 (when NYCA peak demand was roughly 30.7 GW).
  - Utility DR deployments are not considered when NYISO evaluates whether to SRE or deploy emergency DR resources, which can lead to unnecessary OOM actions.
- Utility DR deployments helped avoid a brief NYCA capacity deficiency on just two days (7/9 and 7/27), while the economics of the energy market did not indicate a need for peak load reduction on most of the other days with utility DR deployments.
  - Utility programs often provide large availability payments (~$1,000/MWh) for peak-shaving that are far above the value of the load reduction in the real-time market.

J. 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-96: 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.

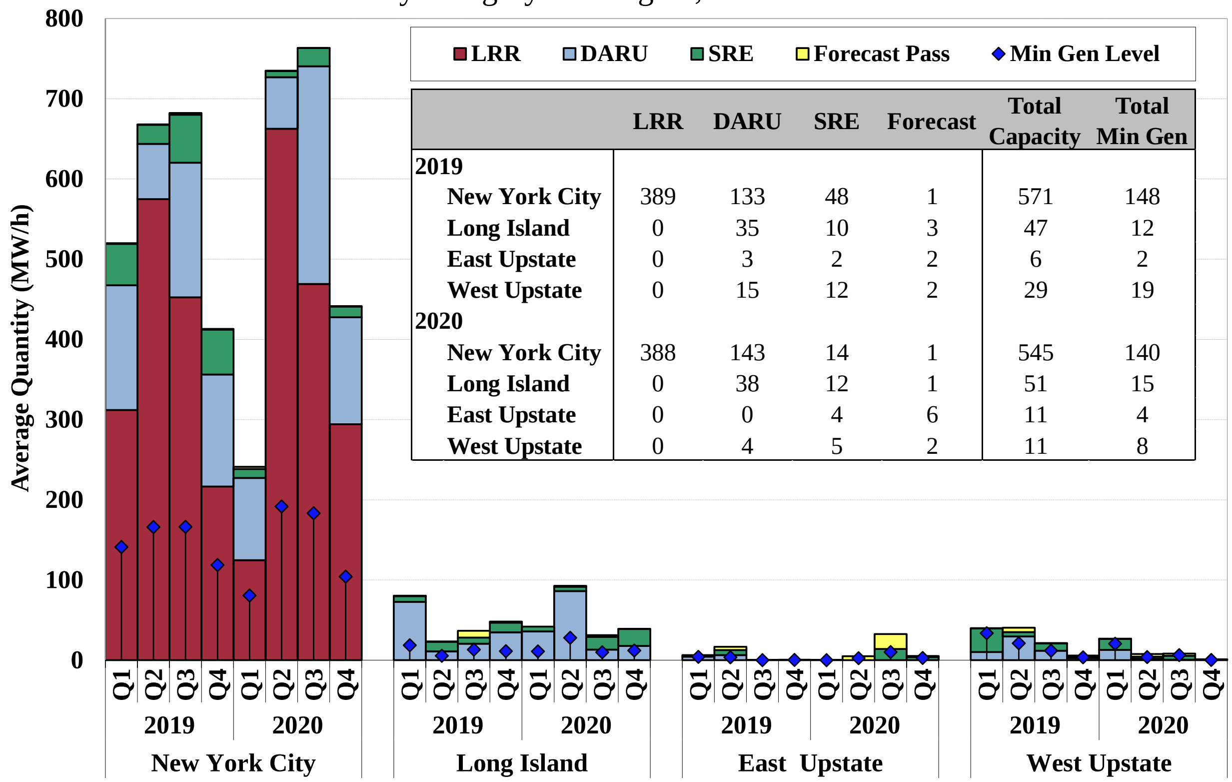
Generators that are committed for reliability are generally not economic at prevailing market prices, but they affect the market by: (a) reducing prices from levels that would otherwise result from a purely economic dispatch; and (b) increasing non-local reliability uplift since a portion of the uplift 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-96 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 2019 and 2020. 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 2019 and 2020 on an annual basis.

Figure A-96: Supplemental Commitment for Reliability in New York
By Category and Region, 2019 – 2020



	LRR	DARU	SRE	Forecast	Total Capacity	Total Min Gen
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
2020						
New York City	388	143	14	1	545	140
Long Island	0	38	12	1	51	15
East Upstate	0	0	4	6	11	4
West Upstate	0	4	5	2	11	8

Figure A-97: Forecast-Pass Commitment in New York

The forecast pass of SCUC (after the economic pass) commits any additional physical resources that maybe needed to meet the forecasted load. Figure A-97 examines this process in 2020, summarizing the following quantities on a daily basis:

- *Forecast Required Energy for Dispatch* – This summarizes the difference between NYISO forecasted load and scheduled physical energy in the economic pass, in total MWh for each day; and

- *Forecast-Pass Committed Capacity* – This summarizes additional capacity committed in the forecast pass to meet NYISO forecast load, in total MWh for each day. The reported quantity only includes capacity from internal slow-start resources in the hours where it is not online in the economic pass but is online in the forecast pass.

Figure A-97: Forecast-Pass Commitment in New York
By Day, 2020

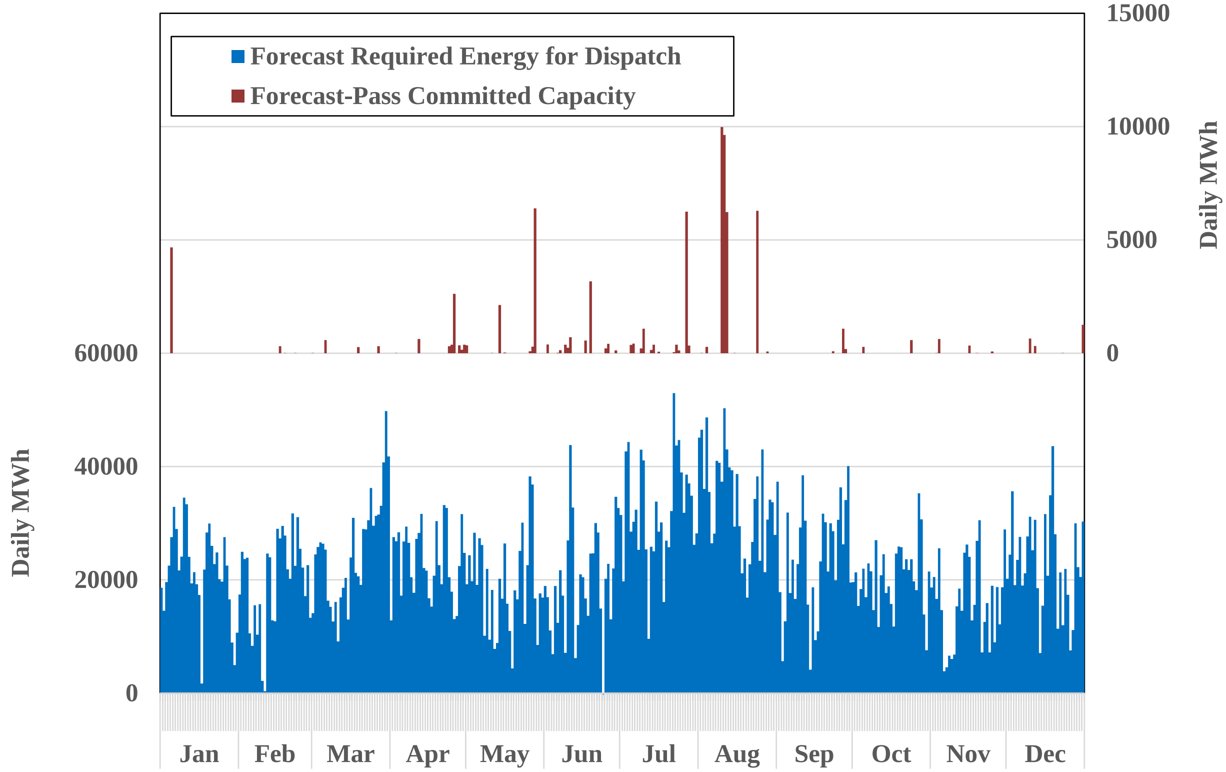


Figure A-98: Supplemental Commitment for Reliability in New York City

Most supplemental commitment for reliability occurred in New York City. Figure A-98 summarizes an analysis that identifies the causes for the reliability commitments in New York City. Specifically, Figure A-98 shows the minimum generation committed for reliability by reliability reason and by location in New York City during 2019 and 2020.

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: [370]

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

- 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-1-1-0 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-1-1-0 scenario.
- NOx – If needed for the NOx bubble requirement.[371] 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-1-1-0 scenario.
- Loss of Gas – If needed to protect NYC against a sudden loss of gas supply and no other reason except NOx.[372]

In Figure A-98, for N-1-1-0 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
- FRLP - Freshkills Load Pocket
- GSLP - Greenwood/Staten Island Load Pocket; and
- SDLP - Sprainbrook Dunwoodie Load Pocket.

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371 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 here.

372 See *NYSRC Reliability Rules & Compliance Manual*, Version 35, See Section G.2 Local Area Operation: Loss of Gas Supply – New York City, Requirement R1.

Figure A-98: Supplemental Commitment for Reliability in New York City
By Category and Region, 2019 – 2020

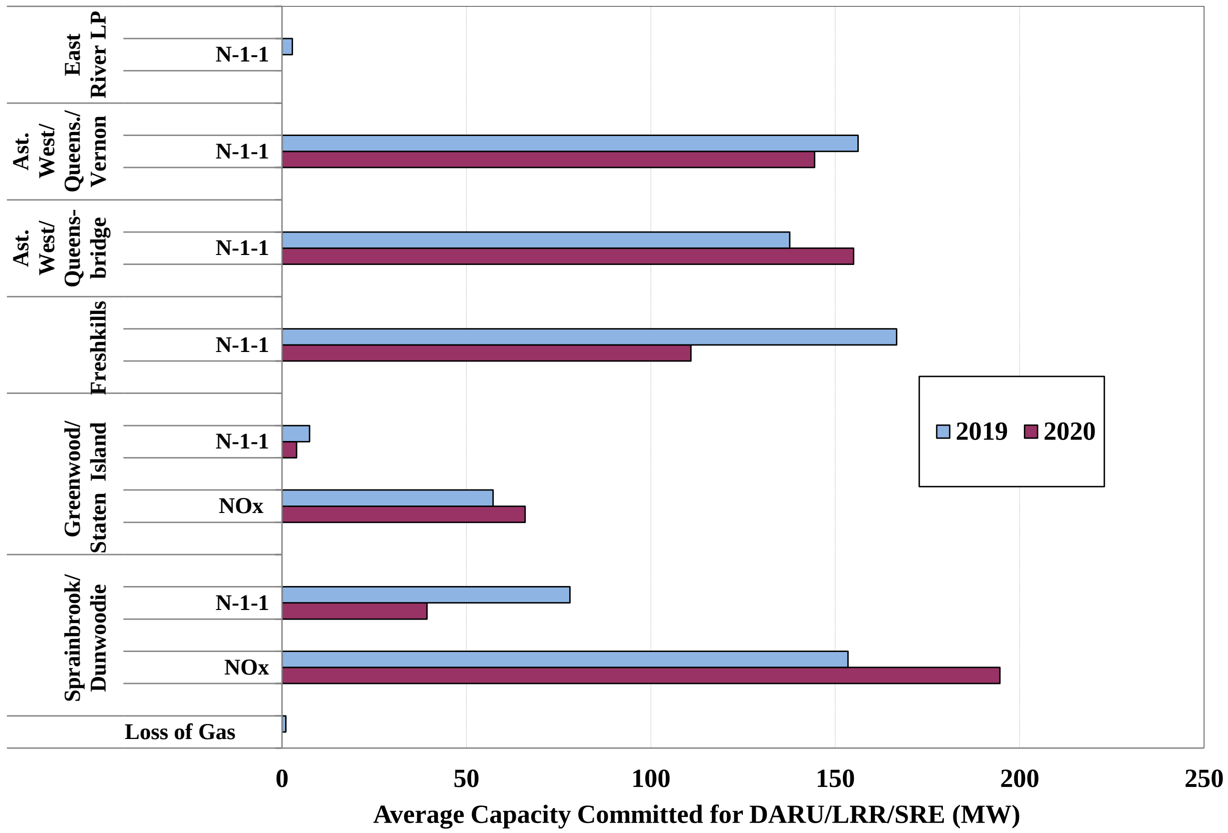


Figure A-99 & Figure A-100: Excess LRR Commitment in New York City

Reliability commitments in New York City often occur because a generator is needed only during the highest load hours of day. The actual amount of capacity needed in each load pocket varies by hour based on load and network conditions. However, the day-ahead market model applies a single daily capacity requirement to all hours for most load pockets. This can lead to over-commitment, especially in off-peak hours, raising production costs and depressing market clearing prices.

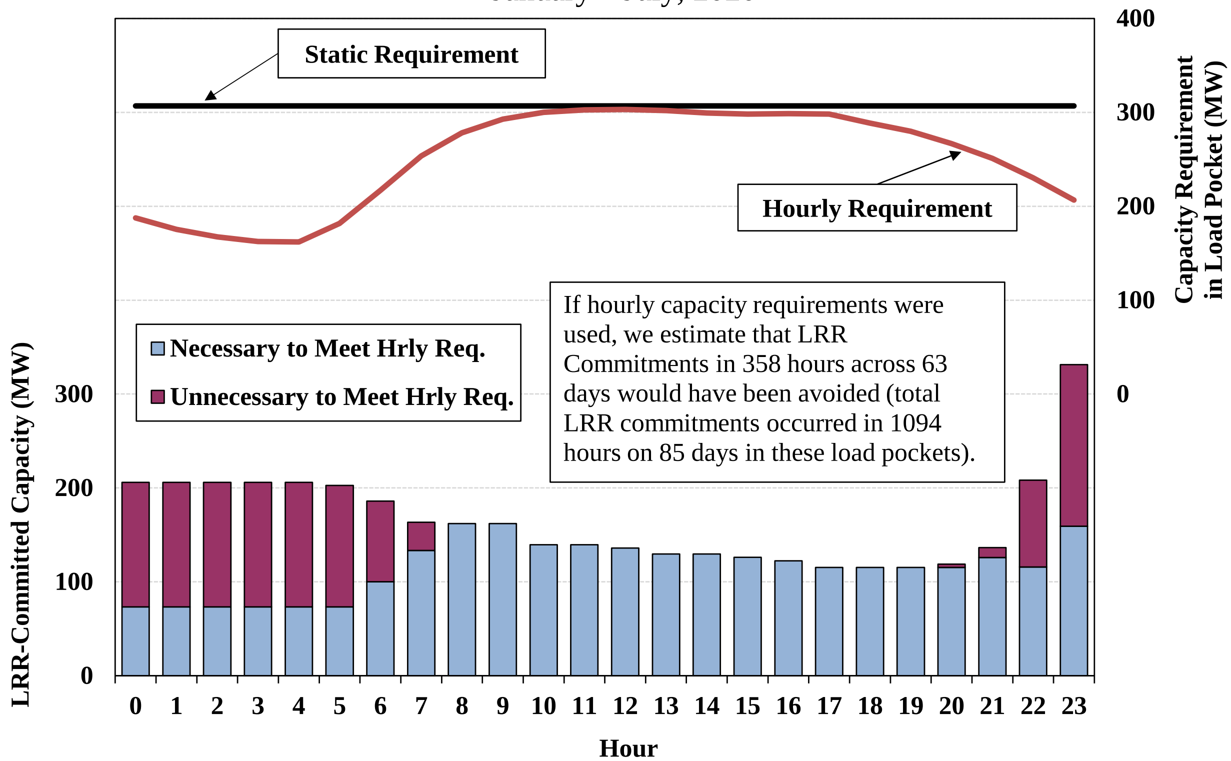
Figure A-99 shows our evaluation of how much of the capacity committed to satisfy an N-1-1 constraint may have been unnecessary had the daily requirements been calculated hourly instead. The figure shows the following quantities as the averages for each hour on days when one or more units were committed to satisfy an LRR constraint:

- The static daily requirement, compared to the varying hourly requirement (in the top portion of the chart);
- Capacity that was LRR-committed based on the daily requirement, separated into two portions: (a) capacity necessary to satisfy the hourly requirement; and (b) capacity unnecessary to satisfy the hourly requirement.

This evaluation is done for the load pockets that accounted for most of the LRR-commitments of combined-cycle units in New York City. Steam turbines usually have long lead time, minimum run time, and minimum down time constraints, so replacing the static daily requirement with the varying hourly requirement generally won't directly affect commitments of steam turbines.

Figure A-99: Excess LRR Commitment in NYC Using Static Daily Requirement

January – July, 2020



The NOx rule prevents New York City GTs in two portfolios from generating during the Ozone season (i.e., May 1 to September 30) unless steam turbines in the same portfolios are also producing such that the portfolio-average NOx emission satisfies the DEC's standard. For this reason, steam units in New York City are often LRR-committed solely to satisfy the NOx Bubble requirement in the Ozone season. However, on many of these days, even if both the committed steam turbine and its supported gas turbines were unavailable, all N-1-1 criteria could be satisfied by other resources. This suggests that such commitments are not necessary on some days in the Ozone season. Figure A-100 shows our evaluation of the necessity during the Ozone season of 2020.

The figure shows the daily minimum supply margin in the relevant load pockets after the removal of the NOx-committed STs and their supported GTs in the NOx Bubble. The evaluation is done on days when the ST is NOx-only committed in the day-ahead market. A positive minimum supply margin indicates that both the ST and associated GTs are not needed to satisfy any N-1-1 criteria in the load pocket, while a negative supply margin indicates that a portion of the ST and/or associated GTs are needed.

Figure A-100: Excess NOx-Rule LRR Commitment in New York City
Ozone Season, 2020

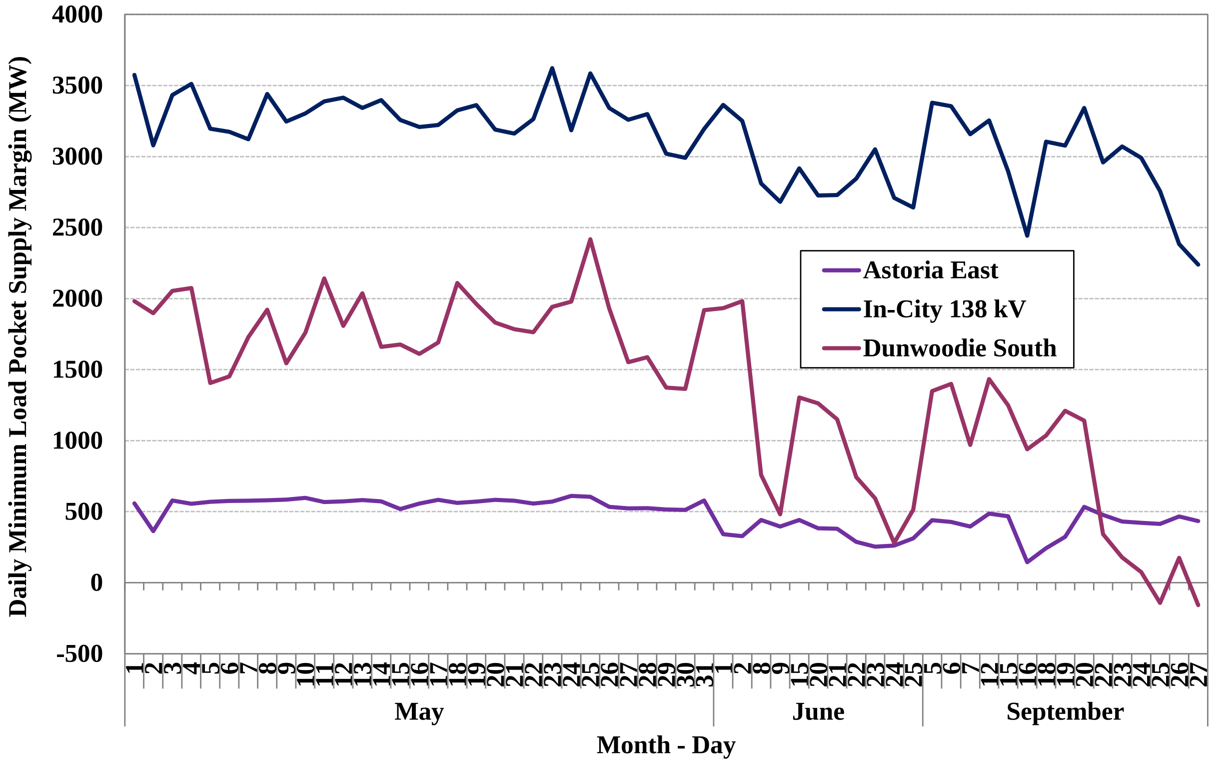


Table A-12: Day-ahead Reserve Price Estimates for Selected NYC Load Pockets

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) covers the generator's production costs, 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 2020 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 2020 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 Freshkills load pocket on Staten Island. 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
2020

Area	Average Marginal Commitment Cost ($/MWh)
NYC 345 kV System	$1.99
Selected 138 kV Load Pockets:	
Astoria West/Queensbridge	$3.26
Vernon	$2.61
Freshkills	$2.95

<u>Key Observations: Reliability Commitment</u>

- Reliability commitment averaged roughly 620 MW in 2020, down modestly from 2019.
  - New York City accounted for 88 percent of total reliability commitment in 2020 and saw a modest reduction of 5 percent from a year ago.
    - Reliability commitment fell notably in the first quarter from a year ago. The reduction resulted from procedural changes that reduced supplemental

commitments at the Arthur Kill plant when it was not actually needed for local reliability.

- Reliability comments in other areas were relatively infrequent in 2020. Most were DARU commitments on Long Island for reliability and congestion management on the 69 kV network.

- We identified two types of excess reliability commitments in New York City, which depress prices, generate uplift, and can cause excess production costs.
  - The first type resulted from using a single daily capacity requirement in all 24 hours for most load pockets, leading to over-commitment in off-peak hours. (see Figure A-99)
    - We estimated that, if hourly capacity requirements were used, LRR Commitments in 358 hours across 63 days (in the period from January to July 2020) would have been avoided.
    - The NYISO began to apply these capacity requirements on an hourly (rather than daily) basis beginning July 30 in the day-ahead market, which have reduced the amount of LRR commitments in off-peak hours.
  - The second type was related to the NOx Bubble requirement. (see Figure A-100)
    - A steam turbine was committed solely to satisfy the NOx rule on 68 days during the Ozone season of 2020. Our evaluation showed that even if the committed steam turbine and the associated GTs were unavailable, all N-1-1-0 criteria in the associated load pockets could have been satisfied by (a) other committed resources on 55 of these days or (b) lower-cost resources on two of these days.
    - This suggests that these NOx-only steam turbine commitments could have been avoided if the market software was allowed to consider whether the GTs were actually needed for reliability (before committing the associated steam turbine).

- 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 $1.99/MWh in most areas to as much as $3.26/MWh in the Astoria West/Queensbridge load pocket in 2020.
  - We have recommended the NYISO model local reserve requirements in New York City load pockets.[373]
    - In the Reserve Enhancements for Constrained Areas project, the NYISO is studying ways to model a dynamic reserve allocation, which has potential to

[373] See Recommendation #2017-1.

greatly improve the pricing of reserves in certain NYC load pockets.[374] We support this effort.

- When economically scheduled bid load was well below the forecasted load in the day-ahead market, the forecast pass of SCUC may commit additional physical resources to ensure that sufficient physical resources are available to satisfy the forecasted load in the real-time market.
  - Physical energy scheduled to serve bid-in load was often lower than forecasted load in the day-ahead market.
    - The amount of Forecast Required Energy for Dispatch ("FRED"), which indicates the physical energy shortfalls to meet forecasted load, averaged roughly 23,200 MWh (or nearly 1 GW per hour) in 2020. Thus, the NYISO routinely holds large amounts of operating reserves on capacity that is not scheduled in the day-ahead market.
  - However, forecast-pass commitment occurred very infrequently as surplus capacity from physical resources (from the economic pass) was sufficient on most days.
    - In 2020, forecast-pass committed capacity exceeded 1000 MWh on 13 days.
  - This reliability need is not currently reflected in market prices.
    - The surplus capacity on economically-committed physical resources that can satisfy FRED is currently treated as free reserves.
    - Additional resources committed in the forecast pass to satisfy FRED typically incur uplift payment.
    - It would be beneficial to consider modeling this reliability need as a reserve requirement and to procure and price the needed amount through the market as part of the effort to set operating reserve requirements dynamically. Specifically, the NYISO could procure sufficient 30-minute reserves in the day-ahead market to cover the 30-minute reserve requirement plus the differential between forecasted load and the energy scheduled from physical resources (i.e., not virtual supply).[375]

Figure A-101: Frequency of Out-of-Merit Dispatch

Figure A-101 summarizes the frequency (i.e., the total station-hours) of OOM actions on a quarterly basis in 2019 and 2020 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.

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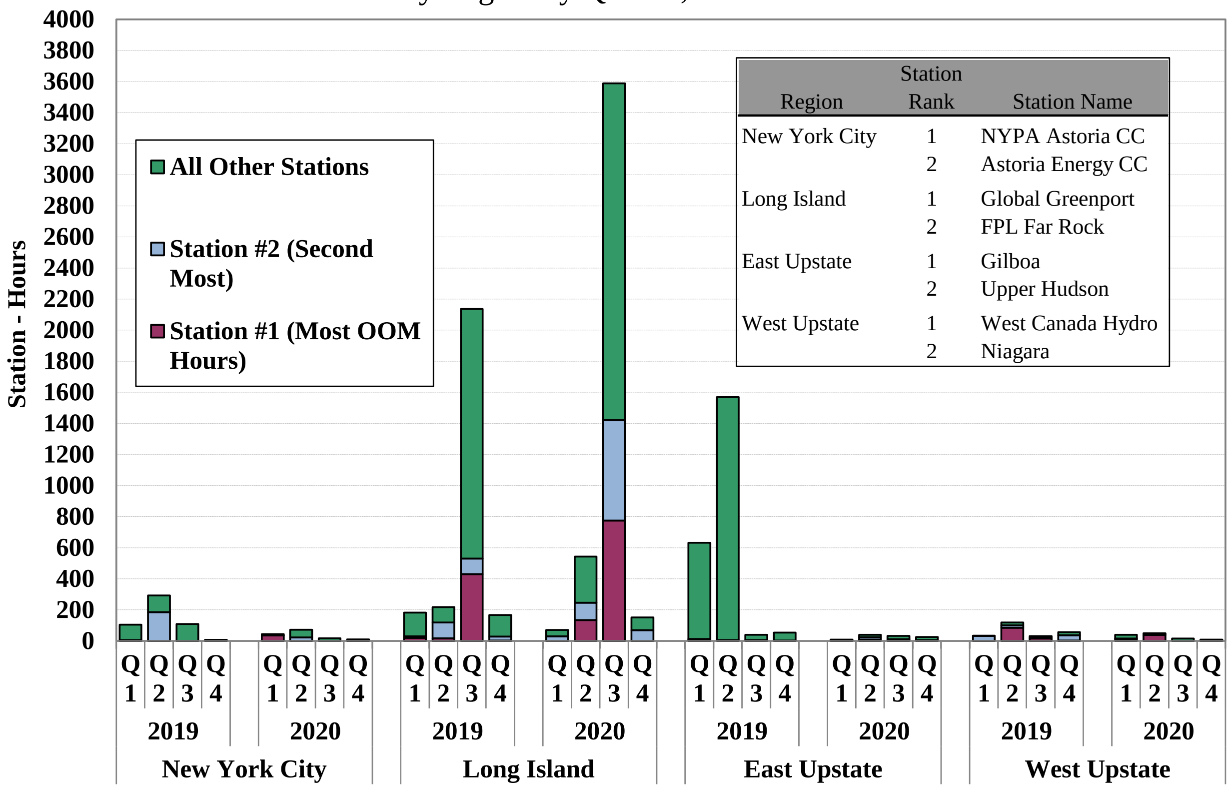
374 See the presentation "Coordination of Energy & Ancillary Service Projects", by Mike DeSocio at BIC meeting on August 12, 2020.

375 See Recommendation #2015-16.

In each region, the two stations with the highest number of OOM dispatch hours during 2020 are shown separately from other stations (i.e., "Station #1" is the station with the highest number of OOM hours in that region during 2020, 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-101: Frequency of Out-of-Merit Dispatch
By Region by Quarter, 2019 - 2020



Key Observations: OOM Dispatch [376]

- Generators were dispatched Out-of-Merit ("OOM") for roughly 4,700 station-hours in 2020, down 18 percent from 2019.
    - The overall reduction was driven primarily by the decrease in the East Upstate region, where OOM actions to manage post-contingency flow on the Albany-Greenbush 115 kV facility were greatly reduced following the transmission upgrades in mid-2019.
- Unlike in other regions, OOM levels on Long Island, which accounted for 92 percent of all OOM actions in 2020, rose roughly 60 percent from 2019 to 2020.
    - 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

376 A detailed evaluation of the actions used to manage low-voltage network congestion in New York is provided in Appendix Section III.D.

network and voltage needs on the East End of Long Island during high load conditions.

- The need for OOM actions increased in the summer of 2020 as a result of:
  - Higher load levels driven by warmer weather and higher residential load because of the COVID-19 pandemic; and
  - Lengthy transmission outages of the Cross Sound Cable and the Neptune interface.

- OOM levels outside Long Island have been falling significantly in 2019 and 2020 because most 115 kV facilities that were previously managed by OOM actions have been managed by the market models since December 2018.
  - To further reduce OOM actions and improve market efficiency in scheduling and pricing, 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.[377]

K. 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-102 and Figure A-103 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.

[377] See Recommendation #2018-1.

- 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-102 & Figure A-103: Uplift Costs from Guarantee Payments

Figure A-102 shows the seven categories of uplift costs associated with guarantee payments on a monthly basis for 2019 and 2020. 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-103 shows the seven categories of uplift charges on a quarterly basis in 2019 and 2020 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-102: Uplift Costs from Guarantee Payments by Month
2019 – 2020

Year	BPCG By Category (Million $)								
	Local				Statewide				Total
	Day Ahead	Real Time	DAMAP	Min Oil Burn	Day Ahead	Real Time	DAMAP	EDRP/ SCR	
2020	$17	$15	$0	$0	$1	$5	$3	$0	$41
2019	$24	$13	$1	$0	$4	$7	$2	$0	$52

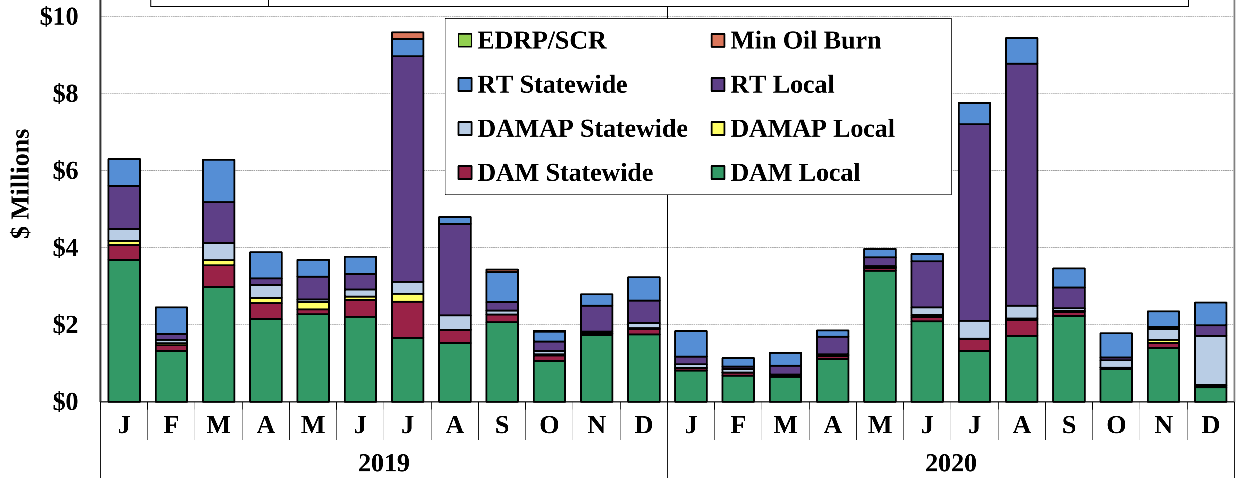
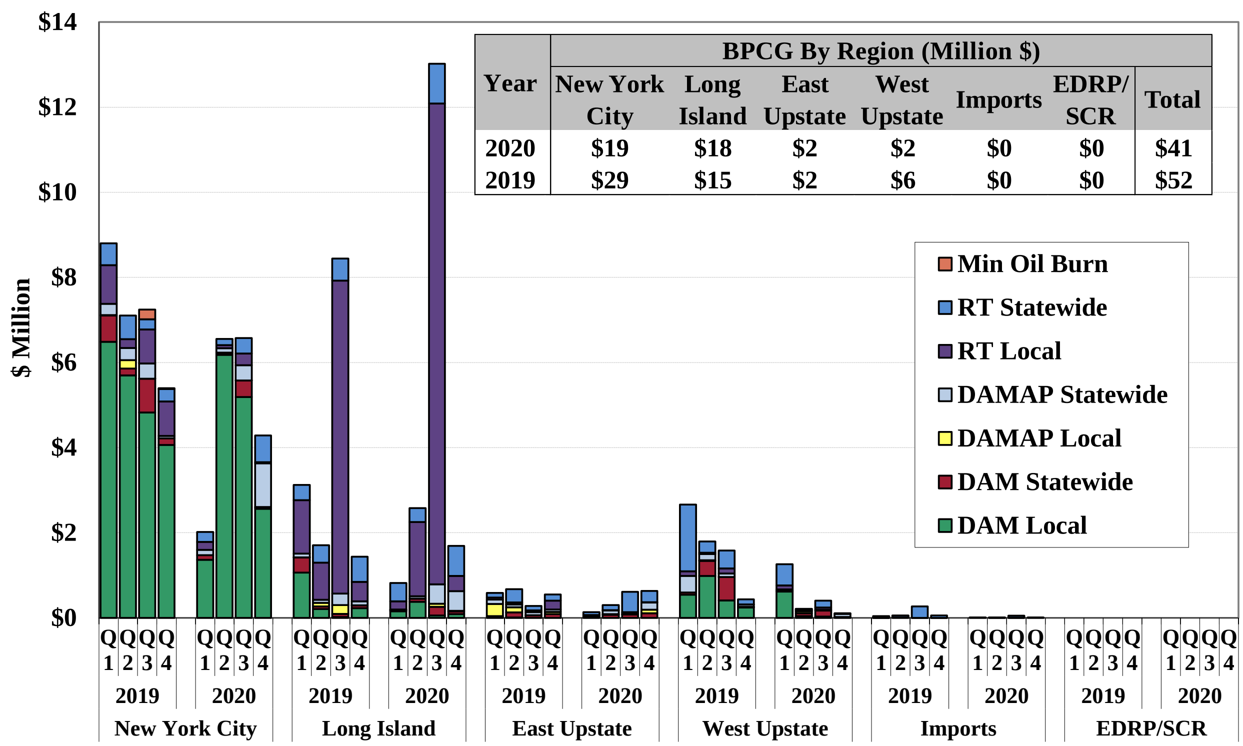


Figure A-103: Uplift Costs from Guarantee Payments by Region
2019 – 2020

Year	BPCG By Region (Million $)						
	New York City	Long Island	East Upstate	West Upstate	Imports	EDRP/ SCR	Total
2020	$19	$18	$2	$2	$0	$0	$41
2019	$29	$15	$2	$6	$0	$0	$52



It is also noted that Figure A-102 and Figure A-103 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 21 percent from $52 million in 2019 to $41 million in 2020. This was driven primarily by lower gas prices, which decreased the commitment costs of gas-fired units.
- New York City accounted for $19 million (or 46 percent) of BPCG in 2020.
  - Over $15 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. [378]
- In spite of the reduction in other regions, Long Island saw an increase in BPCG uplift from $15 million in 2019 to $18 million in 2020.
  - The increase occurred primarily in the category of real-time local BPCG uplift as high-cost peaking resources were OOMed more frequently in the summer months to manage 69 kV congestion and local voltage needs (for the reasons discussed earlier) .
    - Nearly $14 million of BPCG uplift were paid for this purpose.
    - 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. [379]

L. Potential Design of Dynamic Reserves for Constrained Areas

This subsection describes a modeling approach with which locational reserve requirements and associated price signals could be dynamically determined based on load, transmission capability, and online generation. This modeling approach is described for an import-constrained area, such as load pockets in New York City, where locational reserve requirements are developed to satisfy local N-1, N-1-1, and N-1-1-0 reliability criteria. But we identify five examples in Recommendation #2015-16 where this modeling approach would provide significant benefit.

General Mathematical Problem Formulation for Dynamic Reserves

We first describe the general problem formulation when local (N-1, N-1-1, and N-1-1-0) reserve requirements are set "dynamically." The reserve requirement formulation should be consistent

378 See Recommendation #2017-1.

379 See Recommendation #2018-1.

with reliability criteria. Based on NYSRC reliability rules, the general modeling of reserve requirements for a load pocket in New York City may take the following form:

- ∑(GenMW_i + Res10MW_i) >= CapReq_10Min (1)
- ∑(GenMW_i + Res10MW_i + Res30MW_i) >= CapReq_30Min (2)
- ∑(GenMW_i + Res10MW_i + Res30MW_i + Res60MW_i) >= CapReq_60Min (3)

Where "i" represents each qualified generator inside the load pocket, GenMW is the energy schedule, and Res10MW, Res30MW, and Res60MW are 10-minute, 30-minute, and 60-minute reserves schedules.

- CapReq_10Min = Load Pocket Load Forecast – N-1 Post-Contingency LTE Capability
- CapReq_30Min = Load Pocket Load Forecast – N-1-1 Post-Contingency LTE Capability
- CapReq_60Min = Load Pocket Load Forecast – N-1-1-0 Post-Contingency NORM Capability

For a Line N-1 constraint,

- N-1 Post-Contingency LTE Cap = Import Total LTE Rating – Line 1 LTE Rating (1.1)

For a Gen N-1 constraint,

- N-1 Post-Contingency LTE Cap = Import Total LTE Rating (1.2)

For a Line-Line N-1-1 constraint,

- N-1-1 Post-Contingency LTE Cap =

  Import Total LTE Rating – Line 1 LTE Rating – Line 2 LTE Rating (2.1)

- N-1-1-0 Post-Contingency NORM Cap =

  Import Total NORM Rating – Line 1 NORM Rating – Line 2 NORM Rating (3.1)

For a Line-Gen N-1-1 constraint,

- N-1-1 Post-contingency LTE Cap =

  Import Total LTE Rating – Line 1 LTE Rating (2.2)

- N-1-1-0 Post-Contingency NORM Cap =

  Import Total NORM Rating – Line 1 NORM Rating (3.2)

Where Line 1 and Line 2 refer to the first and second largest Line contingencies.

The largest generator in the load pocket is excluded from the left-hand sides of Equations (1.2), (2.2), and (3.2) for Gen N-1 and Line-Gen N-1-1 constraints. Furthermore, when these are modeled in the day-ahead market, virtual supply and other non-physical sales are excluded from the left-hand sides of the constraints listed above.

The Constraint (3) reflects the commitment requirement based on the N-1-1-0 operating criteria in New York City. Although this requirement is currently modeled via the LRR constraint in the day-ahead market only, the Constraint (3) should be included in both the day-ahead and real-time markets in the future design to reflect the consistent need. A 60-minute product in real-time will likely incent units to be more flexible in real-time as well.

Pricing Logic for Dynamic Reserve Formulation

The following discusses how the shadow prices for dynamic reserve requirements are used in setting reserve clearing prices and energy LBMPs.

Combine all equations and rewrite the constraints for a Load Pocket, LP^k, as follows:

- $\sum_{i \in LP^k}(GenMW_i + Res10MW_i) \geq \ Load\ Forecast - Total\ LTE + Line\ 1\ LTE$ (1.1)
- $\sum_{i \in LP^k, i \neq LG}(GenMW_i + Res10MW_i) \geq \ Load\ Forecast - Total\ LTE$ (1.2)
- $\sum_{i \in LP^k}(GenMW_i + Res10MW_i + Res30MW_i) \geq \ Load\ Forecast - Total\ LTE + Line\ 1\ LTE + Line\ 2\ LTE$ (2.1)
- $\sum_{i \in LP^k, i \neq LG}(GenMW_i + Res10MW_i + Res30MW_i\ ) \geq \ Load\ Forecast - Total\ LTE + Line\ 1\ LTE$ (2.2)
- $\sum_{i \in LP^k}(GenMW_i + Res10MW_i + Res30MW_i + Res60MW_i) \geq \ Load\ Forecast - Total\ NORM + Line\ 1\ NORM + Line\ 2\ NORM$ (3.1)
- $\sum_{i \in LP^k, i \neq LG}(GenMW_i + Res10MW_i + Res30MW_i + \ Res60MW_i\ ) \geq \ Load\ Forecast - Total\ NORM + Line\ 1\ NORM$ (3.2)

Where LG denotes the largest online generator in the Load Pocket LP^k.

Assume that $SP_{1.1}, SP_{1.2}, SP_{2.1}, SP_{2.2}, SP_{3.1}, SP_{3.2}$ are the constraint shadow prices for these constraints, respectively, then:

- $Reserve\ Price\ Adder_{10min} = \begin{cases} SP_{1.1} + SP_{1.2} + SP_{2.1} + SP_{2.2} + SP_{3.1} + SP_{3.2}, & i \in LP^k, but\ i \neq LG \\ SP_{1.1} + SP_{2.1} + SP_{3.1}, i = LG \end{cases}$
- $Reserve\ Price\ Adder_{30min} = \begin{cases} SP_{2.1} + SP_{2.2} + SP_{3.1} + SP_{3.2}, & i \in LP^k, but\ i \neq LG \\ SP_{2.1} + SP_{3.1}, i = LG \end{cases}$

- $Reserve\ Price\ Adder_{60min} = \begin{cases} SP_{3.1} + SP_{3.2}, & i \in LP^k, but\ i \neq LG \\ SP_{3.1}, i = LG \end{cases}$

- $LBMP\ Adder = \begin{cases} SP_{1.1} + SP_{1.2} + SP_{2.1} + SP_{2.2} + SP_{3.1} + SP_{3.2}, & i \in LP^k, but\ i \neq LG \\ SP_{1.1} + SP_{2.1} + SP_{3.1}, i = LG \end{cases}$

These price adders will be reflected in final energy and reserve prices for individual resources. This pricing logic has the following implications:

- Besides the difference in loss and congestion, energy prices at different locations will also reflect different values for satisfying local reliability needs, which are shown by the LBMP adder.

- Energy prices for virtual supply may be lower than energy prices for physical supply (at the same location) in the day-ahead market. This is because the shadow costs of above-mentioned constraints are applied to physical energy only. This market outcome is generally desirable because higher LBMPs for physical energy reflect their additional values for satisfying local reliability needs.

- Energy and reserves prices for the largest generator in the load pocket may be lower than other generators in the load pocket. This is because the shadow costs of the N-1 Generator, and N-1-1 and N-1-1-0 Line-Generator Constraints are applied to all generators in the load pocket except the largest unit. There may be different settlement options to consider (from market incentive perspective) for the largest unit in the load pocket. One way is to pay the largest unit the lower market clearing price. An alternative way is to pay the largest unit the same price (as for other units in the load pocket) but add a charge for extra reserve costs incurred because of the generation contingency.

An Illustrative Example

The following provides a stylized example to illustrate how dynamic reserves requirements would affect reserve clearing prices and LBMPs under typical conditions in a load pocket. It contrasts market outcomes under the current design where local reserve needs are met through out-of-market commitment with outcomes when local reserve requirements are considered.

Description of the Simulated System

As shown in Figure A-104, the example system has two areas, A and B, where B is a load pocket. There are four lines connecting A and B, with their Norm and LTE line ratings labeled in the figure.

Figure A-104: Illustrative Diagram of the example system

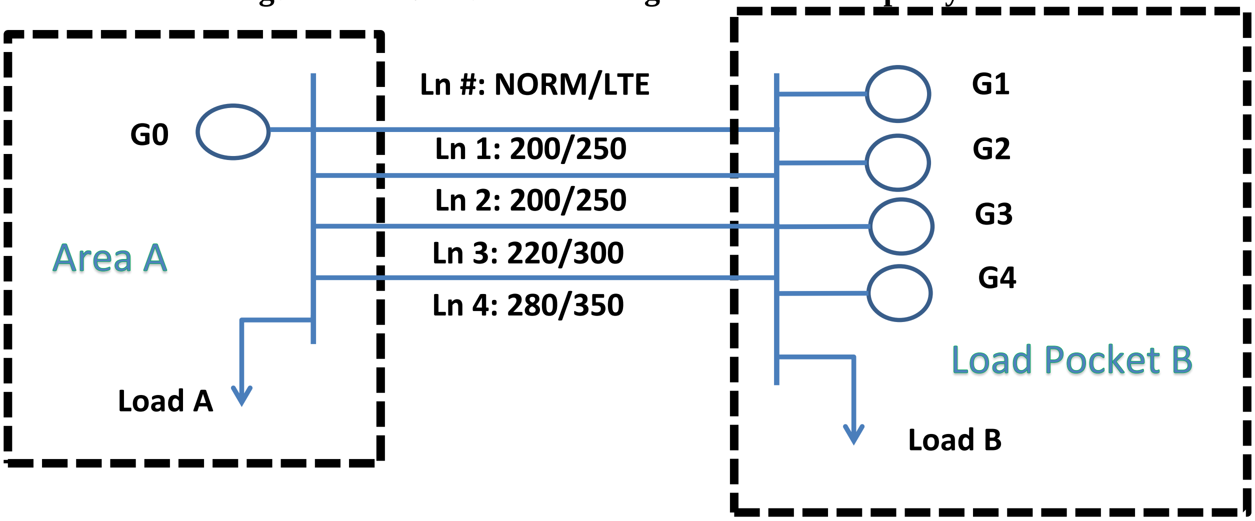


Table A-13 lists assumed physical parameters for the five generators in the example system. G0 represents the aggregation of less expensive generation in Area A, while G1 represents a slow-moving ST in the load pocket, which is also the largest generator in the pocket. G2 and G3 represent two CCs, and G4 represents a Bayonne-type facility that is capable of starting-up in 10 minutes.

Table A-13. Generator Physical Parameters

Generator	MinGen (MW)	UOL (MW)	Ramp Rate (MW/Min)	Fast Start
G0	200	3500	40	N
G1	75	300	3	N
G2	125	210	6	N
G3	120	200	6	N
G4	0	200	20	10Min

The example also assume that:

- 1500 MW of load in Area A
- 1100 MW of load in Load Pocket B
- Fixed reserve requirements are used at the system level, which are:
  - 150 MW of 10-minute spinning reserve requirement;
  - 300 MW of 10-minute total reserve requirement; and
  - 600 MW of 30-minute total reserve requirement.

Constraints (1.1)-(3.2) listed above, referred herein as Dynamic Reserve Constraints, are implemented for the Load Pocket B as follows,

- $\sum_{i\in\{1,2,3,4\}}(GenMW_i + Res10MW_i) \geq 300$ (1.1)
- $\sum_{i\in\{2,3,4\}}(GenMW_i + Res10MW_i) \geq -50$ (1.2)
- $\sum_{i\in\{1,2,3,4\}}(GenMW_i + Res10MW_i + Res30MW_i) \geq 600$ (2.1)
- $\sum_{i\in\{2,3,4\}}(GenMW_i + Res10MW_i + Res30MW_i) \geq 300$ (2.2)
- $\sum_{i\in\{1,2,3,4\}}(GenMW_i + Res10MW_i + Res30MW_i + Res60MW_i) \geq 700$ (3.1)
- $\sum_{i\in\{2,3,4\}}(GenMW_i + Res10MW_i + Res30MW_i + Res60MW_i) \geq 480$ (3.2)

Table A-14 shows the offer prices for minimum generation, incremental energy, and various reserve products for the five generators. The table also assumes that 100 MW of virtual supply (shown as V1) is placed in the Load Pocket, which only provide energy and do not count toward satisfying reserve requirements.

Table A-14: Generator Bids

Area	Generator	Min Gen	Inc Energy	10-Min Spin	10-Min Non-Spin	30-Min Reserve	60-Min Reserve
A	**G0**	\$19	\$19	\$1		\$0.5	
B	**V1**		\$18				
	G1	\$40	\$30	\$4.5		\$3	\$2
	G2	\$25	\$23	\$4.75		\$4	\$3.75
	G3	\$24	\$22	\$5		\$3.5	\$3
	G4		\$40		\$5		

Simulated Results Under the Dynamic Reserve Construct

Assuming a lossless system, the optimization produces the following scheduling and pricing outcomes (for energy, 10-minute spinning reserves, 10-minute non-spin reserves, 30-minute operating reserves, and 60-minute reserves) in Table A-15:

Table A-15: Scheduling and Pricing Outcomes with Dynamic Reserve Constraints

Area	Generator	Schedules (MW)					Prices ($/MWh)				
		Energy	10 SP	10 NS	30 OP	60 OP	Energy	10 SP	10 NS	30 OP	60 OP
A	G0	2100	180		210		$19	$1	$1	$0.5	$0
B	V1	100					$19				
	G1	75	0		55	90	$21.5	$3.5	$3.5	$3	$2.5
	G2	125	50		35	0	$23	$5	$5	$4.5	$4
	G3	200	0		0	0	$23	$5	$5	$4.5	$4
	G4	0		70			$23	$5	$5	$4.5	$4

These pricing outcomes are derived from the following binding constraints:

- Power balance constraint, with a shadow cost of $19/MWh;
- Systemwide 10-minute total reserve requirement, with a shadow cost of $0.5/MWh;
- Systemwide 30-minute total reserve requirement, with a shadow cost of $0.5/MWh;
- The constraint (3.1), with a shadow cost of $2.5/MWh; and
- The constraint (3.2), with a shadow cost of $1.5/MWh;

Accordingly, we have the following adders for energy and reserves for generators in the Load Pocket, as defined earlier,

- $Reserve\ Price\ Adder_{10min} = \begin{cases} SP_{1.1} + SP_{1.2} + SP_{2.1} + SP_{2.2} + SP_{3.1} + SP_{3.2} = \$\mathbf{4}, & i \in \{2,3,4\} \\ SP_{1.1} + SP_{2.1} + SP_{3.1} = \$\mathbf{2.5}, & i = 1 \end{cases}$
- $Reserve\ Price\ Adder_{30min} = \begin{cases} SP_{2.1} + SP_{2.2} + SP_{3.1} + SP_{3.2} = \$\mathbf{4}, & i \in \{2,3,4\} \\ SP_{2.1} + SP_{3.1} = \$\mathbf{2.5}, & i = 1 \end{cases}$
- $Reserve\ Price\ Adder_{60min} = \begin{cases} SP_{3.1} + SP_{3.2} = \$\mathbf{4}, & i \in \{2,3,4\} \\ SP_{3.1} = \$\mathbf{2.5}, & i = 1 \end{cases}$
- $LBMP\ Adder = \begin{cases} SP_{1.1} + SP_{1.2} + SP_{2.1} + SP_{2.2} + SP_{3.1} + SP_{3.2} = \$\mathbf{4}, & i \in \{2,3,4\} \\ SP_{1.1} + SP_{2.1} + SP_{3.1} = \$\mathbf{2.5}, & i = 1 \end{cases}$

Simulated Results Under the Current Market Construct

To illustrate the difference in scheduling and pricing between the dynamic reserve construct and current market construct, we also simulated this example system using the current market construct that:

- Commits the resources based on the N-1-1-0 requirement in the load pocket; then
- Dispatches and prices resources without explicitly modeling this requirement.

Keeping the same unit commitment but removing the dynamic reserve constraints (1.1)-(3.2), Table A-16 shows the scheduling and pricing outcomes under the current market construct.

Table A-16: Scheduling and Pricing Outcomes without Dynamic Reserve Constraints

Area	Generator	Schedules (MW)					Prices ($/MWh)				
		Energy	10 SP	10 NS	30 OP	60 OP	Energy	10 SP	10 NS	30 OP	60 OP
A	**G0**	2180	300		300		$19	$1	$1	$0.5	
B	**V1**	100					$19				
	G1	75	0		0	0	$19	$1	$1	$0.5	
	G2	125	0		0	0	$19	$1	$1	$0.5	
	G3	120	0		0	0	$19	$1	$1	$0.5	
	G4	0		0			$19	$1	$1	$0.5	

Unlike under the dynamic reserve construct, generators in the load pocket are all dispatched at their MinGen levels and have no reserve schedules under the current market construct. The pricing outcomes are derived from the following binding constraints:

- Power balance constraint, with a shadow cost of $19/MWh;
- Systemwide 10-minute total reserve requirement, with a shadow cost of $0.5/MWh;
- Systemwide 30-minute total reserve requirement, with a shadow cost of $0.5/MWh.

Discussion of Simulation Results

These simulation results demonstrate that, under the dynamic reserve construct,

- The market may schedule more expensive generators to provide energy inside the load pocket (e.g., G3 from 120 to 200 MW) and schedule less from inexpensive generation outside the load pocket (e.g., G0 from 2180 to 2100 MW) to hold reserves on the interface for the load pocket when it is economic to do so.
- Absent transmission congestion (no congestion in this example), price separation still exists between generators outside and inside the load pocket. Higher LBMPs in the load pocket ($21.5 - $23/MWh in the pocket vs. $19/MWh outside of the pocket) reflect additional values for satisfying local reliability needs.
- Energy prices for virtual supply may be lower than energy prices for physical supply in the load pocket ($19/MWh vs. $21.5-$23/MWh) as virtual supply only provides energy and does not satisfy local reliability needs.

- Energy and reserves prices for the largest generator in the load pocket may be lower than other generators in the load pocket ($21.5/MWh vs $23/MWh) because it is less valuable to satisfy local reliability needs as it is part of contingencies for deriving the reserve needs. However, instead of paying the largest unit different prices, an alternative way is to pay the largest unit the same prices (as for other units in the load pocket), but add a charge for extra reserve costs incurred because of the generation contingency. The extra reserve cost is calculated as the sum of shadow costs of constraint (1.2), (2.2) and (3.2) times the additional schedules on the largest generator (i.e., energy and reserve schedules of the largest generator Minus energy and reserve schedules of the second largest generator). In this example, the extra reserve cost is $1.5*(220-210) = $15.

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.[380] 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.[381]

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.[382] The amount of UCAP purchased is determined by the intersection of UCAP supply offers in the spot auction and the demand curve (adjusted for capacity sales through bilateral contracts and forward auctions).

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380 The ICAP requirement = (1 + IRM) * Forecasted Peak Load. The IRM was set at 18.9 percent in the most recent Capability Year (i.e., the period from May 2020 to April 2021). NYSRC's annual IRM reports may be found at "http://www.nysrc.org/NYSRC_NYCA_ICR_Reports.html".

381 The locational ICAP requirement = LCR * Forecasted Peak Load for the location. The Long Island LCR was 104.1 percent from May 2019 to April 2020 and 103.4 percent from May 2020 to April 2021. The New York City LCR was 82.8 percent from May 2019 to April 2020 and 86.6 percent from May 2020 to April 2021. The LCR for the G-J Locality was set at 92.3 percent from May 2019 to April 2020 and 90.0 percent from May 2020 to April 2021. 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 here.

382 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.

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:[383]

- 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.[384] 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);
- Analyses of the efficiency of the capacity market design, including the correlation of monthly spot prices with reliability value over the year (sub-section F) and zonal spot prices with reliability value in each region (sub-section G); and

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383 The demand curves also have maximum price levels which apply when UCAP procured falls substantially below the UCAP requirement. The demand curves for the 2019/2020 and 2020/2021 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 here.

384 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".

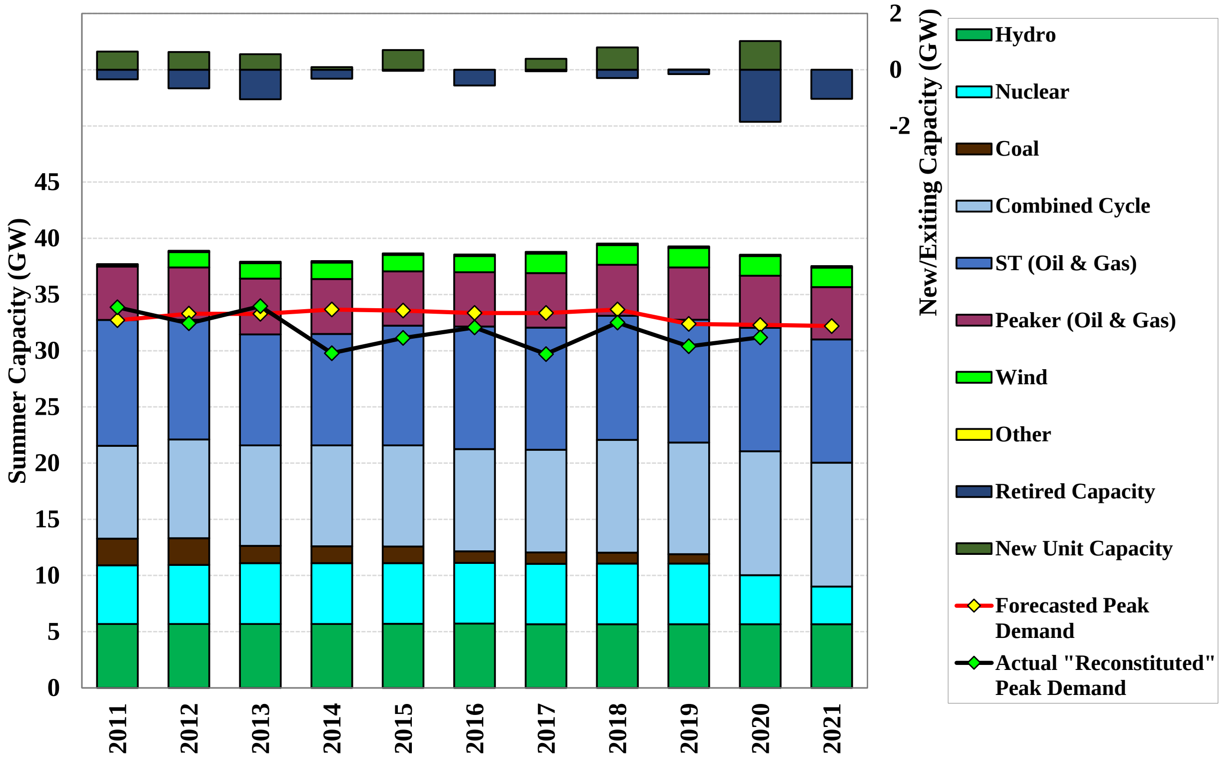
- The need for Financial Capacity Transfer Rights ("FCTRs") to incentivize merchant transmission projects (sub-section H).

A. Installed Capacity of Generators in NYCA

Figure A-105 - Figure A-106: Installed Summer Capacity and Forecasted Peak Demand

The bottom panel of Figure A-105 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 2011 through 2021.[385, 386] The top panel of Figure A-105 shows the amount of capacity that entered or exited the market during each year.[387]

Figure A-105: Installed Summer Capacity of Generation by Prime Mover
2011 – 2021



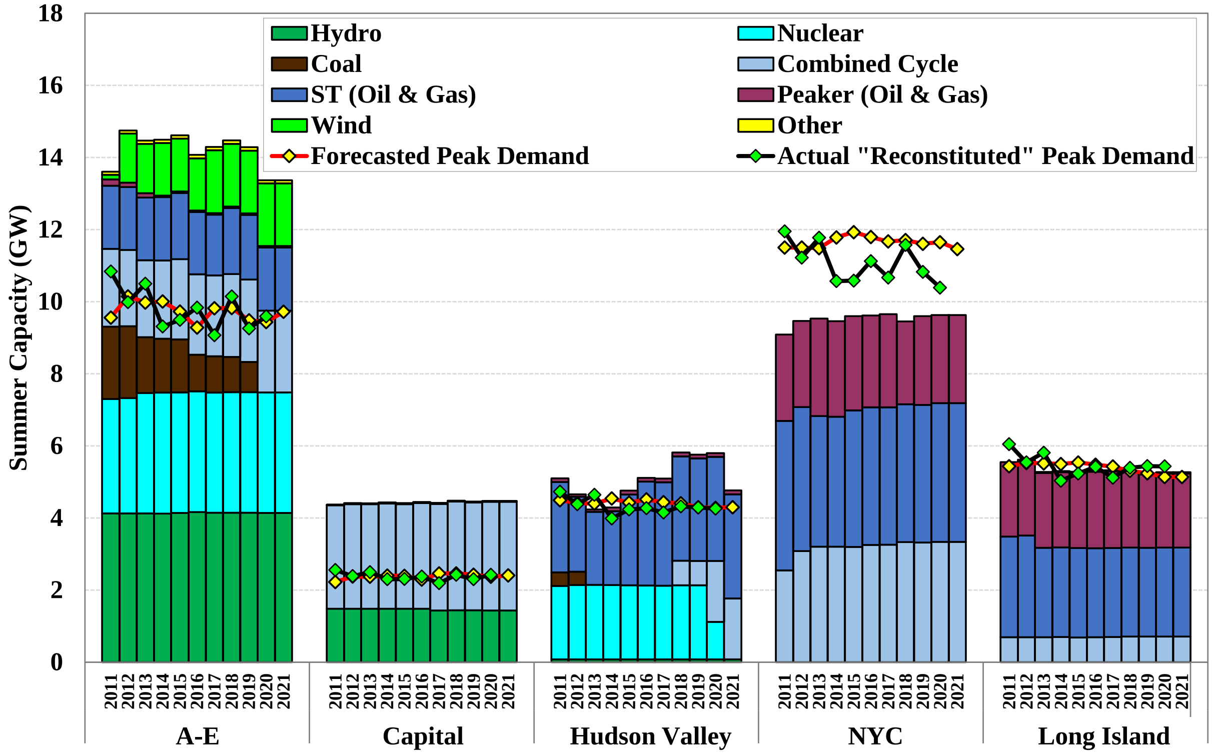
385 Forecasted peak demand shown is based on the forecasted NYCA coincident peak demand from the Gold Book of each year. Capacity is based on the Gold Book and Generator Status Update files available here.

386 In this report, we have reconstituted the historic coincident and non-coincident peak demand values in both Figure A-105 and Figure A-106 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.

387 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-106 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-106: Installed Summer Capacity of Generation by Region and by Prime Mover
2011 – 2021



<u>**Key Observations: Installed Capacity in NYISO**</u>

- The total generating capacity in the NYISO fell by about 2 percent (roughly 740 MW) in 2020 from the prior year but remained consistent with typical levels observed during the past decade. Historic summer capacity has ranged from 37.7 to 39.5 GW.
    - Despite the consistency in total capacity over time, more than 5 GW of capacity has exited the market since 2011 through a combination of retirements, mothballs, and ICAP Ineligible Forced Outages ("IIFO"). In the same timeframe, roughly the same amount of capacity has entered the market as new resources or as units returning from a mothball status.
        - Nearly 2 GW of this capacity exited the market in 2019 and 2020 as Indian Point 2, Kintigh (Somerset) and Milliken 1 (Cayuga) units retired or entered into a IIFO, and
- 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 3 GW between 2010 and 2020, with approximately 1.7 GW entering Hudson Valley between 2018 and 2020 at the CPV Valley and Cricket Valley plants. Other significant unit additions include the Empire (Capital zone) and Astoria Energy II (New York City) facilities.
- In addition, some new investment has also occurred in the form of dual-fuel peaking resources (for instance, the Bayonne I and II projects interconnecting with New York City). However, the total peaking capacity in the state has decreased slightly (100 MW) from 2011 to 2020 because the exit of older, less-fuel-efficient peakers (such as several Ravenswood GTs) has outpaced entry of newer, more-efficient resources.

- 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.[388]
  - In addition, the State has also initiated procurements that could result in the addition of several GW of battery storage and offshore wind over the next decade.

- On the other hand, a combination of low gas prices and stronger environmental regulations are leading to the retirement of significant amounts of capacity from coal-fired generation, nuclear generation, and old gas turbine facilities in New York.
  - All the capacity from coal units (nearly 3 GW of in 2009) has exited the market by the Summer of 2020.[389]
  - 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 April 2020 and the other in April 2021.
  - The DEC peaker rule will require large additional expenditures for GTs to continue operations and so it will likely result in retirement of many units in downstate areas. Indeed, a number of resource owners have indicated their intention to retire these facilities as part of the compliance plans filed with the DEC.
  - Other notable retirements in the last decade include several dual-fueled steam units such as Astoria 4 in NYC in 2012 and the Glenwood 04 and 05 units in Long Island in 2012.

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388 See Section 0.C of the Appendix for the contribution of federal and state incentives to the net revenues of renewable units in New York.

389 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.

- Since at least 2011, the capacity mix in New York has been predominantly gas and oil resources (63 to 65 percent) while the remainder is primarily hydro and nuclear (each 14 percent).
    - With the retirement of Indian Point units and the entry of Cricket Valley in 2020, this balance has shifted further towards gas and oil resources (71 percent) and away from nuclear (nine percent).
- As shown in Figure A-106, 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 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 have been considerably larger new investments in non-wind resources in the eastern zones where capacity prices tend to be higher.

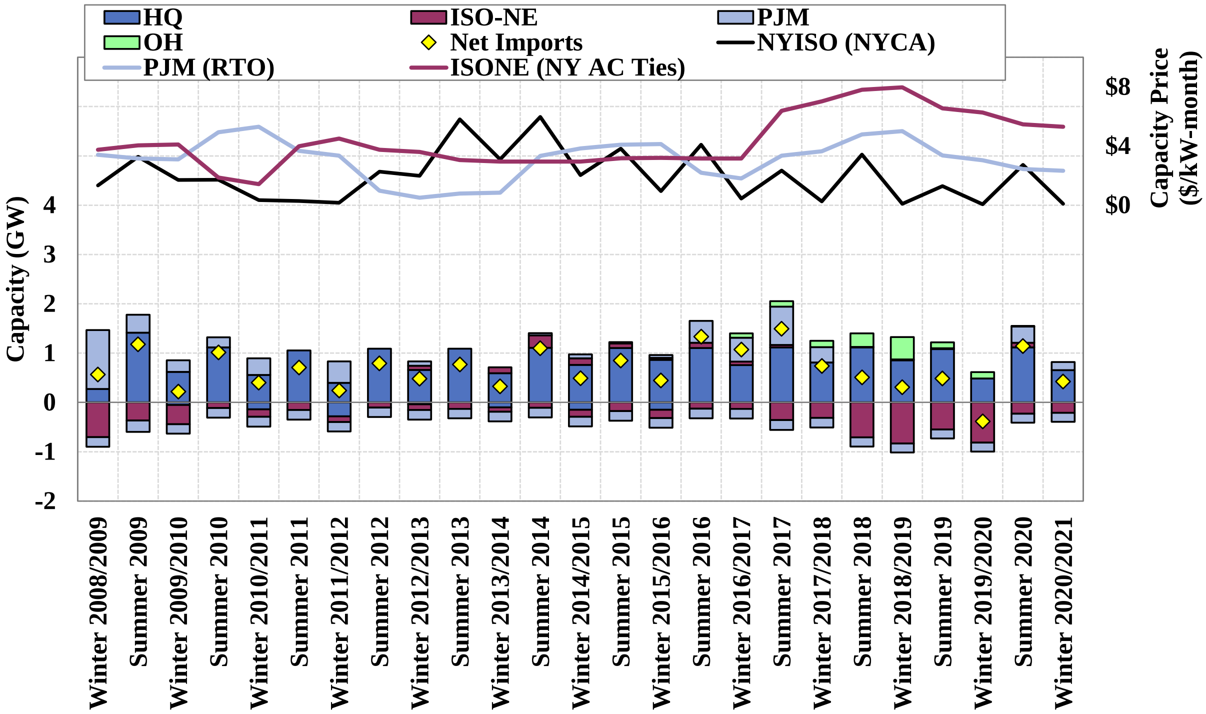
B. Capacity Imports and Exports

Figure A-107: NYISO Capacity Imports and Exports by Interface

Figure A-107 shows the monthly average of net capacity imports into the NYISO from neighboring control areas from Winter 2007/08 through Winter 2020/21 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.[390] 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.

390 The values for Winter 2020/21, reflect average net imports and average prices through January 2021.

Figure A-107: NYISO Capacity Imports and Exports by Interface
Winter 2008/09– Winter 2020/21



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 its 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 always 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.[391]
  - 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

391 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 followed FERC's decision supporting the measures in 126 FERC 61,046 (January 15, 2009). For more information, see here.

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 0 MW in the 2019/2020 Capability Year. An average of 320 MW of capacity from PJM was imported in Summer 2020 as the NYCA prices increased in response to the exit of several large units.[392, 393]

- Capacity exports to ISO-NE increased significantly in recent years, with 600 MW to 850 MW sold over the NY-NE AC Ties during the 2018/19 and 2019/20 Capability Years. 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. However, imports to ISO-NE fell to around 210 MW to 230 MW during the most recent capability year as the capacity prices in ISO-NE declined relative to 2019/20.

- 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 tracked closely to the value of the ICAP import rights.[394]

  - The Summer 2020 Capability Period saw an average of just 20 MW of 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.[395]

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 and an EFORd of 7 percent would be able to sell 93 MW of UCAP.[396] This gives suppliers a strong incentive to perform reliably.

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392 The changes to requirements of external capacity suppliers are outlined in §4.9.3 of the NYISO ICAP Manual. See here.

393 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.

394 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.

395 See External Rights Availability by interface and by Capability Period here.

396 The variables and methodology used to calculate EFORd for a resource can be found here.

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.[397]

Table A-17: Historic Derating Factors by Locality

Table A-17 shows the Derating Factors the NYISO calculated for each capacity zone from Summer 2016 onwards.

Table A-17: Derating Factors by Locality

Summer 2016 – Winter 2020/21

Locality	Summer 2020	Summer 2019	Summer 2018	Summer 2017	Summer 2016	Winter 2020/21	Winter 2019/20	Winter 2018/19	Winter 2017/18	Winter 2016/17
G-I	5.77%	7.15%	4.92%	12.70%	5.00%	3.21%	6.87%	6.45%	11.72%	6.46%
LI	6.91%	6.47%	6.28%	5.60%	7.27%	5.91%	7.96%	6.90%	6.07%	6.36%
NYC	3.51%	4.09%	7.09%	4.37%	9.53%	2.70%	4.42%	5.98%	5.26%	5.44%
A-F	11.78%	12.50%	11.15%	11.94%	11.61%	9.63%	10.26%	8.93%	9.83%	8.64%
NYCA	8.30%	8.79%	8.56%	9.29%	9.61%	6.61%	8.00%	7.57%	8.43%	7.25%

<u>Key Observations: Equivalent Forced Outage Rates</u>

- The NYCA-wide Derating Factor decreased (i.e., improved) from Summer 2019 to Summer 2020 (by 0.49 percentage points) and from Winter 2019/20 to the Winter 2020/21 Capability Period (by 1.39 percentage points).
    - The change in NYCA-wide summer and winter Derating Factors can largely be attributed to improved EFORd ratings of certain large steam and combined cycle units, which outweighed year-over-year EFORd increases of small peaking units.
- The Derating Factor for Zones A-F is generally higher than observed in other zones.
    - As shown in Figure A-106, 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.
    - As more intermittent or run-hour limited resources are potentially added to the system in the coming years, it is likely that the Derating Factors in all regions would rise as a consequence.
- The New York City Derating Factor is prone to considerable swings from one year to the next based on the performance of its old generation fleet. Although over 3 GW of relatively new gas-fired capacity is interconnected in this zone, it also contains several

397 The Derating Factor used in each six-month capability period for each Locality may be found <u>here</u>.

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.

- The marked decrease in New York City Derating Factor in the 2020/21 Capability Year was largely driven by the EFORd calculation of several steam units, which rolled-off large outages.
- Additionally, the past couple of years have seen low load levels and relatively few hours where certain older, less-reliable generators have had to produce energy. With fewer run hours, the impact of an outage is much larger on the EFORd calculation and can result in more significant swings in the value for any one unit.

Figure A-108: Gas and Oil-Fired EFORds by Technology Type and Region

Figure A-108 presents the distribution of EFORds of natural gas and oil-fired units based on technology type and age designation.[398] 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.

398 The age classification is based on the age of the plant. Units that are older than 20 year are tagged as "OLD" while units less than or equal to 20 years are marked as "NEW."

Figure A-108: EFORd of Gas and Oil-fired Generation by Age
Summer – Five-Year Average

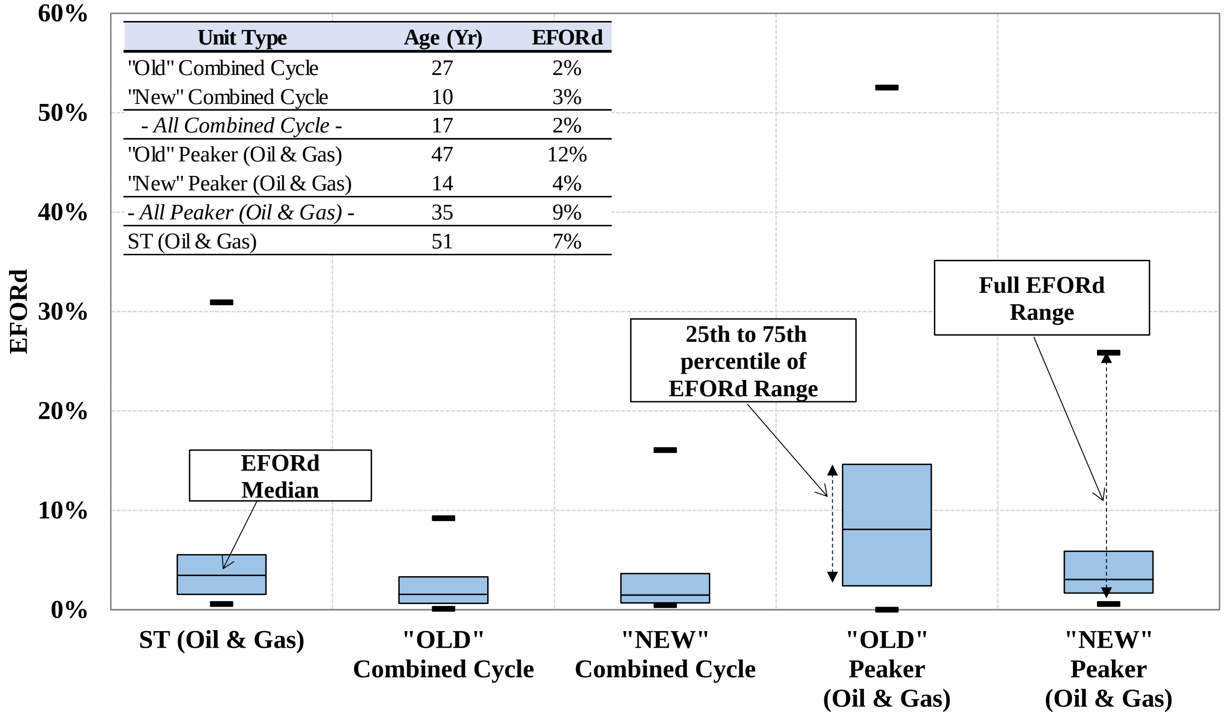

Table A-18: Illustrative EFORd Calculations for Service Hours Impact on Rating

Table A-18 provides illustrative representations of EFORd values for various technologies according to calculations consistent with data submitted in NERC GADS reporting process.[399] This information is meant to provide context to two scenarios:

- First, it highlights the impact of service hours on EFORd values to emphasize the discrepancy that may arise between long run time units, such as a steam turbine, and short run time units, such as a peaking unit, that may be similar in most regards but give a more favorable EFORd to the longer run time unit. This information is shown under the columns titled "Current Approach – All Hours; No seasonality."

- Secondly, additional columns are provided to show the likely impacts of a more tailored EFORd value using the same calculation but with the service hours and outage hours weighted to a 6-hour daily peak during peak seasonal months. This information is shown under the columns "Tailored Approach – 6-Hour peak; Seasonality."

Data in this table is given for three hypothetical units under the two approaches outlined above. They all have the same likelihood of experiencing a forced outage on start-up (16.7 percent), but the units differ in the number of hours they run per successful start:

399 Additional background on GADS can be found here.

- **Steam Unit – Short Run Time:** This is a steam unit that is expected to operate for one day per start.

- **Steam Unit – Long Run Time:** This is a steam unit that is expected to operate for one week per start.

- **Peaking Unit:** This is a peaking unit that is expected to operate for 1.5 hours per start during peak hours only.

In order to most simply compare the impacts of service hours on the resultant EFORd values for each resource type given, each of the two approaches assumes that the total number of outages, the duration of each outage, and the total number of successful starts between the three units are equivalent. Additionally, we maintain the same ratio of forced outages to successful starts between both scenarios, which is reasonable given that the most likely time for a unit to experience a forced outage is during the start-up cycle. However, we assume that the service hours per successful start differ among the three units according to the durations listed above. This illustrates: (a) how some generators have incentives to increase service hours in order to reduce EFORd ratings, and (b) how this incentive is reduced by a more tailored approach to which hours have the greatest reliability impact.

Table A-18: Illustrative EFORd Calculations for Service Hours Impact on Ratings

Assumptions	Calcs	Current Approach			Tailored Approach		
		Peaking Unit	Steam Unit - Short Run Time	Steam Unit - Long Run Time	Peaking Unit	Steam Unit - Short Run Time	Steam Unit - Long Run Time
# of attempted starts	*(1)+(2)*	24	24	24	6	6	6
# of of successful starts	*(1)*	20	20	20	5	5	5
# of forced outages	*(2)*	4	4	4	1	1	1
Service Hours	*(3)*	30	480	3360	7.5	30	210
Full Forced Outage Hours	*(4)*	24	48	48	6	6	6
Days per Forced Outage	*Current = (4)/(2)/24* *Tailored = (4)/(2)/6*	0.25	0.50	0.50	1.00	1.00	1.00
Operating Days per Start	*Current = (3)/(1)/24* *Tailored = (3)/(1)/6*	0.06	1.00	7.00	0.25	1.00	7.00
- EFORd -		13.7%	7.1%	2.1%	13.8%	10.4%	3.9%

Key Observations: EFORd of Gas and Oil Units

- As shown in Figure A-108, 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 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.
- The current approach for calculating EFORd values likely overvalues the impact of service hours resulting in lower EFORds for older, less reliable steam units.
    - For example, while the steam unit and peaking unit have a 16.7 percent chance of a forced outage on start-up, the steam unit that operates for 24-hours at a time has an EFORd of 7.1 percent while the peaking unit has an EFORd of 13.7 percent. The steam unit receives a lower EFORd by running outside the six-hour peak window even though this provides little additional reliability value, which may lead to an under-estimate of its likelihood of having a forced outage.
    - In a similar way, the steam unit that runs for one day per start has a higher EFORd than a steam unit that runs for one week per start. This leads the daily-cycle steam unit to have an EFORd of 7.1 percent, while the weekly-cycle steam unit has an EFORd of 2.1 percent. The weekly-cycle steam unit receives a lower EFORd than a daily-cycle steam unit by running for multiple days per start, which provides significant additional reliability value, since the most extreme weather generally persists for multiple consecutive days.
- An approach to calculating the EFORd values of units in the market based on performance during specific peak load hours and months would likely reduce the advantage of units with longer run times relative to the shorter run time generators to some degree, especially in the case of large, slow ramping units that run seldomly and for occasional peak load days.
    - Our estimates indicate that the effective increase in EFORd values would be minimal to peaking units when hours are weighted based on this approach. However, longer run time units that benefit from reliable performance during off-peak hours steam

units would expect increased EFORd values when holding the number of successful starts and outages consistent between the three unit types.

- Under the tailored approach, the peaking unit in our hypothetical example would receive an EFORd increase of only 0.1 percent.[400]
- Under the tailored approach, the steam unit running for one day per start would receive an increase in EFORd ratings of 3.3 percent, while the steam unit running for one week per start would receive an increase in EFORd of 1.8 percent.
- This tailored approach would maintain some of the benefit that is appropriate for the long-run steam unit over the other two units, which is consistent with the increased likelihood of operating across more peak load hours during the year.

D. Capacity Market Results: NYCA

Figure A-109: Capacity Sales and Prices in NYCA

Figure A-109 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.[401] The hollow portion of each bar represents the In-State capacity in each region not sold (including capacity not offered) in New York or in any adjacent market. The line indicates the capacity requirement for each Capability Period for NYCA. Additionally, Figure A-109 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-109 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-109 also shows the forecasted peak load and the ICAP requirements.

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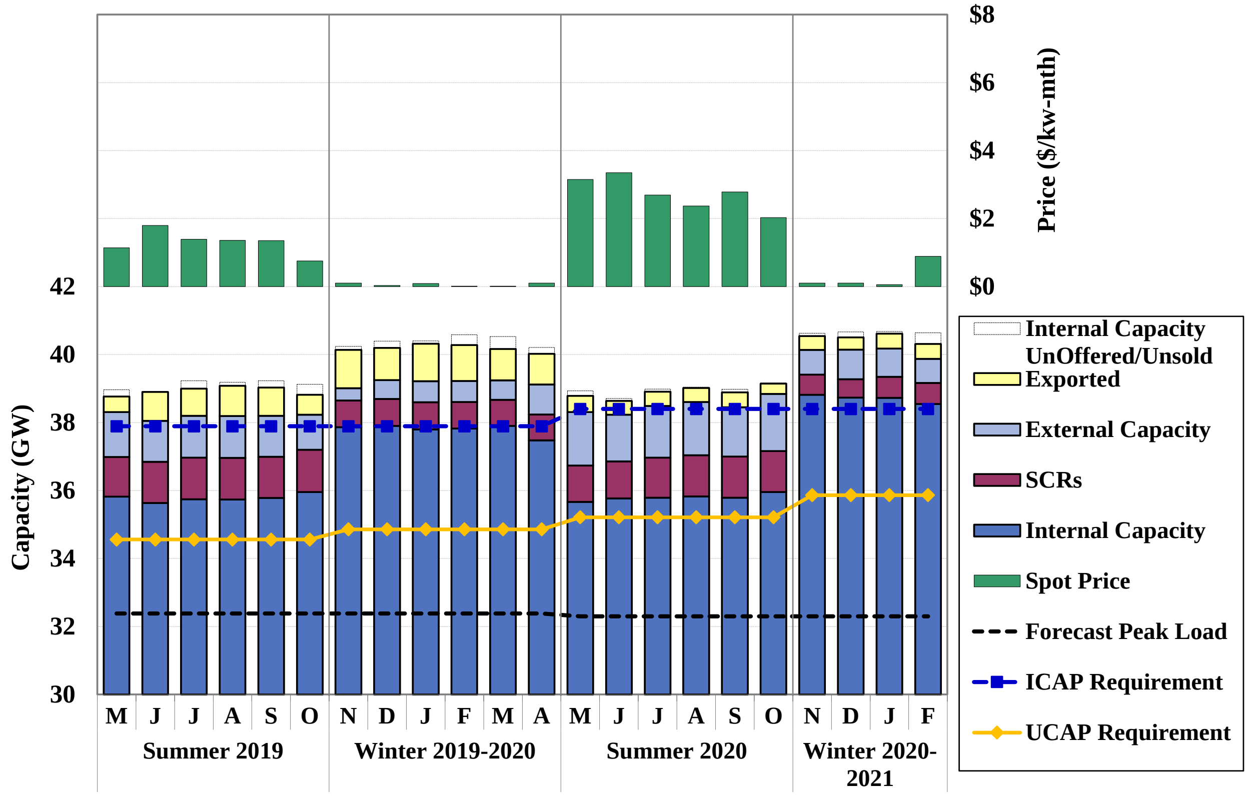
400 The impact for a peaking unit is mitigated by the assumption that the starts and operating hours of a peaker would be heavily weighted towards the peak hours.

401 Special Case Resources ("SCRs") are Demand Side Resources whose Load is capable of being interrupted upon demand, and/or Demand Side Resources that have a Local Generator, which is not visible to the ISO's Market Information System and is rated 100 kW or higher, that can be operated to reduce Load from the NYS Transmission System and/or the distribution system at the direction of the NYISO.

Figure A-109: UCAP Sales and Prices in NYCA
May 2019 to February 2021



Key Observations: UCAP Sales and Prices in New York

- Seasonal variations drive significant changes in clearing prices in spot auctions between Winter and Summer Capability Periods.
  - Additional capability is typically available in the Winter Capability Periods due to lower ambient temperatures, which increase the capability of some resources to produce electricity. This contributes to significantly lower prices in the winter than in the summer.
  - Capacity imports from Quebec typically fall in the coldest winter months (i.e., December through March), since Quebec is a winter peaking region. This reduction partially offsets the increased ambient availability of internal generators during these months.
- UCAP spot prices rose sharply in Rest of State in the 2020/21 Capability Year from the prior year. The spot price averaged $2.73/kW-month in the Summer 2020 Capability Period, which was 110 percent higher than the prior summer, and $0.29/kW-month in the 2020/21 Winter Capability Period, which was up 400 percent from the prior winter.
  - Prior to the February Spot Auction, the winter price had averaged $0.09 per kW-month this year. Beginning in February, prices rose to $0.89 per kW-month largely due to higher offer prices from specific supplier(s). Typically, capacity suppliers act

as price-takers in the spot auction, but given the persistent near-zero prices over the past two winters, some suppliers have begun to offer at higher price levels. Notwithstanding, spot capacity prices remain quite low relative to the cost of entry.

- A key driver of the year-over-year price increase was the rise in the ICAP requirement of 512 MW from the prior Capability Year. This was because of the increase in IRM by 1.9 percentage points in 2020/21.
  - However, the peak demand forecast for the NYCA fell by nearly 90 MW from the prior year, which offset some of the increase in IRM.
- During the 2020 Summer, the total imports from external control areas rose by an average of 320 MW, with exports from NYCA to neighboring regions concurrently falling by an average of 320 MW. The resultant 640 MW increase in net imports (i.e., the sum of the increase imports and the reduced exports) offset a large portion of the retired coal capacity.

- The UCAP Requirement rose by approximately 650 MW in the Summer Capability Period and 1 GW in the Winter Capability Period because of a higher IRM and the year-over-year improvement (i.e., reduction) in Derating Factors. [402]
  - In the short-term, spot capacity prices are affected most by the ICAP Requirement in each locality (as opposed to the UCAP Requirement), since variations in the Derating Factor closely track variations in the weighted-average EFORd values of resources.
  - However, in the long-term, higher Derating Factors tend to increase the IRM and the LCRs because the IRM and LCR Studies incorporate EFORd values on a five-year rolling average basis.

E. Capacity Market Results: Local Capacity Zones

Figure A-110 - Figure A-112: Capacity Sales and Prices in NYC, LI, and the G-J Locality

Figure A-110 to Figure A-112 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-109 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.

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402 ICAP Requirements are fixed for an entire Capability Year, so the same requirements were used in the 2020 Summer and 2020/21 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.

Figure A-110: UCAP Sales and Prices in New York City
May 2019 to February 2021

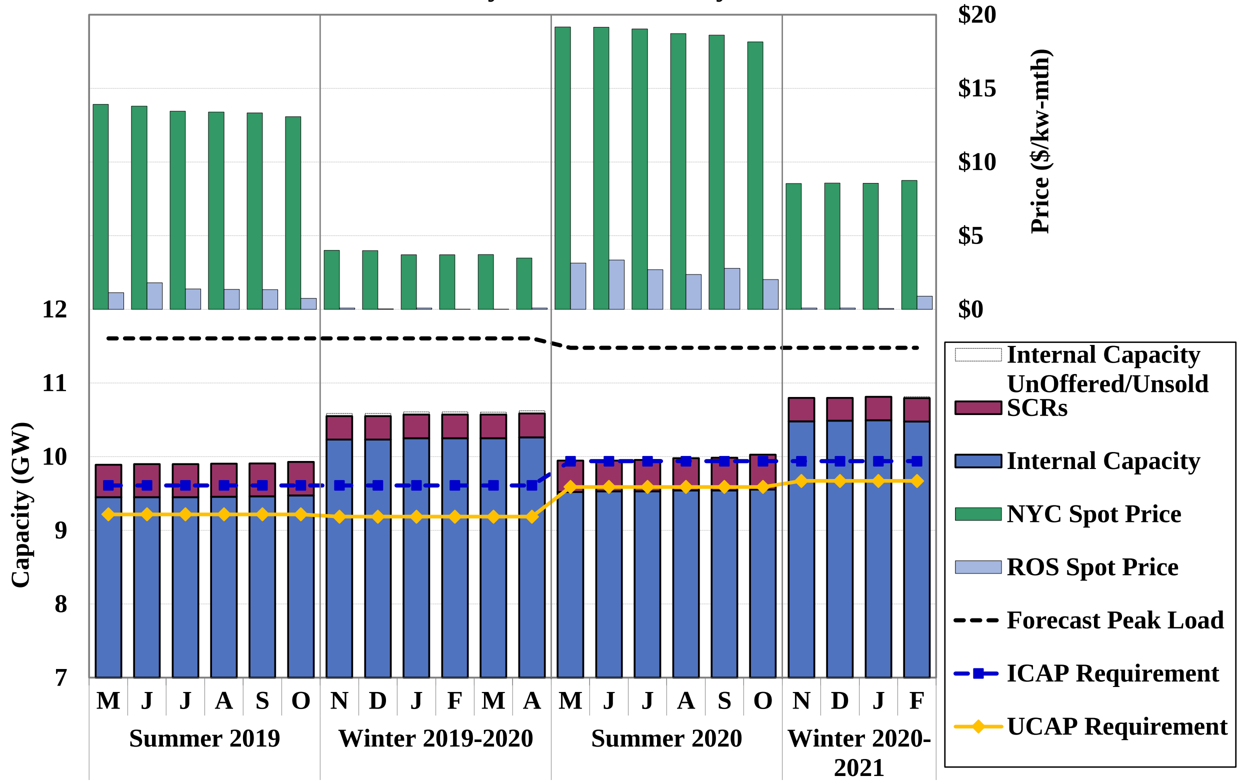


Figure A-111: UCAP Sales and Prices in Long Island
May 2019 to February 2021

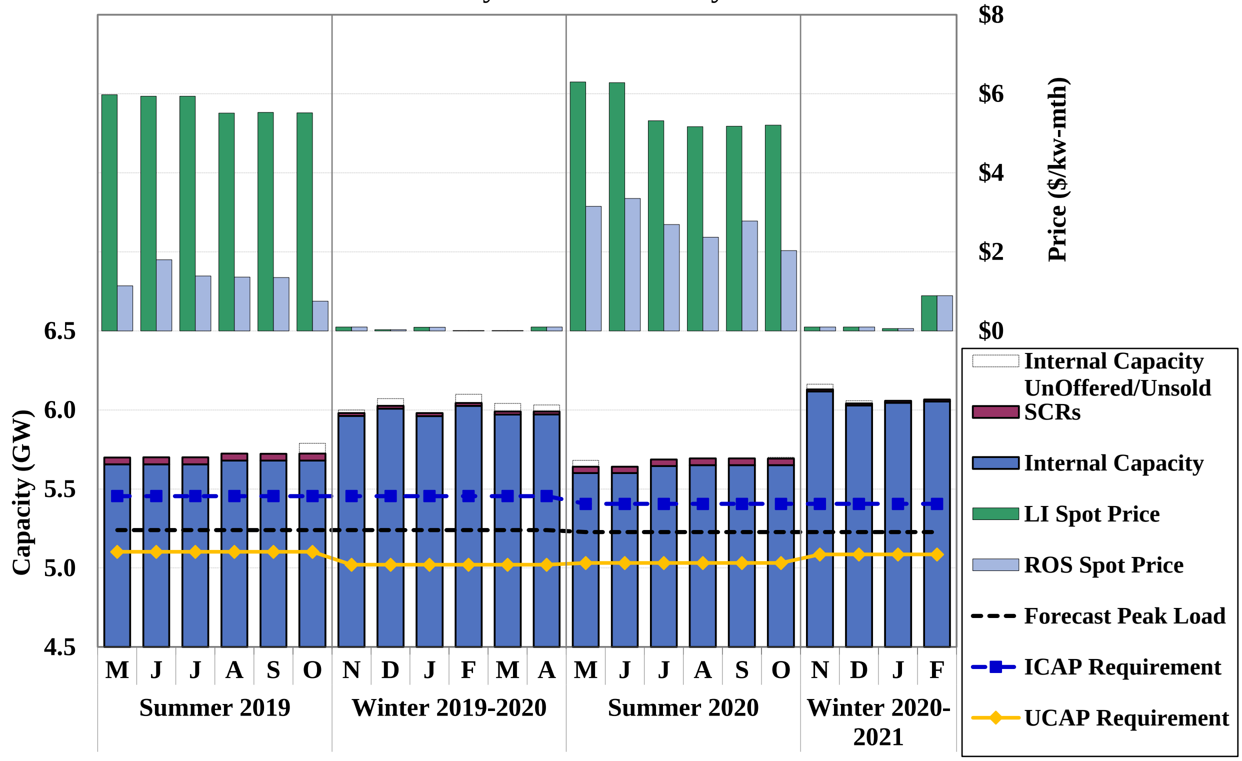
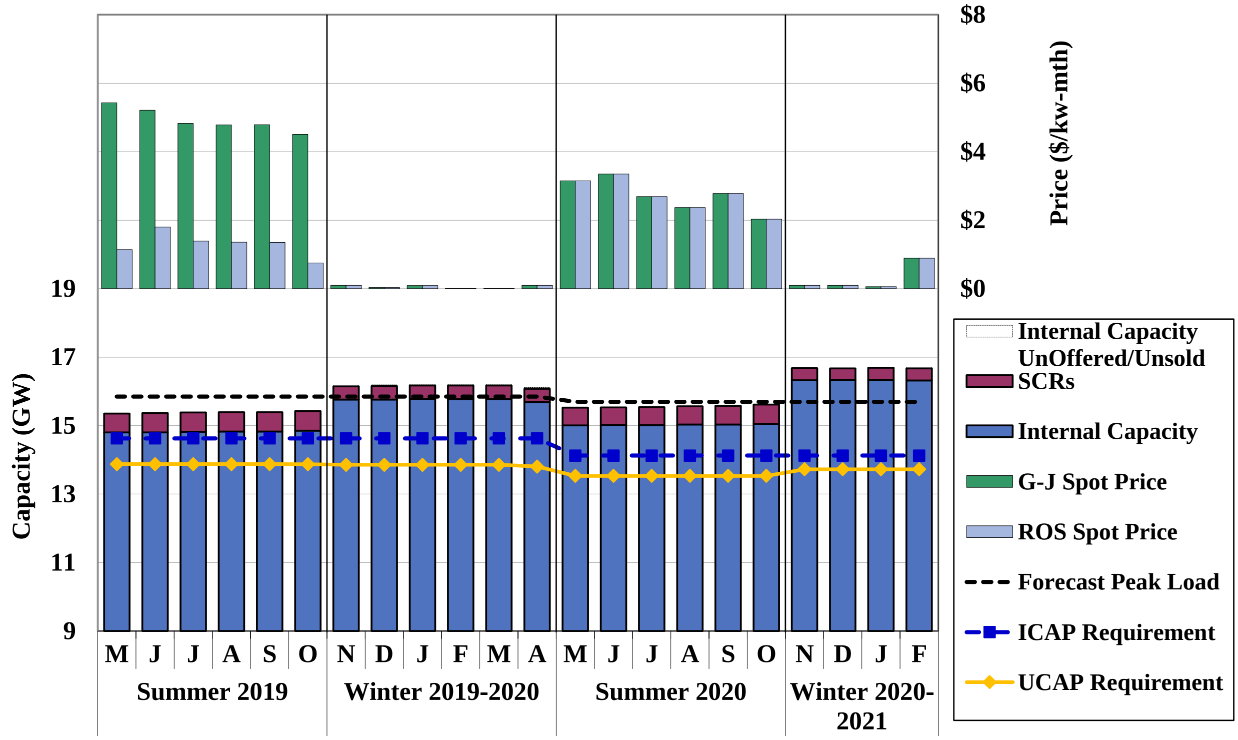


Figure A-112: UCAP Sales and Prices in the G-J Locality
May 2019 to February 2021



Key Observations: UCAP Sales and Prices in Local Capacity Zones

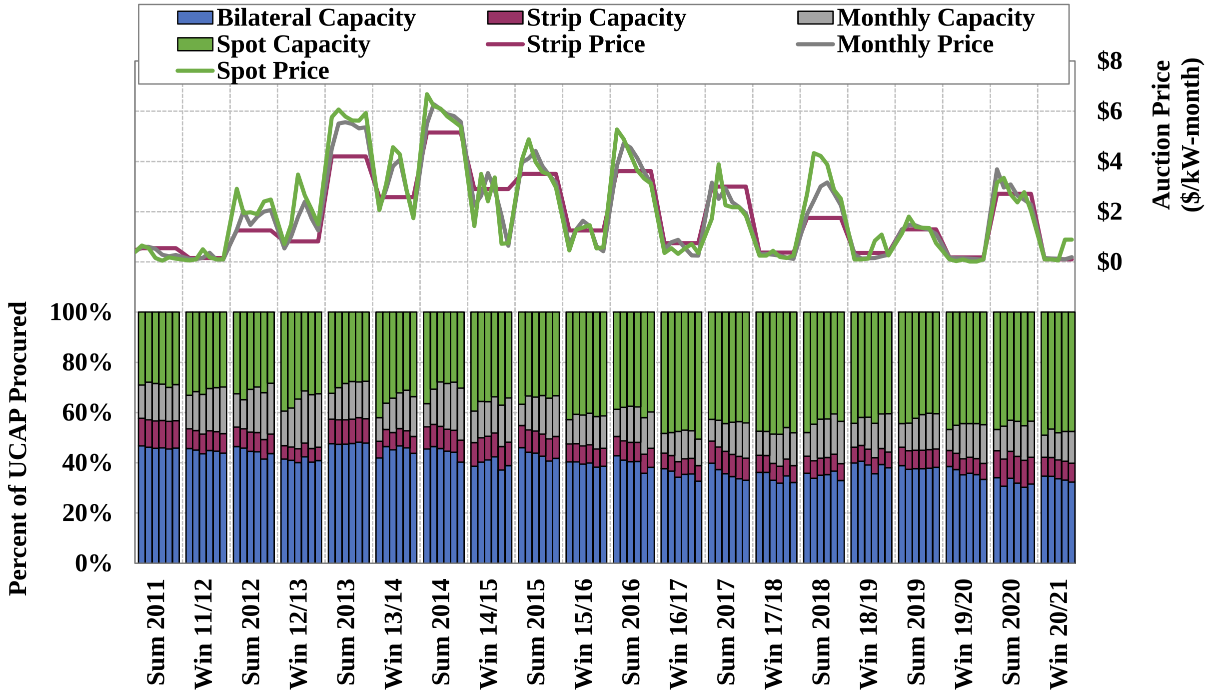
- As in the statewide market, seasonal variations substantially affect the market outcomes in the local capacity zones.
- The Summer and Winter UCAP spot prices changed substantially in the three eastern capacity zones during the 2019/20 Capability Year from the prior year. Specifically:
  - New York City spot prices rose: (a) 39 percent to an average of $18.81/kW-month in the 2020 Summer Capability Period; and (b) 123 percent to an average of $8.61/kW-month in the 2020/21 Winter Capability Period.
  - Long Island spot prices fell: (a) 3 percent to an average of $5.58/kW-month in the 2020 Summer Capability Period; and rose (b) 400 percent to an average of $0.29/kW-month in the 2020/21 Winter Capability Period.
  - The G-J Locality spot prices fell: (a) 45 percent to an average of $2.73/kW-month in the 2020 Summer Capability Period; and rose (b) 400 percent to an average of $0.29/kW-month in the 2020/21 Winter Capability Period.
- Spot auction prices rose in New York City due to a sharp increase in the LCR from 82.8 percent to 86.6 percent. However, the NYC peak demand forecast fell by roughly 130 MW.

- The spot prices fell in Long Island because the ICAP requirement declined as the LCR fell by 0.7 percent from 104.1 percent to 103.4 percent and the peak load forecast fell by 13 MW.
  - Summer prices would have been lower but for the lack of sales from a few small generators during May and June totaling approximately 40 MW in unsold capacity during those months.
  - Winter prices cleared on the NYCA curve since the surplus during this season exceeded the 18 percent value constituting the zero-crossing price on the LI demand curve.
- The annual average spot prices in the G-J Locality fell largely due to the decrease in LCR by 2.3 percentage points and the load forecast fell by roughly 150 MW. Consequently, the ICAP requirement in this region fell by 500 MW from the previous Capability Year.
  - Although the Indian Point 2 unit retired in 2020, the Cricket Valley Energy Center units commenced operation in 2020. These units have similar capacity ratings resulting in little change to the year-over-year supply totals for the Locality.
  - 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 during the Winter 2020/2021.
- Overall, very little capacity was unsold in the G-J Locality, New York City, and Long Island in 2020.

Figure A-113: Capacity Procurement by Type and Auction Price Differentials

Figure A-113 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 ten Capability Years. Bilateral prices are not reported to the NYISO and are not included in this figure. 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 2011 capability period on a dollar-per-kilowatt-month basis.

Figure A-113: Auction Procurement and Price Differentials in NYCA
May 2011 – February 2021



<u>Key Observations: Capacity Procurement and Price Comparison</u>

- Almost 80 percent of the total UCAP in NYCA is procured via bilateral transactions (32 percent in Summer 2020) or in the Spot market (45 percent in Summer 2020). The remaining capacity is procured through the Strip (11 percent in Summer 2020) and Monthly (13 percent in Summer 2020) auctions.
  - The proportions of capacity procured through the four different mechanisms has remained in a relatively narrow range historically, with the procurement in the spot market increasing slightly at the expense of the other three mechanisms.
  - Summer 2020 and Winter 2020/21 witnessed the lowest proportion of UCAP procured bilateral contracts, which was 6 percentage points lower than the average from Summer 2019, with increased participation in the Strip and Spot Auctions.

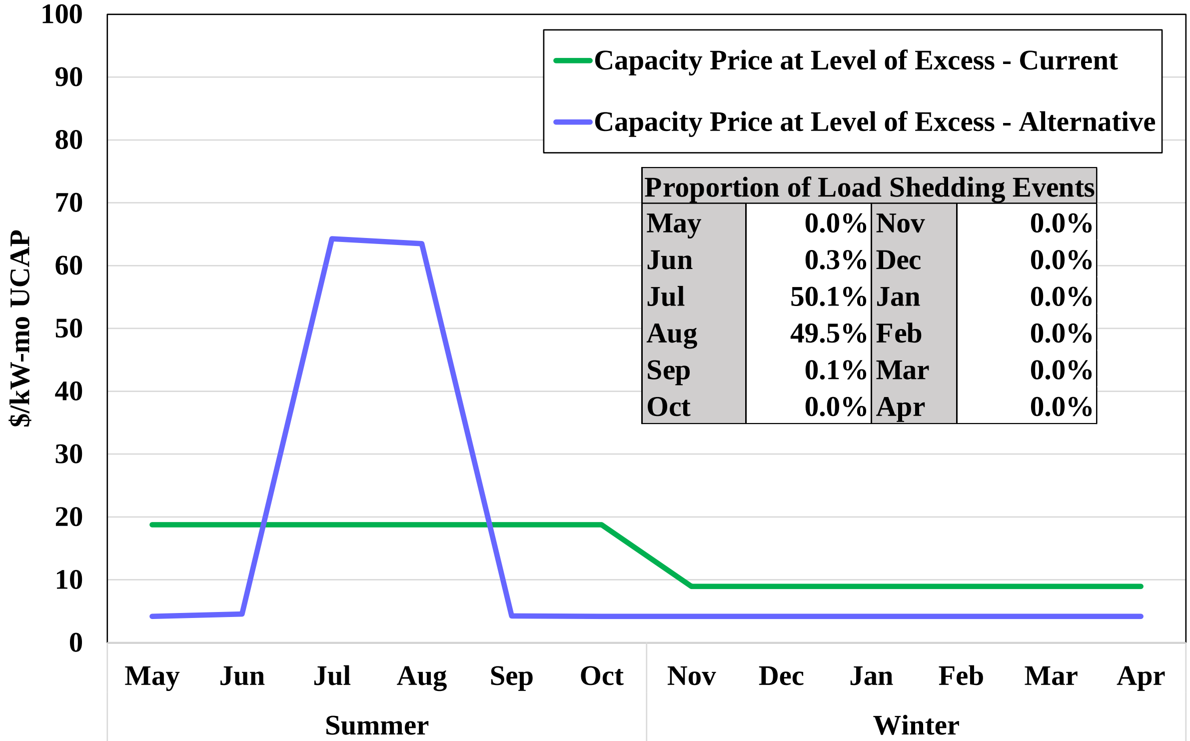
F. Translation of the Annual Revenue Requirement into Monthly Capacity Demand Curves

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 (in ICAP terms), 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 33: Monthly Capacity Clearing Prices Compared to Capacity Value

Figure 33 shows the clearing price (in green) 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 an alternative price (in blue) 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. The alternative price is subject to a minimum of monthly demand curve reference point value of $4/kW-month, to provide suppliers with incentives to coordinate outages through the NYISO outage scheduling process. The inset table shows the distribution of load shedding events by month in the 2020/21 IRM case of the NYISO's resource adequacy model.

Figure 33: Monthly Capacity Clearing Prices Compared to Capacity Value
At Level of Excess Conditions



<u>Key Observations: Monthly Capacity Pricing Alternative</u>

- The value of capacity is concentrated during a relatively small number of months. Under a capacity pricing structure reflecting the probability of load shed in each month, the majority of annual compensation would be awarded to resources available in the months of July and August.

- 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).

  - For example, owners of plants affected by the DEC Peaker Rule have indicated that over 350 MW of capacity will begin operating only outside of the ozone season by 2023 and over 1,100 MW by 2025.[403]

- We recommend the NYISO translate the annual revenue requirement into monthly capacity demand curves based on the following:[404]
  - 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 Capability Year.
- Overall, 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), which is consistent with when the likelihood of load shedding is the highest.

G. Cost of Reliability Improvement from Additional Capacity

An efficient capacity market would signal for capacity to locate where it is most cost-effective to improve system reliability. In this subsection, we discuss a framework for measuring capacity prices relative to this objective and evaluate the effectiveness of the NYISO market at meeting it.

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.

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403 See NYISO 2020 Gold Book Table IV-6. These totals reflect winter installed capacity.

404 See Recommendation #2019-4 in Section XII.

The NYISO's methodology for determining the LCRs beginning the 2019/2020 Capability Year ("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 per 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-19: Cost of Reliability Improvement

Table A-19 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 0.053 in the 2021/22 Capability Year.[405]

The table shows the following for each area:

- *Net CONE of Demand Curve Unit* – Based on the Net CONE curves filed by NYISO for the 2021/2022 Capability Year.[406]
- *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.[407]
- *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.

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[405] 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 350 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.

[406] NYISO filed proposed ICAP demand curves with FERC following its 2020 Demand Curve Reset process on November 30, 2020.

[407] These values were obtained by starting with the system at Excess Level with an LOLE of 0.0053 and calculating the change in LOLE from a 100-MW 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.[408, 409] This is calculated based on the ratio of the *Net CONE of Demand Curve Unit* to the *MRI* for each area.

Table A-19: Cost of Reliability Improvement
2021/22 Capability Year

Locality/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*
NYCA					
A	$82		0.048	0.0047	$1.7
B	$82		0.048	0.0050	$1.6
C	$82		0.050	0.0030	$2.7
D	$82		0.050	0.0030	$2.7
E	$82		0.050	0.0029	$2.8
F	$82		0.050	0.0030	$2.7
G-J Locality		0.053			
G	$115		0.049	0.0037	$3.1
H	$115		0.049	0.0039	$2.9
I	$115		0.049	0.0039	$2.9
NYC					
J	$163		0.046	0.0067	$2.4
Long Island					
K	$106		0.049	0.0038	$2.8

Key Observations: Cost of Reliability Improvement

- The Net CONE varies considerably across NYCA, ranging from $82/kW-year in Zones A to F to $163/kW-year in Zone J.

- The MRI of resources also varies widely across the system and generally falls into four groups, which are listed from lowest to highest:
  - Zones C to F – These resources have the lowest reliability value (~0.0030), reflecting that they are outside of import-constrained areas.
  - Zones G to I and K – These resources have higher reliability value (~0.0038), reflecting that they provide additional value when there are constraints into Southeast New York.

408 For example, for Zone F: $82/kW-year × 1000kW/MW ÷ (0.003 LOLE change/100MW) × 0.001 LOLE change = $2.7 million.

409 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.

  - Zones A and B – These resources have higher reliability value (~0.0050), reflecting that they provide additional value when there are constraints into Zones A and B.
  - Zone J – These resources have the highest reliability value (~0.0067), reflecting that they provide additional value when Zone J is import-constrained.

- The range between the minimum CRI-value location (Zone B at $1.6 million per 0.001 events) and the maximum CRI-value location (Zone G at $3.1 million per 0.001 events) is substantial.
  - Zone B exhibits the lowest CRI because it is assumed to have a low Net CONE ($82/kW-year) and relatively high MRI (0.0050 days per 100 MW).
  - Zone G exhibits the highest CRI because it is assumed to have a higher Net CONE ($115/kW-year) and relatively low MRI (0.0037 days per 100 MW).
- The wide variation in CRI values highlights that some areas have inefficiently high or low capacity requirements.
  - For example, the relatively low CRI in Zone J indicates that it would be efficient to place additional capacity there. This highlights that the LCR for the 2021/22 Capability Year for Zone J (of 80.3 percent) is below the efficient level.
- The CRI values for some zones exhibit considerable differences from those of other zones within the same capacity pricing region under the current configuration. This highlights transmission constraints within certain capacity regions.
  - Zones A and B have a lower CRI than zones C-F, reflecting transmission constraints (between zones B and C) that were not binding in previous years. This result is likely driven by at least two factors:
    - Interaction of Kintigh retirement with the Tan 45 procedure – The recent retirement of the large coal-fired Kintigh (or Somerset) unit significantly reduced the surplus capacity margin in Zone A. The statewide IRM is determined using the “Tan 45” procedure, which shifts capacity in and out of the upstate region in proportion to the capacity surpluses in Zones A, C, and D. Therefore, when the surplus in Zone A was reduced by the Kintigh retirement, it increased the amount of capacity that must be placed in Rest of State in order to relieve an import-constraint to Zones A and B.
    - Enhanced modeling of energy limitations – NYSRC and NYISO have begun to explicitly consider the potential effects of energy limitations on resource adequacy. Recent modeling enhancements recognize that the large (2675 MW) Niagara generator is limited by runoff over certain time frames and cannot

provide its full capacity in every hour. NYSRC and NYISO are continuing to investigate additional enhancements to this methodology.[410]

- Zone G has a higher CRI than zones H and I. The retirement of Indian Point Units 2 and 3 (located in Zone H) in 2020 and 2021 led a to reduction in the MRI of Zone G relative to zones H and I. This indicates that the constraints between zones G and H will bind more frequently after the retirement of Indian Point.
  - The degree to which the MRI of Zone G fell relative to zones H and I was mitigated by an update to Con Edison's Local Transmission Plan taking effect in 2021, which will change how transmission facilities in downstate New York are operated and increase the transfer limit between zones G and H.[411]
  - Thus, the Zone G and H MRIs could diverge more after Con Edison reverts to historic operation of downstate series reactor facilities beginning in summer 2023.[412]

H. Financial Capacity Transfer Rights for Transmission Projects

Investment in transmission can significantly reduce the cost of maintaining adequate installed reserve margins, enhance the deliverability of existing resources, and reduce the effects of contingencies. Recognizing these reliability benefits of transmission projects and providing them access to capacity market revenues could provide substantial incentives to invest in transmission. In this subsection, we discuss the reliability value of transmission projects and the potential for financial capacity transfer rights ("FCTRs") in providing investment signals for merchant transmission projects.[413]

Figure A-114: Breakdown of Revenues for Generation and Transmission Projects

Figure A-114 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

410 See NYSRC, *New York Controlled Area Installed Capacity Requirement for the Period May 2021 to April 2022*, section 5.2.3, available here. See also 2021 NYSRC Installed Capacity Subcommittee meeting materials pertaining to the ongoing NYISO GE ELR Study.

411 NYISO estimated that the assumed bypassing of the 71, 72, M51 and M52 series reactors in downstate New York after the retirement of both Indian Point units will increase the UPNY-CONED transfer limit between zones G and H by 1,000 MW. See NYISO presentation *2021-2022 IRM Proposed MARS Topology*, presented to Electric System Planning Working Group on May 22, 2020.

412 Con Edison proposed to place the 71, 72, M51 and M52 series reactors back in service and bypass the 41, 42 and Y49 series reactors starting summer 2023, as a solution to a Near-Term Reliability Need identified by NYISO following the 2020 Reliability Needs Assessment. See NYISO presentation *2020-2021 Reliability Planning Process: Post-RNA Base Case Updates*, presented to Electric System Planning Working Group on February 23, 2021.

413 See Recommendation 2012-1c in Section XII.

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.[414]

- 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
  - 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.[415]

- 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.

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414 Although the MSSC project increased the limit for the Central-East interface, GE-MARS simulations using the 2019 IRM topology indicated that the MRI for this interface is zero. Our assumption for increase in UPNY-SENY transfer capability is based on the following filing.

We estimated the Gross CONE for the TOTS projects using the following inputs:

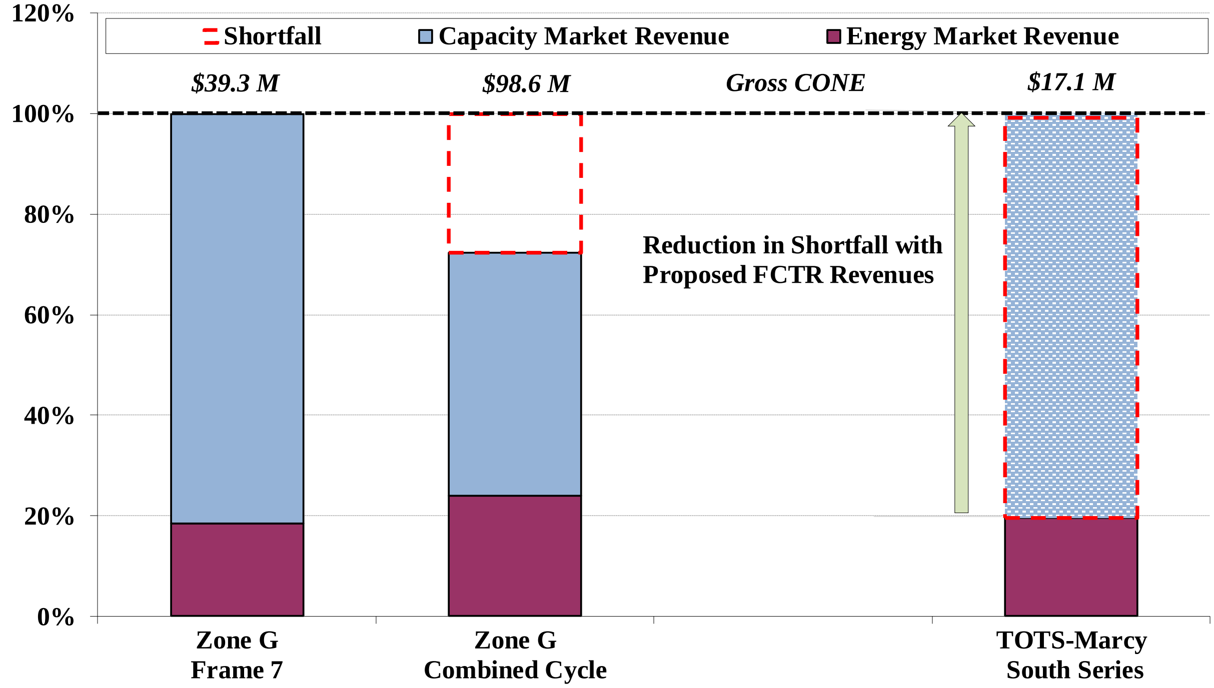
a) Carrying charge of 9.2 percent based on the WACC developed in the 2016 demand curve reset study, a 40 year project life and 15 years MACRS depreciation schedule.

b) An investment cost of $120 million for the MSSC project (see here), inflated to 2019$.

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.

415 See NYISO Market Monitoring Unit's March 10, 2020 presentation to ICAPWG titled *Locational Marginal Pricing of Capacity – Implementation Issues and Market Issues*.

Figure A-114: Breakdown of Revenues for Generation and Transmission Projects
At Level of Excess



Key Observations: Financial Capacity Transfer Rights for Transmission Projects

- Figure A-114 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.
  - 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.

I. Assessment of Capacity Accreditation Approaches

In this report, we recommend accrediting capacity suppliers based on each resource's Marginal Reliability Improvement (MRI) value. This approach differs from other methods that have been used for capacity accreditation, including Effective Load Carrying Capacity (ELCC) and simple heuristic approaches. In this subsection, we explain the difference between our recommended MRI approach and ELCC and discuss the advantages of MRI. We provide the details of our recommended MRI approach at the end of this subsection.

Approaches to Capacity Accreditation

Capacity credit refers to the amount of megawatts a resource is allowed to offer in capacity market auctions. All frameworks to establish capacity credit use methods to discount each resource's capacity, so that capacity credit reflects only what can be reliably counted on during periods of critical system need. In the NYISO market capacity credit is referred to as Unforced Capacity (UCAP). For conventional resources, UCAP is determined using the resource's EFORd, a measure of how likely it is to experience a random outage when needed.

The concept of capacity credit is closely related to the system's reliability metric, which represents how reliable the system is. NYISO targets a Loss of Load Expectation (LOLE) of 1 day in 10 years. This criterion is used to determine capacity market requirements (the IRM and LCRs), which are derived from simulations of LOLE that consider every resource's availability during hours when load shedding might occur. Ultimately, every resource's capacity credit should reflect its marginal impact on LOLE. Hence, a MW of UCAP from any resource type should correspond to a comparable impact on LOLE.

For some resource types, EFORd alone is not applicable or is not sufficient to reflect the resource's marginal impact on LOLE. Examples include intermittent renewables, energy-limited resources, very large conventional generators, and generators that can experience a common loss of a limited fuel supply (such as a pipeline outage) which they share with other generators. One reason that EFORd alone does not accurately describe these resources' impact on reliability is that EFORd represents the probability of random uncorrelated outages, but these resource types pose the risk of correlated outage or limited availability of a large amount of capacity under peak conditions.

There are multiple methods to assess the capacity credit of these resources. Capacity credit is often described relative to a hypothetical unit of 'perfect capacity' which is always available:

- Marginal Reliability Impact (MRI) – measures how an incremental amount of capacity of Resource X impacts LOLE, relative to how the same amount of 'perfect capacity' impacts LOLE.

- Effective Load Carrying Capacity (ELCC) – measures the MW quantity of 'perfect capacity' that would produce the same LOLE as a given quantity of Resource X.
  - ELCC approaches may be marginal or average, discussed further below.
- Heuristic approaches – estimate capacity credit based on rule-of-thumb approaches, such as a resource's average output in a predetermined set of hours.

Current NYISO Approach

NYISO's current approach to determining capacity credit of intermittent and energy-limited resources relies on simple heuristics. These capacity credit values are updated every four years through the Tailored Availability Metric and Expanding Capacity Eligibility processes, respectively. In both cases, resource adequacy modeling (including ELCC metrics) informs the approach, but capacity credit is ultimately set in a holistic manner based on the NYISO's judgement, but this is not guaranteed to align with a resource's impact on LOLE in each year. Our recommendation (which is described later in this subsection) would eliminate these approaches and replace them with a common data-driven framework for all resource types.

NYISO currently does not adjust capacity credit for very large conventional generators or for units with common fuel security risks. These units' UCAP is determined using their EFORd. A common outage would subsequently cause the EFORd of affected units to increase temporarily, but there is no mechanism to preemptively reflect correlated risk of these units in their UCAP.

Illustrative MRI and ELCC Approaches

MRI and ELCC approaches to capacity accreditation both rely on a probabilistic resource adequacy model that simulates LOLE. NYISO uses GE-MARS software to plan its capacity market requirements. MARS is a Monte Carlo model that inputs the existing resource mix and simulates a large variety of load and resource outage conditions to estimate the likelihood of loss-of-load events.

Both MRI and ELCC approaches add or remove generation or load in MARS and simulate LOLE. The following are examples of generalized calculation approaches, although there are multiple variations of each approach:

Example MRI Approach

An example of an MRI calculation is as follows:

1. Begin with a base case simulation reflecting the current system resource mix, with load increased so that LOLE = 0.1 days per year.
2. Add 50 MW of Resource X to (1). Calculate LOLE, which will be lower than 0.1 because the system will have more resources available.
3. Add 50 MW of perfect capacity to (1). Calculate LOLE, which will be lower than 0.1.

The MRI of Resource X is the ratio of the change in LOLE in step 2 to the change in LOLE in step 3: $MRI_X = (0.1 – LOLE2) / (0.1 – LOLE3)$. This will be less than or equal to 100 percent, because Resource X cannot be more reliable than perfect capacity.[416]

Example ELCC Approach

ELCC methods determine how much load or perfect capacity could be replaced with a given quantity of Resource X while holding LOLE constant.[417] An example of an ELCC calculation, based on a recent proposal in PJM,[418] is as follows:

1. Begin with a base case simulation reflecting the current system resource mix, including any MWs of Resource X. Increase load so that LOLE = 0.1 days per year.
2. Remove the capacity of Resource X from (1). LOLE will be above 0.1, because the system has less capacity and is therefore less reliable than (1).
3. Add perfect capacity to (2) until LOLE returns to 0.1.

The ELCC of Resource X is the quantity of perfect capacity added in (3) divided by the quantity of capacity of Resource X subtracted in (2). This percentage is less than or equal to 100 percent, because Resource X cannot be more reliable than perfect capacity.

A marginal ELCC approach subtracts only a small quantity of Resource X in (2), while an average ELCC approach subtracts all capacity of Resource X. For example, if 5,000 MW of Resource X already exists, marginal ELCC might consider how much load can be served by the next 50 to 100 MW of Resource X, while average ELCC would consider how much load can be served by all 5,000 MW. A portfolio ELCC approach is similar to average ELCC, but considers how much total load is served by a portfolio of multiple technologies simultaneously.

Comparison of MRI and ELCC Approaches

We recommend using MRI to determine capacity accreditation. The key feature of MRI is that it reflects a resource's marginal impact on LOLE, so it is consistent with ensuring reliability and with the principles of NYISO's capacity market.

MRI and Marginal ELCC approaches are likely to produce very similar capacity credit results. Both approaches fundamentally consider how LOLE is affected by an incremental quantity of

416 The amount of resource added in the MRI simulation can vary, but should be small enough so that it reflects an incremental change to the system as a whole. Our preliminary analysis suggests that a size of 50 MW is small enough to calculate a marginal impact while producing an MRI function that is monotonic with the quantity of capacity in a given location.

417 There are many variations of ELCC methods, including whether the starting simulation is at or below criteria and the order in which the studied resource and perfect capacity or load are added/removed from the model. This section outlines one recent proposed approach. For a general description, see NERC, *Methods to Model and Calculate Capacity Contributions of Variable Generation for Resource Adequacy Planning*, March 2011.

418 This is a stylized simplification of PJM's proposal – see filings by PJM Interconnection L.L.C. in FERC Docket ER21-278-000, especially October 28, 2020 Affidavit of Dr. Patricio Rocha Garrido.

Resource X compared to an incremental quantity of perfect capacity. MRI is likely to be easier to implement because it requires a fixed number of MARS runs from a common base case (i.e., step 2 and step 3 make independently-determined adjustments to the base case in step 1), while for ELCC MARS must be run iteratively (i.e., step 3 depends on the results of step 2, and determining the inputs to step 3 require some interpretation of the results of step 2). Thus, MRI methods can be automated, while ELCC methods cannot be fully automated.

Marginal approaches are preferable to average ELCC or heuristic approaches. The NYISO capacity market (and the NYISO markets in general) are designed based on the fundamental principle of economics—that prices should be consistent with the marginal cost of serving load so that suppliers have incentives to sell when their marginal cost is less than or equal to the marginal value to the system. Average ELCC methods divorce the payment an individual resource receives from its actual impact on reliability when choosing to enter the market, retire or repower. Hence, average ELCC methods provide very inefficient investment incentives.

A marginal approach such as MRI therefore offers several advantages:

- Investment signals – MRI and marginal ELCC provide efficient signals for investment and retirement. As the resource mix evolves, these signals will be vital for guiding investment in clean resources. Marginal capacity credit is key to the following:
  - Incentivizing investors to avoid technologies that have over-saturated the market. If an average or fixed credit is used, investors generally ignore this concern;
  - Incentivizing investors to add storage to intermittent renewables. If an average or fixed credit is used, the incentive to do this is greatly diminished;
  - Incentivizing investors to choose between storage projects with different durations by efficiently trading off cost and value to the system;
  - Incentivizing investors to augment the duration of storage over time (for example, by adding more batteries to an existing project). If an average or fixed credit is used, the incentive to do this is greatly diminished;
  - Incentivizing investors to efficiently repower renewable projects when they approach the end of their useful lives.
- Diversity benefits – marginal accreditation indicates the value of gaining or losing capacity of a resource type, given all the other resources in the system. As such, it accurately signals (a) diminishing returns of resources with correlated availability, and (b) the value of adding capacity of a type that complements other resources in the system. For example, if high penetrations of solar shift critical hours to an evening peak over time, the marginal capacity credit of storage would tend to increase. Average ELCC approaches also consider diversity impacts, but the resulting signals are dulled because they don't reflect how the next unit of capacity interacts with the existing resource mix.
- Avoids overpayment – marginal accreditation secures reliability at the lowest cost by paying each resource based on its marginal value to the system. Capacity prices therefore reflect the price needed to attract or retain capacity at the current level of reliability.

- An example of another market concept that relies on marginal payment is the capacity market demand curves, which pay all resources a uniform clearing price – even though capacity up to the IRM or LCR requirement theoretically provides more value than surplus capacity after that point.
- By contrast, average or portfolio ELCC approaches would directly cause UCAP requirements in the capacity market to increase, causing consumers to pay more than what is needed to attract or retain capacity. In other words, attributing UCAP to a resource in excess of its marginal contribution to reliability simply causes an offsetting increase in UCAP requirements, resulting in a transfer from consumers to suppliers.

Proposed Capacity Accreditation Method

Efficient capacity accreditation would accurately signal the marginal reliability value of each resource and improve incentives to invest in resources that best help to meet the reliability needs of a changing system. In the simplest terms, this value is determined by the expectation that the capacity of a resource will be available to maintain the reliability of the system under the tightest conditions when reliability is threatened. Our proposed means of estimated this value would consist of three components:

- *ICAP MW* – The MW of installed capacity of the individual resource,
- *Critical Period Availability Factor* – This factor accounts for the tendency for some types of resources to be less available during critical periods when resource adequacy deficiencies are most likely to occur.
- *Individual Performance Factor* – This is a discount that would account for the individual performance of the resource compared to other units of the same type.

The calculation of the payment would be as follows:

$$\text{Payment}_i = \{\text{ICAPMW}_i\} \times \{\text{Individual Performance Factor}_i\} \times \{\text{Critical Period Availability Factor}_{T,L,i}\}$$

Where:

$ICAPMW_i$ = Installed Capacity MW of unit i

$\textit{Individual Performance Factor}_i$ = 1 minus the equivalent forced outage rate of unit i. This accounts for the forced outage rate of the specific unit.[419]

419 We discuss how the NYISO's current method to calculate EFORd (and therefore, resource UCAP) tends to overestimate reliability of units with long run times, such as steam turbine units, in Appendix VI.C. This is because units that have a higher probability of having a forced outage during start-up than other operating hours are incentivized to run for additional hours to improve their EFORd. For example, a unit that is

$$\textit{Critical Period Availability Factor}_{T,L,I} = \{\text{TechMRI}_{T,L}\} \times \{\text{SizeMRI}_{i,L}\} \times \{\text{AvailabilityAdjustment\%}_{i}\}$$

Definitions:

TechMRI$_{T,L}$ = This uses the resource adequacy model to estimate the value of particular technologies relative to conventional flexible capacity. This is the MRI of Technology T in location L, which is determined by calculating the ratio of:

(a) starting with the as-found system, the ΔLOLE of adding 50 MW of technology T in location L, to

(b) starting with the as-found system, the ΔLOLE of adding 50 MW of perfect capacity in location L.

This should be done for the following technologies: land-based wind, solar PV, offshore wind, Special Case Resources, energy limited resources, hybrid storage resources, and pipeline gas-only generators. Since the marginal reliability value of these resources depends on the modeling of correlated risks in the resource adequacy model and the penetration of various technologies, further development of MARS would be required to implement this for some of these technologies. For example, land-based wind and Special Case Resources are explicitly modeled in MARS, but hybrid storage resources are not, and an additional module would be needed associate the occurrence of pipeline gas outages with resource adequacy. Other technologies would have a 1.0 for this parameter.

AvailabilityAdjustment%$_{i}$ = This term discounts the payment to a unit that is less likely to be available due to a long start time and raises the payment to a unit that is more likely to be available. Since MARS does not have the capability of modeling unit commitment, this cannot be calculated using MRI-techniques. So, this term is based on the historic availability of a unit during critical peak conditions (i.e., conditions most similar to the load shedding conditions that resource adequacy criteria are designed to avoid) relative to the average availability across the generation fleet. Past reserve shortage conditions provide the best available proxy for load shed conditions, so this term could depend on the past availability of a generator during reserve shortages, weighted on the magnitude of the shortage. The following illustrates one conceptual approach to consider:

For long lead time units (i.e., units with a start-up notification time >= 13 hours), calculate Availability$_{i,t}$ of unit i in interval t as the ratio of:

- MWh of capacity up to UOL during reserve shortage event at time t over the last 36 months when unit i was online.

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economic to run during the afternoon can improve its EFORd by submitting a Minimum Run Time of 24 hours and running for an extended period. This incentive (and the resulting effect on EFORds) would be reduced if the EFORd calculation applied different weights to different hours. For example, a weight of 10 could be applied to hours 13 to 18 and a weight of 1 could be applied to the other 8 hours of the day.

- MWh of capacity up to UOL during reserve shortage event at time t over the last 36 months.

For short lead time units (i.e., units with a start-up notification time <= 2 hours) and non-conventional resources, $Availability_{i,t}$ of unit i in interval t is equal to 1.0.

For medium lead time units (i.e., units with a start-up notification time between 2 and 13 hours), $Availability_{i,t}$ of unit i in interval t is calculated on a sliding scale between the value it would receive if it were a 13-hour start time unit and the value it would receive if it were a 2-hour start time unit.

Additional specifics of the formulation will be provided with illustrative examples in a forthcoming presentation.

$SizeMRI_{i,L}$ = This term uses the resource adequacy model to estimate how the reliability value of a resource is affected by its size. When larger units experience a forced outage, it has a larger impact on resource adequacy, so reliability values tends to fall with the size of the resource. This term represents the MRI of resources of the size of unit i in location L, which is determined by calculating the ratio of:

(a) starting with the as-found system, the ΔLOLE of adding a resource of the size of unit i in location L divided by the ICAPMW of unit i to

(b) starting with the as-found system, the ΔLOLE of adding a resource of the size of the demand curve unit in location L divided by the size of the demand curve unit.

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.

Several of our recommendations (see Section XII) for enhancing real time markets would affect energy and reserve prices significantly, which would impact resources' market revenues and investment incentives. In subsection D, we evaluate the potential impact of a subset of these recommendations on the net revenues of different types of resources and total consumer costs in New York City.

A. Gas-Fired and Dual Fuel Units Net Revenues

We estimate the net revenues the markets would have provided to three types of 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 in Long Island, the 345kV portion of New York City, the Hudson Valley Zone, the Capital Zone, and the West 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.[420] 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. Future years' net energy and ancillary services and capacity revenues are based on zonal price futures. We also estimate historical capacity revenues based on spot capacity prices.

Table A-20 to Table A-23: 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.[421] 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.

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420 Prices at locations on the 345 kV network in New York city often differ from those on the lower-voltage 138 kV network, which typically experiences more localized congestion.

421 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.

- Generators in New York City, Long Island and Lower Hudson Valley are assumed to have dual-fuel capability. During hourly OFOs in New York City and Long Island, generators are assumed to offer in the day-ahead market as follows:

Table A-20: Day-ahead Fuel Assumptions During Hourly OFOs[422]

Technology	Gas-fired	Dual Fuel
Combined Cycle	Min Gen only	Oil
Gas Turbine	No offer	Oil
Steam Turbine	Min Gen only	Oil/ Gas**

- All peaking units incur a $2.00/MWh cost when committed to provide operating reserves. This assumption is reflective of historical reserve market offers and is intended to represent costs incurred to make a generator available, secure fuel, and/or compensate for performance risks when providing reserves.

- Capacity revenues are estimated based on futures prices for the 2021/2022, 2022/2023, and 2023/2024 capability years traded on the ICE exchange in February 2021.

- 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-21: Gas and Oil Price Indices and Other Charges by Region

Region	Gas Price Index	Transportation & Other Charges ($/MMBTU)			Intraday Premium/ Discount
		Natural Gas	*Diesel/ ULSD*	*Residual Oil*	
West and Central	April - November: Tennessee Zn 4 - 200 Leg December - March: Niagara	$0.27	$2.00	$1.50	10%
Capital	Iroquois Zn 2	$0.27	$2.00	$1.50	10%
Hudson Valley (Dutchess)	Iroquois Zn2	$0.27	$1.50	$1.00	10%
Hudson Valley (Rockland)	TETCO M3	$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 15 MW.

422 **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-22: New Gas-fired Unit Parameters for Net Revenue Estimates[423]

Characteristics	CC 1x1	3XA65	Frame 7HA.02
Summer Capacity (MW)	617	167	358
Winter Capacity (MW)	648	188	370
Summer Heat Rate (Btu/kWh)	6738	9668	9365
Winter Heat Rate (Btu/kWh)	6729	9445	9300
Min Run Time (hrs)	4	1	1
Variable O&M - Gas (2021$/MWh)	$2.6	$12.8	$1.4
Variable O&M - Oil (2021$/MWh)	$3.5	$12.9	$11.1
Startup Cost (2021$)	$26,600	$0	$26,600
Startup Cost (MMBTU)	3490	100	490
EFORd	2.90%	2.17%	4.30%

Table A-23: 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 (2021$/MWh)	$10.1	$5.1	$6.2
Startup Cost (2021$)	$6,770	$1,354	$585
Startup Cost (MMBTU)	3500	50	60
EFORd	5.14%	10.46%	19.73%

Figure A-115 and Figure A-116: Forward Prices and Implied Heat Rate Trends

We developed the hourly day-ahead power price forecast for each zone by adjusting the 2020 LBMPs using the ratio of (a) monthly forward prices, and (b) the observed monthly average

423 These parameters are based on technologies studied as part of the 2020 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 2020 ICAP Demand Curve reset study. See *Independent Consultant Study to Establish New York ICAP Demand Curve Parameters for the 2021/2022 through 2024/2025 Capability Years – Final Report*.

prices in 2020. Net revenues from 2021 to 2023 are estimated using forward prices for power.[424] We held the reserve prices for future years at their 2020 levels.

Figure A-115 shows the variation in the forward prices and implied marginal heat rates for Zone A and Zone G over a six month (July-Dec 2020) trading period. Figure A-116 shows the monthly forward power and gas prices for the 2021-2023 period along with the observed monthly average prices during the 2018-2020 period.

Figure A-115: Forward Prices and Implied Marginal Heat Rates by Transaction Date

2021, 2022, & 2023 Strip Prices from July to December 2020

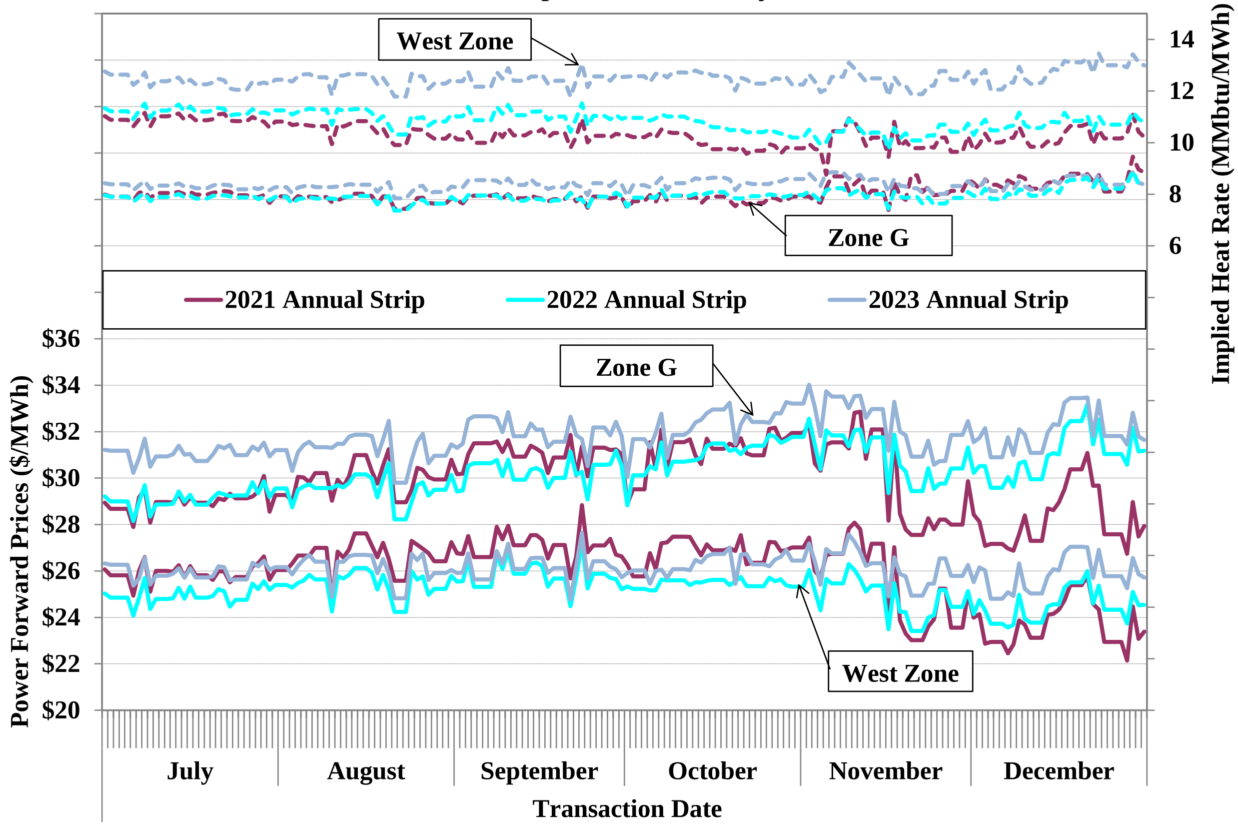
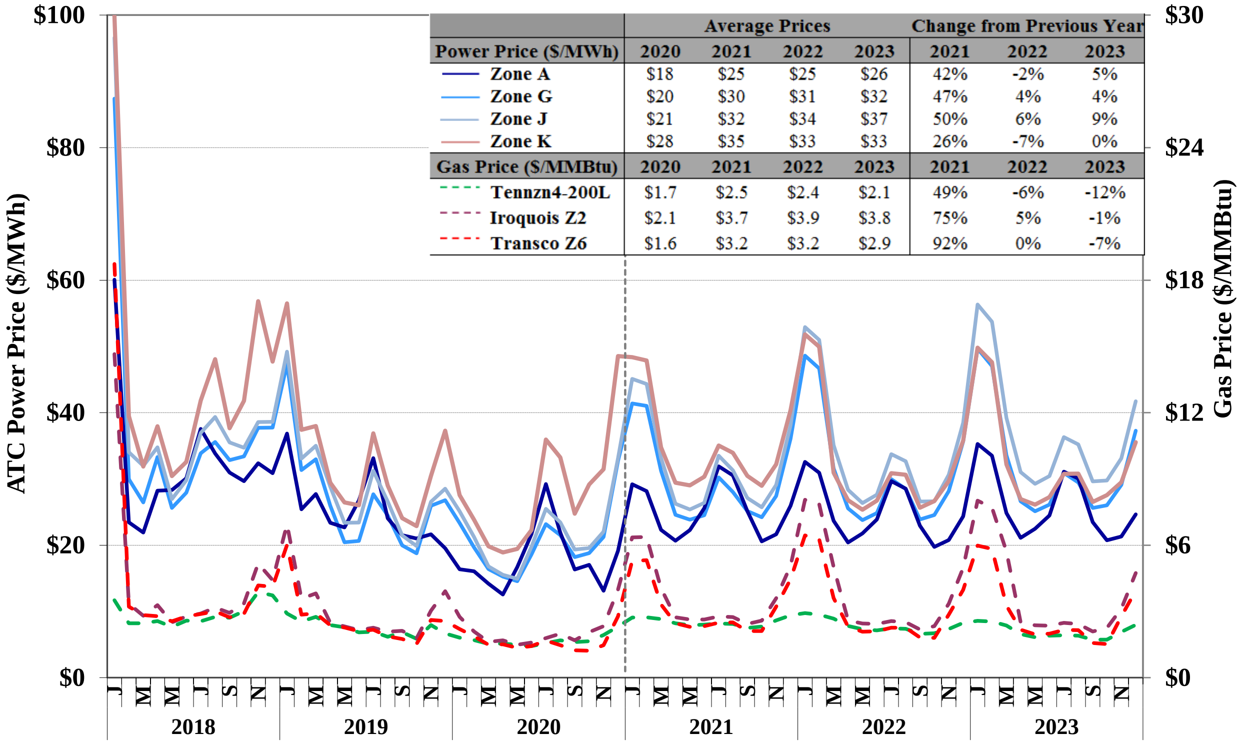


Figure A-116 shows that forward power prices for 2021 were volatile in the last six months of 2020, ranging from $27 to $34 per MWh in Zone G and $22 to $29 in Zone A. This analysis uses the trailing 90-day average of forward prices as of January 1, 2021. Forwards transaction prices suggest energy and gas prices are expected to increase significantly from 2020 levels. Forward implied heat rates in zone G are relatively static, consistent with a lack of expected major changes in supply or transmission capability in Zone G during this timeframe.

424 For power forward prices between 2021 and 2023, we used OTC Global Holdings' forward strips published by SNL Energy.

Figure A-116: Past and Forward Price Trends of Monthly Power and Gas Prices
2018 – 2023



	Average Prices				Change from Previous Year		
Power Price ($/MWh)	2020	2021	2022	2023	2021	2022	2023
Zone A	$18	$25	$25	$26	42%	-2%	5%
Zone G	$20	$30	$31	$32	47%	4%	4%
Zone J	$21	$32	$34	$37	50%	6%	9%
Zone K	$28	$35	$33	$33	26%	-7%	0%
Gas Price ($/MMBtu)	2020	2021	2022	2023	2021	2022	2023
Tennzn4-200L	$1.7	$2.5	$2.4	$2.1	49%	-6%	-12%
Iroquois Z2	$2.1	$3.7	$3.9	$3.8	75%	5%	-1%
Transco Z6	$1.6	$3.2	$3.2	$2.9	92%	0%	-7%

Figure A-117 to Figure A-122: 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.[425] Net revenues and CONE values are shown per kW-year of Summer Installed Capability. Table A-24 and Table A-25 show our estimates of net revenues and run hours for all the locations and gas unit types in 2020. Table A-26 and Table A-27 shows a detailed breakout of quarterly net revenues and run hours for all gas-fired units in 2020.

425 The CONE for the new technology types is based on cost estimated from the 2020 NYISO ICAP Demand Curve Reset report. See *Independent Consultant Study to Establish New York ICAP Demand Curve Parameters for the 2021/2022 through 2024/2025 Capability Years – Final Report*.

The financing assumptions and insurance costs are sourced from the 2020 NYISO ICAP Demand Curve Reset report . 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-117: Net Revenue & Cost for Fossil Units in West Zone
2018-2023 (2021 - 2023 projected)

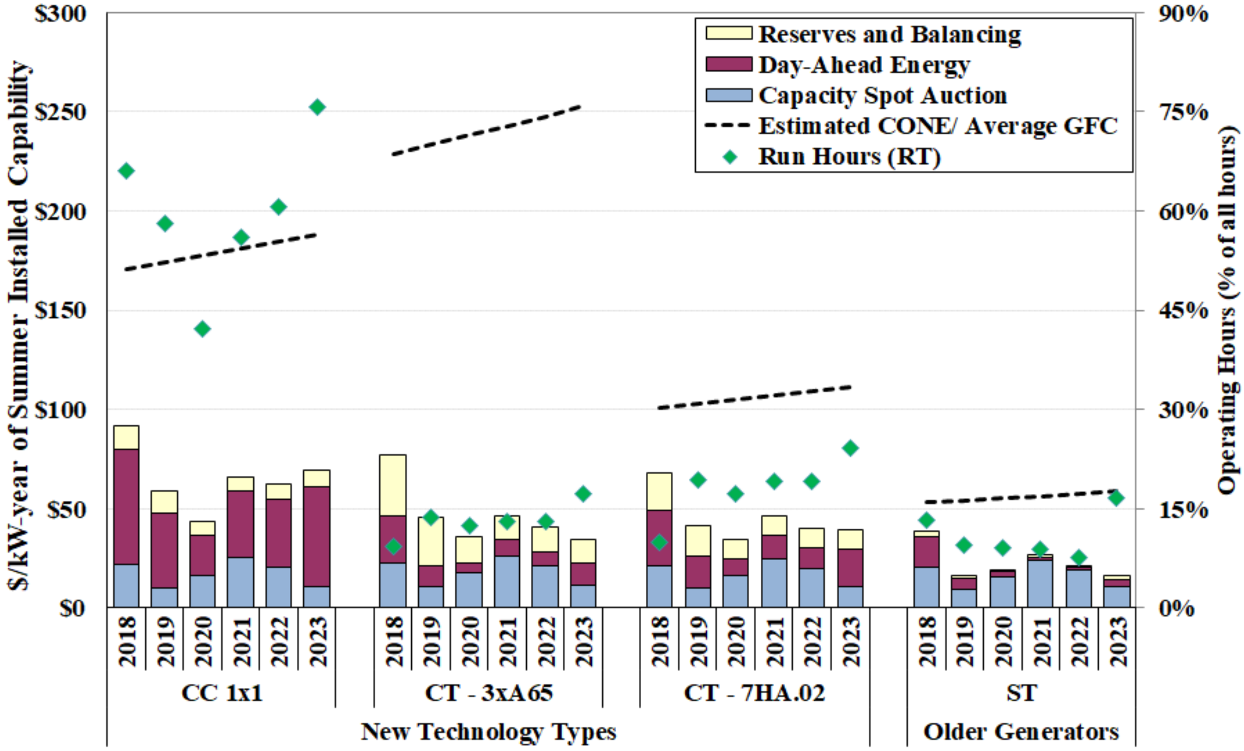


Figure A-118: Net Revenue & Cost for Fossil Units in Central Zone
2018-2023 (2021 - 2023 projected)

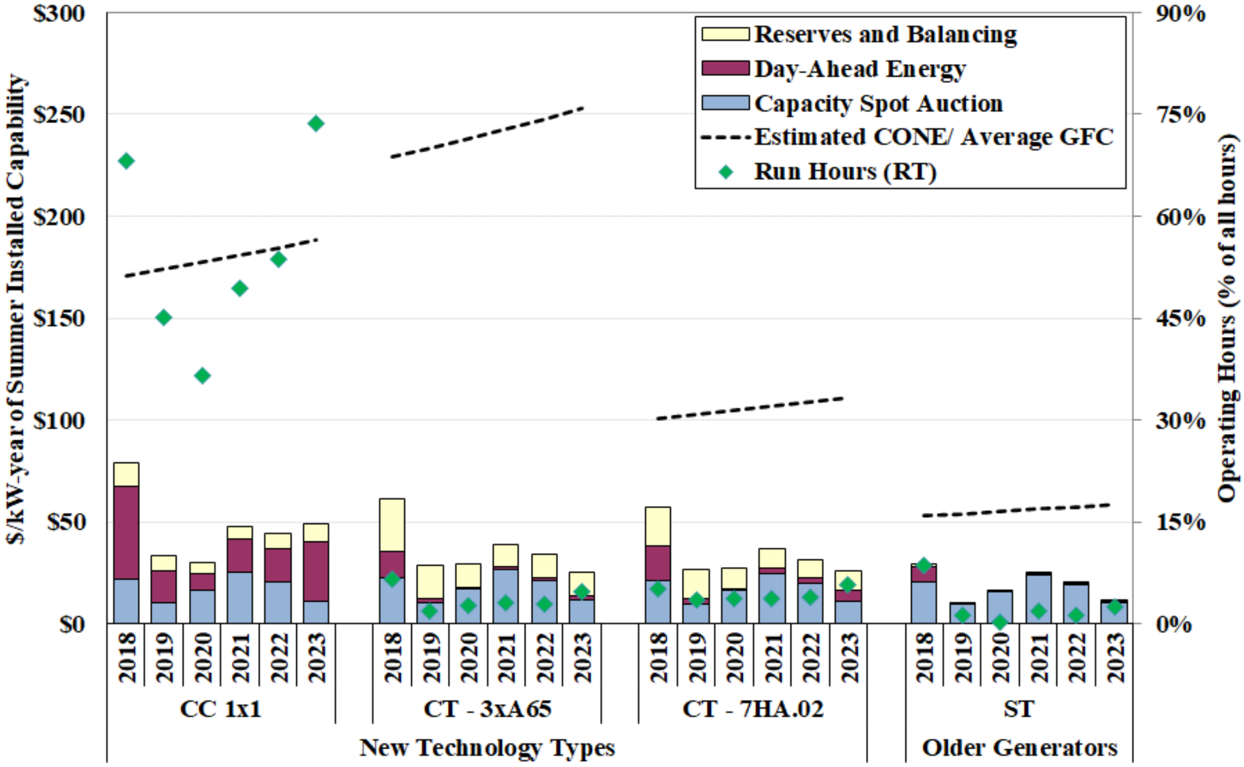


Figure A-119: Net Revenue & Cost for Fossil Units in Capital Zone
2018-2023 (2021 - 2023 projected)

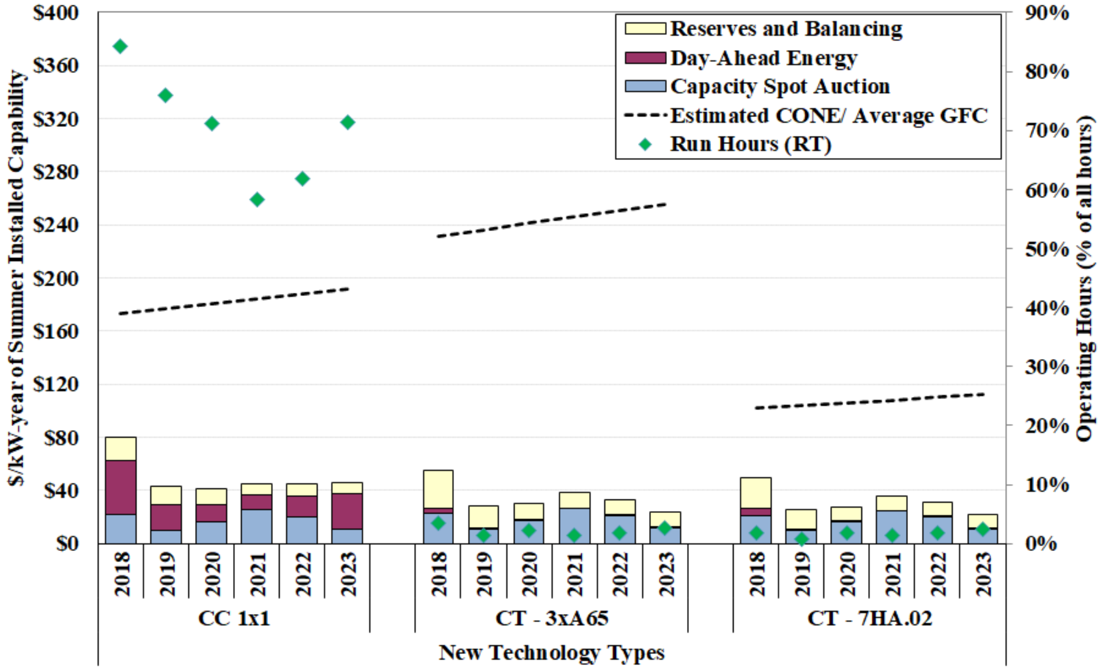
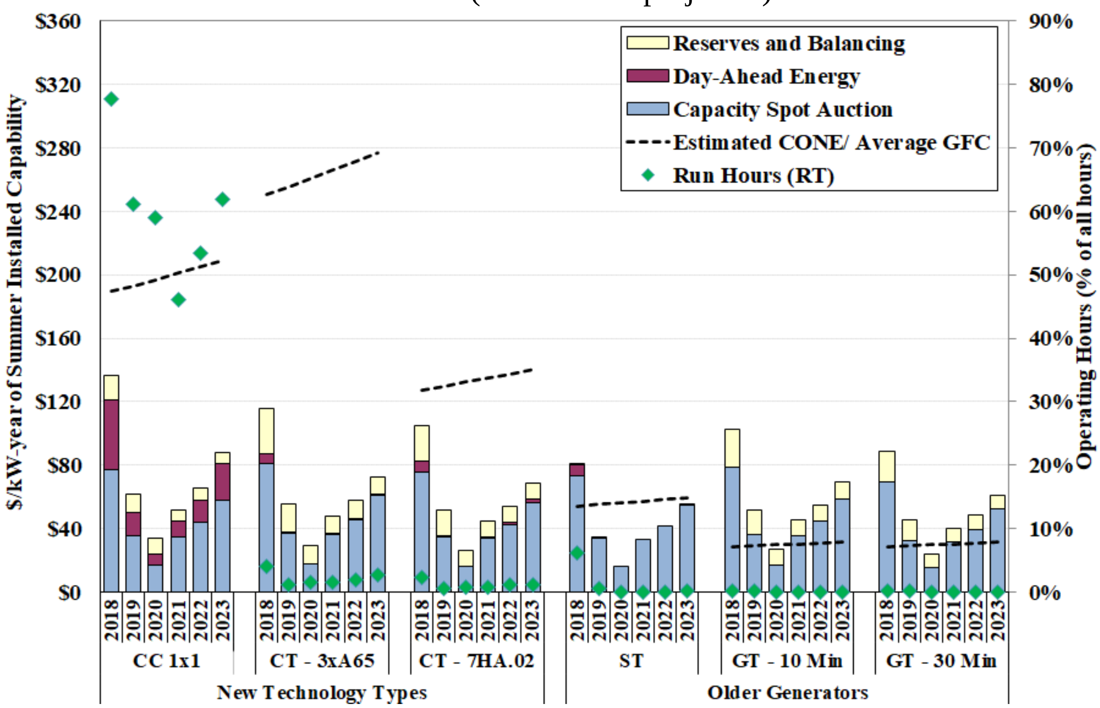


Figure A-120: Net Revenue & Cost for Fossil Units in Hudson Valley[426]
2018-2023 (2021 - 2023 projected)



426 Net revenues use Iroquois Z2 gas prices for new technologies interconnecting in Dutchess County. Results using TETCO M3 gas prices for units interconnecting in Rockland County are shown in Table A-25.

Figure A-121: Net Revenue & Cost for Fossil Units in New York City
2018-2023 (2021 - 2023 projected)

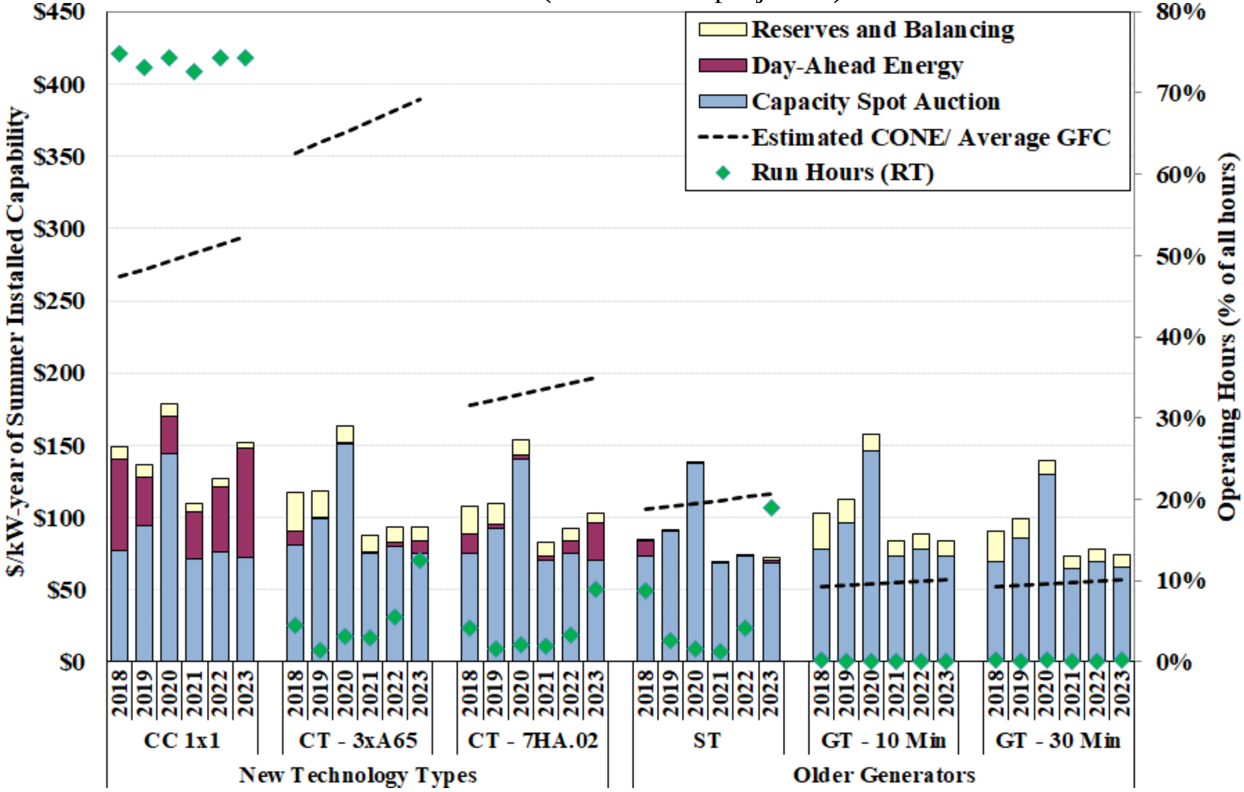


Figure A-122: Net Revenue & Cost for Fossil Units in Long Island
2018-2023 (2021 - 2023 projected)

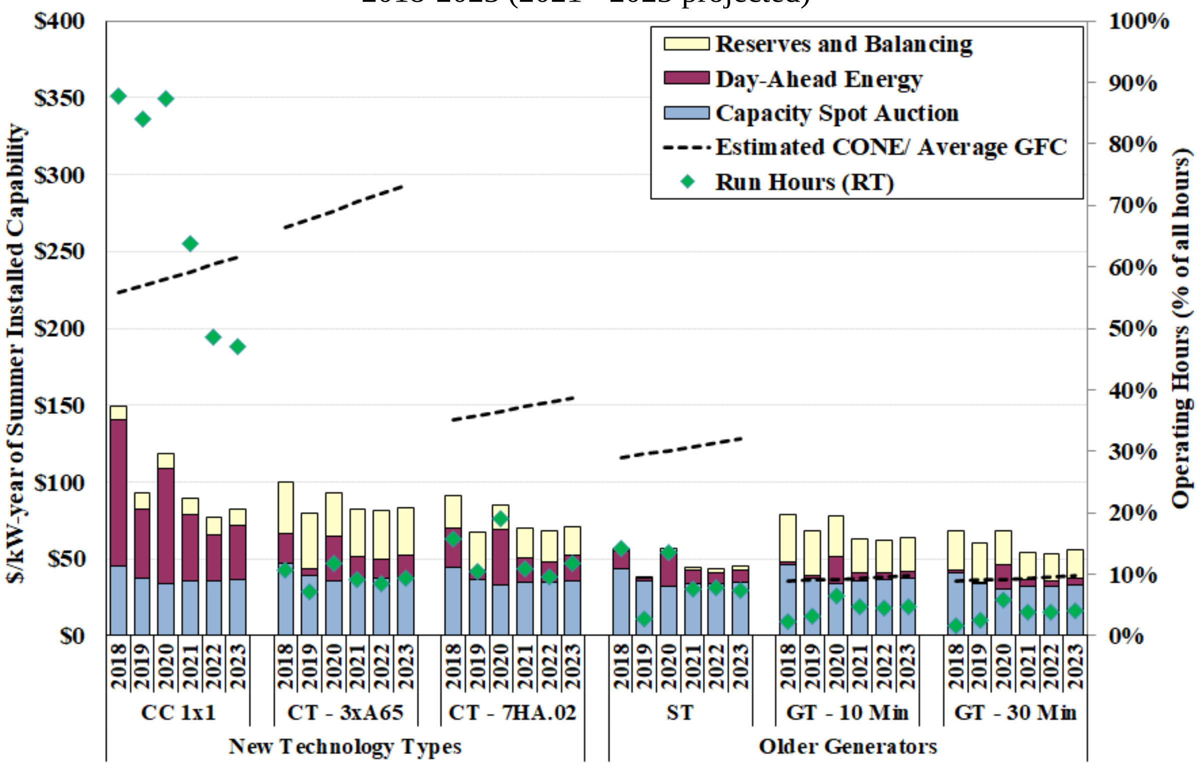


Table A-24: Net Revenue for Gas-Fired & Dual Fuel Units in Zones A-F
2020

Location	Unit Type	Capacity	2020 Net Revenue ($/kW-yr)			Real Time Run Hours
			Day-Ahead Energy	Reserves + Balancing	Total	
Capital Zone	CC 1x1	$17	$12	$12	$41	6237
	CT - 7HA.02	$16	$1	$11	$27	154
	CT - 3xA65	$17	$0	$12	$30	195
Captl (Tennessee Zone 5 Gas)	CC 1x1	$17	$23	$11	$51	6603
	CT - 7HA.02	$16	$2	$11	$29	281
	CT - 3xA65	$17	$1	$13	$31	341
Central Zone	CC 1x1	$17	$8	$6	$30	3198
	CT - 7HA.02	$16	$1	$10	$27	329
	CT - 3xA65	$17	$0	$12	$30	240
	ST	$16	$0	$0	$16	23
Central (Dominion North Gas)	CC 1x1	$17	$14	$9	$40	5079
	CT - 7HA.02	$16	$3	$10	$29	538
	CT - 3xA65	$17	$1	$12	$30	340
Central (Tennessee Zone 5 Gas)	CC 1x1	$17	$7	$5	$29	2944
	CT - 7HA.02	$16	$1	$10	$27	300
	CT - 3xA65	$17	$0	$11	$29	234
	ST	$0	$0	$0	$0	0
Central (Niagara Gas)	CC 1x1	$17	$8	$6	$31	3263
	CT - 7HA.02	$16	$1	$10	$27	326
	CT - 3xA65	$17	$0	$12	$30	244
	ST	$16	$0	$0	$16	68
West Zone	CC 1x1	$17	$20	$7	$44	3699
	CT - 7HA.02	$16	$8	$10	$35	1519
	CT - 3xA65	$17	$5	$13	$36	1099
	ST	$16	$2	$1	$19	797

Table A-25: Net Revenue for Gas-Fired & Dual Fuel Units in Zones G-K
2020

Location	Unit Type	Capacity	2020 Net Revenue ($/kW-yr)			Real Time Run Hours
			Day-Ahead Energy	Reserves + Balancing	Total	
Hudson Valley	CC 1x1	$17	$7	$10	$34	5173
	CT - 7HA.02	$16	$0	$10	$27	60
	GT - 10 Min	$17	$0	$10	$27	1
	GT - 30 Min	$15	$0	$9	$24	3
	CT - 3xA65	$17	$0	$11	$29	136
	ST	$16	$0	$0	$16	0
Hudson Valley (Tetco Gas)	CC 1x1	$17	$25	$13	$55	7782
	CT - 7HA.02	$16	$3	$12	$32	254
	GT - 10 Min	$17	$0	$10	$27	6
	GT - 30 Min	$15	$0	$9	$24	24
	CT - 3xA65	$17	$1	$12	$31	352
	ST	$16	$0	$0	$16	114
Long Island	CC 1x1	$34	$75	$10	$118	7644
	CT - 7HA.02	$33	$36	$15	$85	1672
	GT - 10 Min	$34	$18	$26	$78	572
	GT - 30 Min	$30	$16	$22	$68	506
	CT - 3xA65	$35	$30	$28	$93	1032
	ST	$32	$23	$2	$57	1184
Long Island (VS/ Barrett Load Pocket)	CC 1x1	$34	$80	$7	$121	7734
	CT - 7HA.02	$33	$37	$8	$78	1839
	GT - 10 Min	$34	$7	$23	$64	488
	GT - 30 Min	$30	$6	$19	$56	426
	CT - 3xA65	$35	$23	$22	$80	1032
	ST	$32	$14	$3	$50	1890
NYC	CC 1x1	$144	$26	$9	$179	6510
	CT - 7HA.02	$141	$3	$10	$154	190
	GT - 10 Min	$146	$0	$11	$157	4
	GT - 30 Min	$130	$0	$9	$139	17
	CT - 3xA65	$151	$1	$12	$164	278
	ST	$137	$0	$0	$138	137

Table A-26: Quarterly Net Revenue and Run Hours for Gas-Fired & Dual Fuel Units in Zones A-F
2020

Location	Unit Type	DA Energy Profits ($/kW-yr)				Reserves + Balancing Profits ($/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 2	Qtr 3	Qtr 4
Capital Zone	CC 1x1	$2	$1	$5	$5	$3	$3	$3	$4	1584	1269	1844	1540
	CT - 7HA.02	$0	$0	$0	$0	$2	$2	$2	$4	1	2	70	81
	CT - 3xA65	$0	$0	$0	$0	$3	$3	$3	$4	14	24	98	59
Captl (Tennessee Zone 5 Gas)	CC 1x1	$3	$2	$9	$10	$3	$2	$3	$4	1783	1037	2144	1640
	CT - 7HA.02	$0	$0	$1	$1	$2	$2	$2	$4	1	11	100	169
	CT - 3xA65	$0	$0	$0	$1	$3	$2	$3	$5	17	30	132	162
Central Zone	CC 1x1	$0	$1	$6	$1	$1	$1	$2	$2	418	584	1675	521
	CT - 7HA.02	$0	$0	$0	$0	$2	$2	$2	$4	20	63	129	117
	CT - 3xA65	$0	$0	$0	$0	$3	$2	$3	$4	10	49	118	63
	ST	$0	$0	$0	$0	$0	$0	$0	$0	0	0	0	23
Central (Dominion North Gas)	CC 1x1	$1	$1	$10	$2	$2	$1	$3	$3	951	741	2144	1243
	CT - 7HA.02	$0	$0	$2	$0	$2	$2	$2	$3	22	86	231	199
	CT - 3xA65	$0	$0	$1	$0	$3	$3	$3	$4	16	54	172	99
	ST	$0	$0	$0	$0	$0	$0	$0	$0	23	0	159	46
Central (Tennessee Zone 5 Gas)	CC 1x1	$0	$1	$6	$0	$0	$1	$3	$1	88	531	2037	287
	CT - 7HA.02	$0	$0	$1	$0	$2	$2	$2	$3	10	63	139	89
	CT - 3xA65	$0	$0	$0	$0	$3	$2	$3	$4	5	49	129	51
	ST	$0	$0	$0	$0	$0	$0	$0	$0	0	0	0	0
Central (Niagara Gas)	CC 1x1	$0	$0	$1	$0	$2	$2	$2	$4	20	53	136	118
	CT - 7HA.02	$0	$0	$1	$0	$2	$2	$2	$4	20	53	136	118
	CT - 3xA65	$0	$0	$0	$0	$3	$2	$3	$4	10	43	127	64
	ST	$0	$0	$0	$0	$0	$0	$0	$0	0	0	46	23
West Zone	CC 1x1	$0	$6	$12	$1	$1	$2	$2	$2	494	1053	1654	498
	CT - 7HA.02	$0	$2	$6	$0	$2	$2	$2	$4	171	553	511	283
	CT - 3xA65	$0	$1	$4	$0	$3	$3	$3	$4	151	397	418	133
	ST	$0	$0	$2	$0	$0	$0	$1	$0	0	205	592	0

Table A-27: Quarterly Net Revenue and Run Hours for Gas-Fired & Dual Fuel Units in Zones G-J

2020

Location	Unit Type	DA Energy Profits ($/kW-yr)				Reserves + Balancing Profits ($/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 2	Qtr 3	Qtr 4
Hudson Valley	CC 1x1	$0	$1	$5	$1	$3	$2	$3	$3	1442	839	1775	1113
	CT - 7HA.02	$0	$0	$0	$0	$2	$2	$2	$3	1	2	57	0
	GT - 10 Min	$0	$0	$0	$0	$3	$2	$2	$3	1	0	0	0
	GT - 30 Min	$0	$0	$0	$0	$2	$2	$2	$3	1	0	0	2
	CT - 3xA65	$0	$0	$0	$0	$3	$2	$3	$4	3	25	92	16
	ST	$0	$0	$0	$0	$0	$0	$0	$0	0	0	0	0
Hudson Valley (Tetco Gas)	CC 1x1	$3	$1	$10	$11	$4	$4	$3	$3	2095	1771	2132	1783
	CT - 7HA.02	$0	$0	$1	$2	$2	$2	$2	$5	1	11	93	149
	GT - 10 Min	$0	$0	$0	$0	$3	$2	$2	$3	1	0	5	0
	GT - 30 Min	$0	$0	$0	$0	$2	$2	$2	$3	1	0	5	18
	CT - 3xA65	$0	$0	$0	$1	$3	$2	$3	$5	8	30	123	191
	ST	$0	$0	$0	$0	$0	$0	$0	$0	0	0	46	68
Long Island	CC 1x1	$5	$6	$43	$20	$3	$3	$2	$2	1961	1771	2144	1768
	CT - 7HA.02	$0	$0	$31	$5	$3	$4	$4	$5	82	234	855	501
	GT - 10 Min	$0	$0	$18	$0	$4	$3	$11	$7	32	61	339	140
	GT - 30 Min	$0	$0	$16	$0	$4	$3	$9	$6	28	52	305	121
	CT - 3xA65	$0	$0	$27	$3	$5	$6	$9	$8	69	140	518	304
	ST	$0	$0	$23	$0	$0	$0	$1	$0	0	0	933	250
Long Island (VS/ Barrett Load Pocket)	CC 1x1	$16	$9	$32	$23	$1	$3	$1	$2	2052	1771	2144	1768
	CT - 7HA.02	$5	$2	$20	$9	$2	$2	$1	$3	193	297	761	589
	GT - 10 Min	$1	$0	$5	$1	$3	$3	$8	$9	41	68	217	161
	GT - 30 Min	$1	$0	$5	$1	$3	$2	$7	$7	35	58	187	146
	CT - 3xA65	$3	$1	$13	$6	$4	$5	$6	$8	98	145	417	373
	ST	$1	$1	$10	$3	$0	$0	$1	$1	205	159	1002	524
NYC	CC 1x1	$2	$2	$12	$10	$3	$3	$2	$3	1618	1437	1890	1564
	CT - 7HA.02	$0	$0	$1	$2	$2	$2	$2	$4	1	2	110	78
	GT - 10 Min	$0	$0	$0	$0	$3	$2	$2	$4	1	0	3	0
	GT - 30 Min	$0	$0	$0	$0	$2	$2	$2	$3	1	0	2	14
	CT - 3xA65	$0	$0	$0	$1	$3	$2	$3	$4	5	23	115	135
	ST	$0	$0	$0	$0	$0	$0	$0	$0	0	0	68	68

Key Observations: Net Revenues of Gas-fired and Dual Fuel Units

- Year-Over-Year Changes – Total estimated net revenues in 2020 were higher in some locations (particularly NYC and Long Island) and lower in other locations compared to 2019. Energy and ancillary services revenues were lower in almost all locations, but were offset by higher capacity revenues in some areas.
  - As discussed in Section I of the Appendix, 2020 experienced lower load levels and lower gas prices, which contributed to lower energy prices and lower implied marginal heat rates in most zones across the state.[427] Consequently, energy margins and E&AS net revenues were low relative to other recent years in most locations (with the exception of Long Island).
  - The lower energy margins in 2020 resulted in the net revenues of nearly all units in most locations (with the exception of Long Island) being less reliant on day-ahead energy revenues when compared to balancing and reserve revenues. This illustrates the importance of improving the efficiency of real-time energy and reserve markets as the amount of renewable resources with low marginal costs increases. In markets with high penetration of renewables, the load served by fossil-fired resources would decrease and the average energy prices are likely to decline. Consequently, the reliance of resources on the real-time energy and reserve markets would increase.
  - Capacity prices increased moderately in the rest-of-state area and by a large amount in New York City. In contrast, capacity prices in the Lower Hudson Valley declined and were set at the rest-of-state level. These price changes were largely driven by changes in the Installed Reserve Margin and Locational Capacity Requirements (see subsection subsection VI.E of the appendix). As a result, net revenues for resources in New York City increased substantially in 2020 despite a decline in energy and ancillary services market net revenues.
- *Estimated Future Net Revenues* – Given the current pricing of forward contracts, the net E&AS revenues of most units in the 2021 to 2023 timeframe are likely to be higher than in 2020 as the forward power prices and the implied marginal heat rates are rising in most regions. Ultimately, 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 2020 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 (partly reflecting the impacts of Covid-19 in 2020), has led to net revenues being lower than the annualized CONE for all new hypothetical units in 2020.[428]

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427 Demand in 2020 was unusually low due to the impact of the Covid-19 pandemic in most areas, resulting in lower implied heat rates.

428 See discussion of wholesale price trends in 2020 in Appendix I.A.

- *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 most 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.
    - The estimated net E&AS revenues of existing steam turbine units were negligible in both 2019 and 2020. Net revenues for these units exceeded average GFC estimates only in New York City, where capacity prices increased significantly in 2020. 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.
    - Environmental regulations will require GTs and STs in New York City to incur significant additional capital expenditures to remain in operation. First, the New York DEC will 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.[429] The owners of affected units filed initial compliance plans in 2020, indicating that some existing units will retire and others will consider repowering or continued operation.[430] Second, a City of New York ordinance will prevent steam turbines from burning residual oil beginning in 2022, so steam turbines have to install facilities for burning diesel oil to remain dual-fueled.[431]
- *Reserve Market Revenues for Gas Turbines* – The estimated net E&AS revenues of gas turbines were largely driven by reserve and real-time balancing market revenues in most locations. Contributions from day-ahead energy revenues for gas turbines were only significant in areas with frequent major congestion (i.e., the West zone and Long Island) or in years when market prices were unusually high during some periods (e.g., 2018).

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

429 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

430 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 article.

431 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*.

Fitzpatrick and Nine Mile Unit 1 buses (for Central Zone). For future years, bus prices are estimated by assuming the same basis differential as 2020.

Figure A-123: Net Revenues for Nuclear Plants

Figure A-123 shows the net revenues and the US-average operating costs for the nuclear units from 2018 to 2023. 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.[432]
- 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 2018 through 2019.[433]
- The nuclear units located in upstate zones are eligible for additional revenue in the form of Zero Emission Credits ("ZECs").[434] 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.

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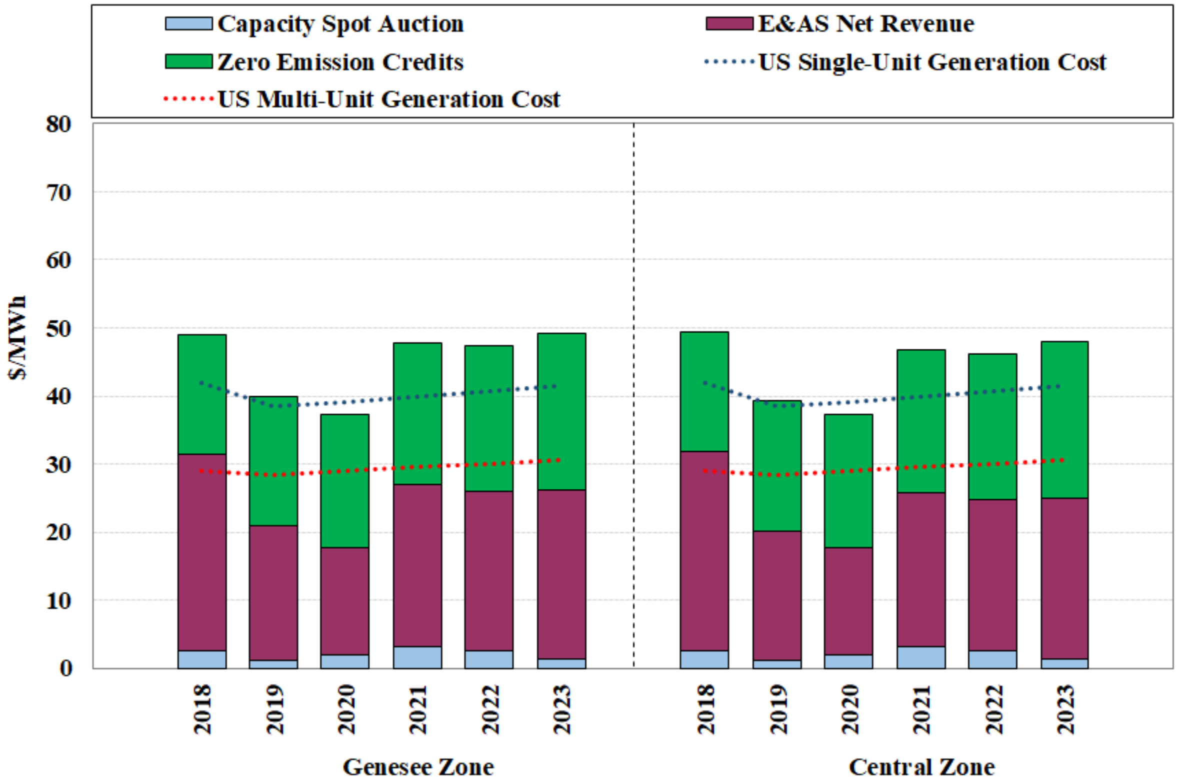
432 The refueling cycle for nuclear plants is typically 18-24 months. We assume a reduced capacity factor in March and April every year to enable a year over year comparison of net revenues.

433 The average cost of operation of nuclear plants in the US are based on NEI/ EUCG reports and presentations. See here.

434 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.

Figure A-123: Net Revenue of Existing Nuclear Units
2018-2023



Key Observations: Net Revenues of Existing Nuclear Units

- *Year-Over-Year Changes* – The estimated total net revenues for nuclear units in the upstate zones decreased from 2019 to 2020 due to low 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 2020 levels due to higher energy prices and slightly higher ZEC prices.

- *Incentives for Existing Nuclear Plants* – The estimated total net revenues of nuclear plants were below the U.S. single-unit average generation costs in 2020 due to low energy prices at upstate plant locations. In future years, total net revenues are expected to be marginally at or above the average cost of single unit plants, due in large part to ZEC revenues. ZEC revenues account for approximately 52 percent of the total revenues earned in 2020.

  - 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. 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 in the Lower Hudson Valley and Capital zones, land-based wind in the Central and North zones, and offshore wind plants interconnecting in the Long Island and New York City zones. For each of these technologies, we estimated the revenues from the NYISO markets and the state and federal incentive programs.

Table A-28 and Figure A-124: 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. The capacity factors are based on location-specific resource availability and technology performance data.[435]
- The capacity revenues for solar PV, onshore wind, and offshore wind units are calculated using prices from the spot capacity market. The capacity values of renewable resources are based on the factors (34, 2, and 50 percent for Winter Capability Periods and 16, 46, and 30 percent for Summer Capability Periods for onshore wind, solar PV, and offshore wind, respectively) specified in the February 2021 NYISO Installed Capacity Manual.[436]
- 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 2018 through 2021. Future REC prices are derived by inflating the 2020 Tier 1 REC sale price.[437] 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.[438]

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435 Assumed yearly capacity factors for solar PV, Onshore, and Offshore wind units are sourced from the NYISO's ongoing Renewable Technology Cost study. Hourly generation profiles from 2020 NREL ATB are adjusted to match the annual average capacity factors from Renewable Technology Cost study. For locations where capacity factor information was not available in the Renewable Technology Cost study, we use information from the CES whitepaper, see here.

436 The capacity value for renewable resources are available in Section 4.5.b of the ICAP Manual in the tables labeled "Unforced Capacity Percentage – Land Based Wind" and "Unforced Capacity Percentage – Solar." For estimated capacity value of Offshore Wind resources, see NYISO, *Buyer-Side Mitigation Renewable Exemption Study Draft Study Results*, presented to Installed Capacity Working Group on May 5, 2021.

437 For more information on the recent RES Tier 1 REC procurements, see here. 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.

438 See Appendix A and B of NYSERDA's October 2019 "Launching New York's Offshore Wind Industry: Phase I Report".

- 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.[439] We incorporate the value of these federal incentives as an additional revenue stream for solar PV and wind units.[440]

- Renewable generators are assumed to incur a lower cost of capital due to the availability of revenues from sale of renewable energy credits, which carry a lower risk relative to NYISO market revenues. Accordingly, we assumed a weighted average cost of capital blending merchant financing costs and regulated financing costs (based on the cost of capital for regulated utilities in New York) for estimating the CONE of renewable units.

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-28 shows cost estimates for solar PV, onshore wind and offshore wind units we used for a unit that commence operations in 2020. The data shown are largely based on Renewable Technology Costs study.[441]

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439 For solar PV, the ITC is 26 percent of the eligible investment costs for projects that commence construction by end of 2020. It was 30 percent for projects that began construction in 2019 or earlier. It will step down to 22 percent for projects starting construction in 2023. Solar projects that enter service after 2025 will qualify for a 10 percent ITC.

For offshore wind, the ITC is 30 percent of the eligible investment costs for projects that commence construction before 2026. The safe harbor period for the projects is up to ten years. Consequently, we assumed 30 percent ITC for offshore wind projects.

The Production Tax Credit available to onshore wind projects is 40 percent for projects beginning construction in 2019, 60 percent for projects beginning construction in 2020 and 2021, and 0 percent afterward. However, developers of onshore wind can safe harbor their investments for a maximum of four calendar years and receive PTC. 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.

440440 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.

441 The assumed investment costs and fixed O&M costs for solar PV, onshore wind and offshore wind are based on the NYISO's ongoing study on Renewable Technology Costs, see here. The assumed investment cost trajectory over the years for onshore wind, solar PV, and offshore wind units was based on "Moderate" cost curves from 2020 NREL ATB. We used TRG 6 cost decline curve for onshore wind, and TRG 1 for offshore wind. 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). CONE calculation for offshore wind in NYC assumes four percent city tax rate, and it is assumed that the offshore wind unit in NYC and LI zones will not be subjected to any property tax payments. Property tax payments for onshore wind and solar PV projects are 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 = 0.5% of capital cost.

The table also shows the capacity factor and capacity value assumptions we used for calculating net revenues for these renewable units.

Table A-28: Cost and Performance Parameters of Renewable Units

Parameter	Utility-Scale Solar PV	Onshore Wind	Offshore Wind
Investment Cost (2020$/kW AC basis)	*Capital/LHV*: $1361	*Upstate NY*: $1577	*NYC/Long Island* : $4277
Fixed O&M (2020$/kW-yr)	$27	$48	$133
Federal Incentives	ITC	PTC	ITC
Project Life	20 years		
Depreciation Schedule	5-years MACRS		
Average Annual Capacity Factor	Capital/LHV: 16.8%	Central: 35.0% North: 39.0%	NYC/LI: 45%
Unforced Capacity Percentage	Summer: 46% Winter: 2%	Summer: 16% Winter: 34%	Summer: 30% Winter: 50%
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 $90/MWh NYC / $85/MWh LI (2020$) less energy and capacity prices.		

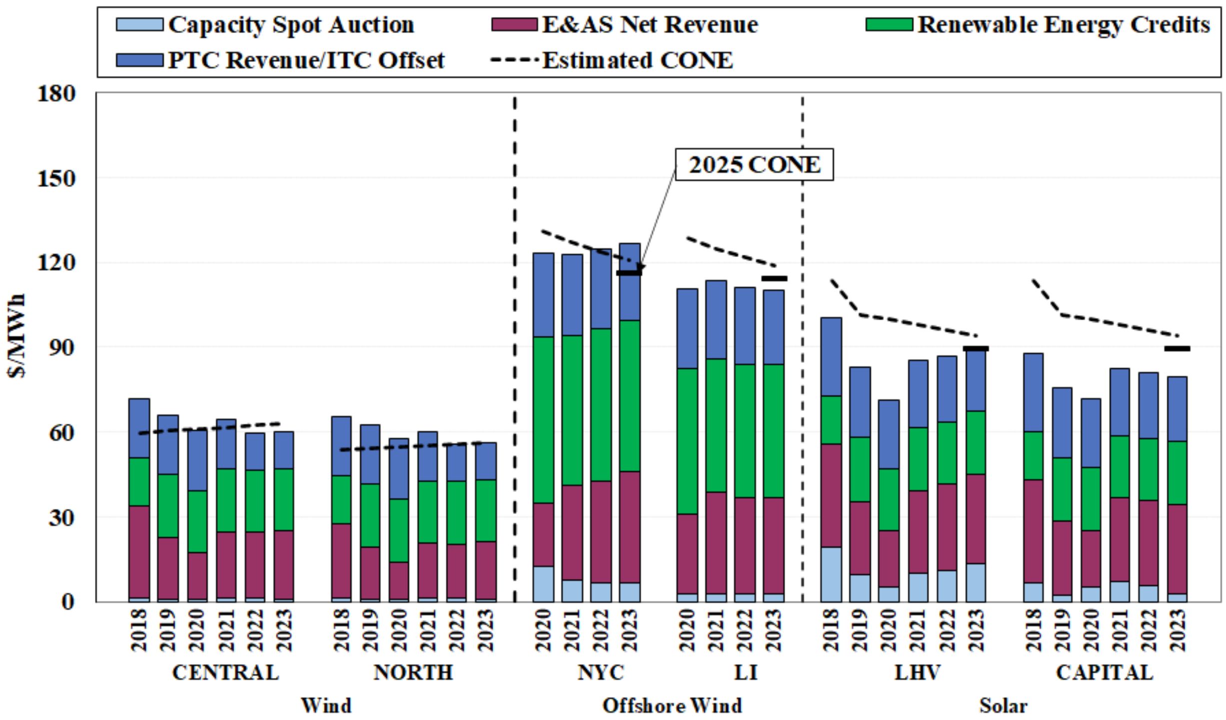
Assuming the operating and cost parameters shown in the table above, Figure A-124 shows the net revenues and the estimated CONE for each of the units during years 2018-2023. The CONE and net revenues of a unit in a given year correspond to those of a representative unit that commences operation in the same year.

We estimated the WACC for the projects as the weighted average of typical WACC for regulated and merchant entities in New York, with the contributions of REC revenues and the NYISO-market revenues to the project's NPV as weights.

Regional cost multiplier for solar PV and onshore wind are utilized from CES whitepaper, see here.

We assume construction lead time (i.e. time taken by a unit from commencement of its construction to commercial operation) of 1 year for solar PV plant and 3 years for onshore and offshore wind plants.

Figure A-124: Net Revenues of Solar, Onshore Wind and Offshore Wind Units
2018-2023



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 2020 relative to 2019, putting downward pressure on the estimated net revenues of renewables. Forward prices suggest an increase in the net revenues is expected from 2021-2023 relative to 2020.

- *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 2020 net revenues range are approximately 65 percent for a new solar PV project and 72 percent to 76 percent for a new onshore wind project.

- *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 2023.[442] However, the returns from individual projects would depend on several additional factors such as

442 Over 1,300 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.

contracted REC prices, resource potential and development costs at the project sites, and curtailment risk. Furthermore, as the value of PTC declines, the total net revenues for wind units may drop unless REC contracts or NYISO market revenues increase in value commensurately.

- *Incentives for Utility-scale Solar PV Units* – Estimated net revenues of the generic solar project are lower than the annualized CONE. However, solar project costs, based on the most recent NREL 2020 ATB mid case estimates, are expected to decline in nominal terms over the next several years.[443] Consequently, the net revenue of these resources in Lower Hudson Valley could be sufficient to meet its CONE in 2025 based on the assumed levels of RECs and energy forward prices.
    - Despite the calculated shortfall of net revenues relative to CONE, many solar projects continue to advance in the interconnection queue, the Class Year process, and recent solicitations for large-scale renewables by NYSERDA. Individual projects may benefit from favorable sites or interconnection points, stockpiled materials, or favorable contracts.[444]

- *Incentives for Offshore Wind Units* – Net revenues of offshore wind are estimated to be insufficient to recover their current costs. However, costs of developing offshore wind are expected to decline for projects with in-service dates in the mid-2020s, when the revenues are likely to be sufficient to meet the CONE in New York City.[445]
    - 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.
    - ORECs constitute a large share of offshore wind plant revenues. ORECs and federal ITC subsidies together contribute 72 percent of estimated net revenues in 2020.[446]

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443 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 2020 website, available here. 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 here.

444 Large amounts of solar projects have been selected in NYSERDA's bid-based Large-Scale Renewable solicitations. 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.

445 Currently contracted offshore wind projects are expected to enter into service in a similar timeframe.

446 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".

D. Impact of Market Enhancements on Investment Signals and Consumer Costs

Section XII 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, (b) the long-term investment signals of various resource types in several Zone J and Zone K locations, and (c) the potential impact on consumer prices and costs of adopting these recommendations. We model the net revenue impact of several recommended enhancements to real-time pricing for New York City and Long Island units.

NYISO is pursuing market design and implementation projects that would fully or partially address several of these recommendations. Table A-29 below indicates the ongoing NYISO effort that is most closely associated with each recommendation.

Table A-29: NYISO Projects Addressing Real Time Pricing Recommendations

Recommendation		2021 NYISO Project	Description / Status
2016-1	Compensate operating reserve units that provide congestion relief	Reserve Enhancements for Constrained Areas (RECA)	RECA would consider dynamic reserve modeling, reserve requirements in NYC load pockets, and compensation of reserve providers that help manage congestion. NYISO targets a 2021 Study Complete.
2017-1	Model local reserve requirements in NYC load pockets		
2017-2	Enhance operating reserve demand curves	Ancillary Services Shortage Pricing	NYISO filed tariff changes that partially addess this recommendation and targets Deployment in 2021.
2019-1	Model Long Island reserve requirement	N/A	Not a current Market Design project.
2018-1	Model Long Island transmission constraints	Operational changes	NYISO is considering operational changes to model a limited set of constraints.

We estimated the impact of the following four enhancements affecting New York City by adjusting the 2018-2020 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.[447]

[447] See Appendix V.B and discussion of recommendation 2016-1 in Section XII of the report.

- 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.[448]

- 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 $6.3/kW-year of net revenue from reserve shortages in southeast New York, reflecting both the changes proposed by NYISO in its Ancillary Services Shortage Pricing project and further recommended increases in the NYCA 30-minute reserve demand curve.[449]

- 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 2019 and 2020 energy and reserve prices:

- 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.

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448 See Section V.J of the Appendix and discussion of recommendation 2017-1 in Section XII of the report. We estimate that average operating reserve prices that would be necessary to represent the marginal costs of satisfying N-1-1 requirements in the day-ahead market to range from $1.99/MWh in most areas to as much as $3.26 in the Astoria West/Queensbridge load pocket in 2020. The estimated price adder for each day was applied to LBMPs and reserve prices in hour 16.

449 This value corresponds to (1) increased shortage prices at several reserve demand curve quantities proposed by NYISO in its Ancillary Services Shortage Pricing project, and (2) an increase in the maximum NYCA 30 minute reserve demand curve value to $2,750 from its current maximum of $750. We estimate that this value would be sufficient to retain reserves in NYISO during a simultaneous operating reserve shortage in ISO-NE. An annual net revenue value was estimated by multiplying historical hours of reserve shortage by the difference between the proposed ORDC value corresponding to the reserve shortage level in the same hour and the historical reserve shadow price in that hour.

- 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 $6.3/kW-year of net revenue from reserve shortages in southeast New York and Long Island as described above.

Table A-30: Assumptions for Operating Characteristics of Grid-scale Storage Units

The technologies we considered for this analysis and their assumed operating characteristics are as follows:[450]

- New Frame CT (7HA.02), Existing GT-30, and Existing ST Units – The operating characteristics and CONE/GFCs for these units are the same as in Subsection A.

- 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 determined by co-optimizing the unit's energy and reserve revenues using the day-ahead market prices. We limit the injections and withdrawals to one cycle per day. The costs and operating characteristics of this unit are summarized above in Table A-30.

Table A-30: Operating Parameters and CONE of Storage Unit[451]

Characteristics	Storage
Gross CONE (2020$/kW-yr)	$241
Technology	Li-ion Battery
Service Life (Years)	20
Reserve Selling Capability	10-min spin
Roundtrip Efficiency	85%
EFORd	2%
Capacity Value	90%

Figure A-125: 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

450 The CONE estimates for new technologies assume units would commence operations in 2020.

451 Cost assumptions are sourced from the 2020 NYISO ICAP Demand Curve Reset study. See *Independent Consultant Study to Establish New York ICAP Demand Curve Parameters for the 2021/2022 through 2024/2025 Capability Years – Final Report*.

conditions modeled in the ICAP demand curve reset.[452] Figure A-125 shows the incremental impact of each recommendation on the change in net revenues of the 7HA.02 CT 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.

Figure A-125: Impact of Price Enhancements on Net Revenues of NYC Demand Curve
At Level of Excess Conditions

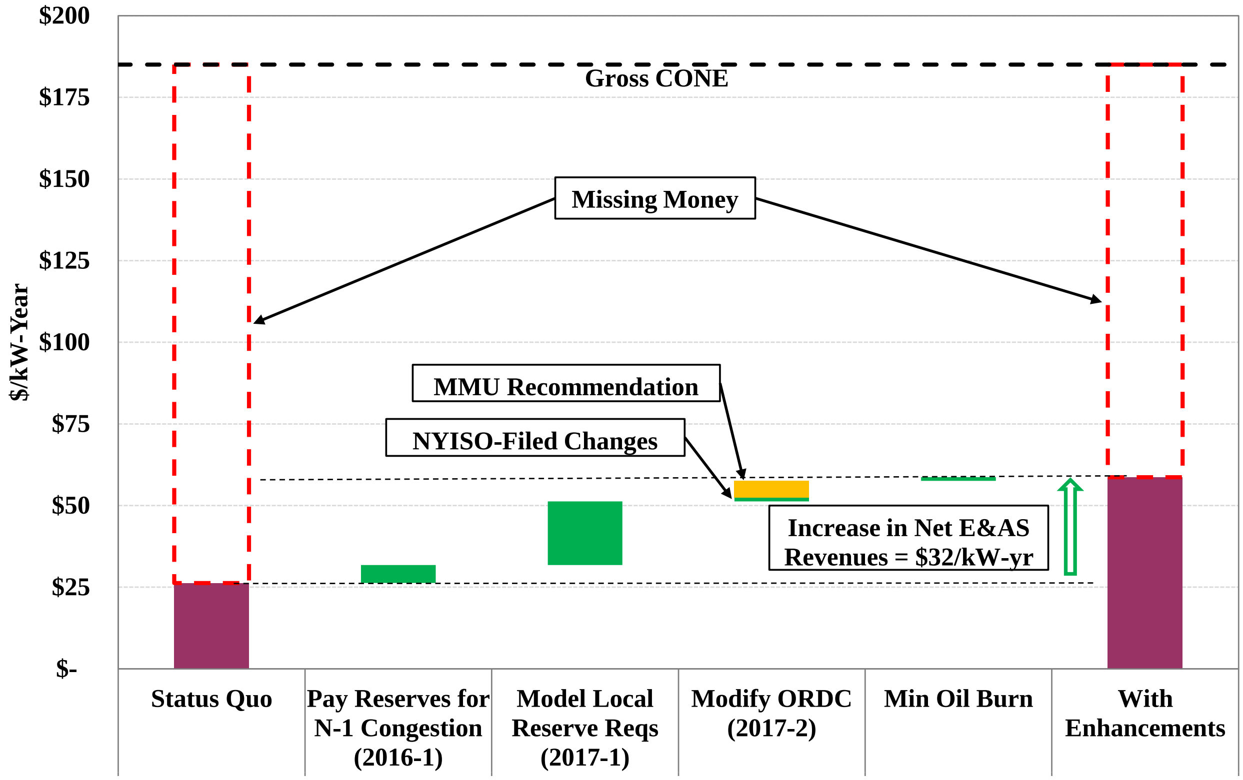


Figure A-126 to Figure A-129: Impacts of Real Time Pricing Enhancements on New York City Net Revenues

Figure A-126 through Figure A-129 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 show the shortfall in net revenues relative to the CONE/GFC for each technology.

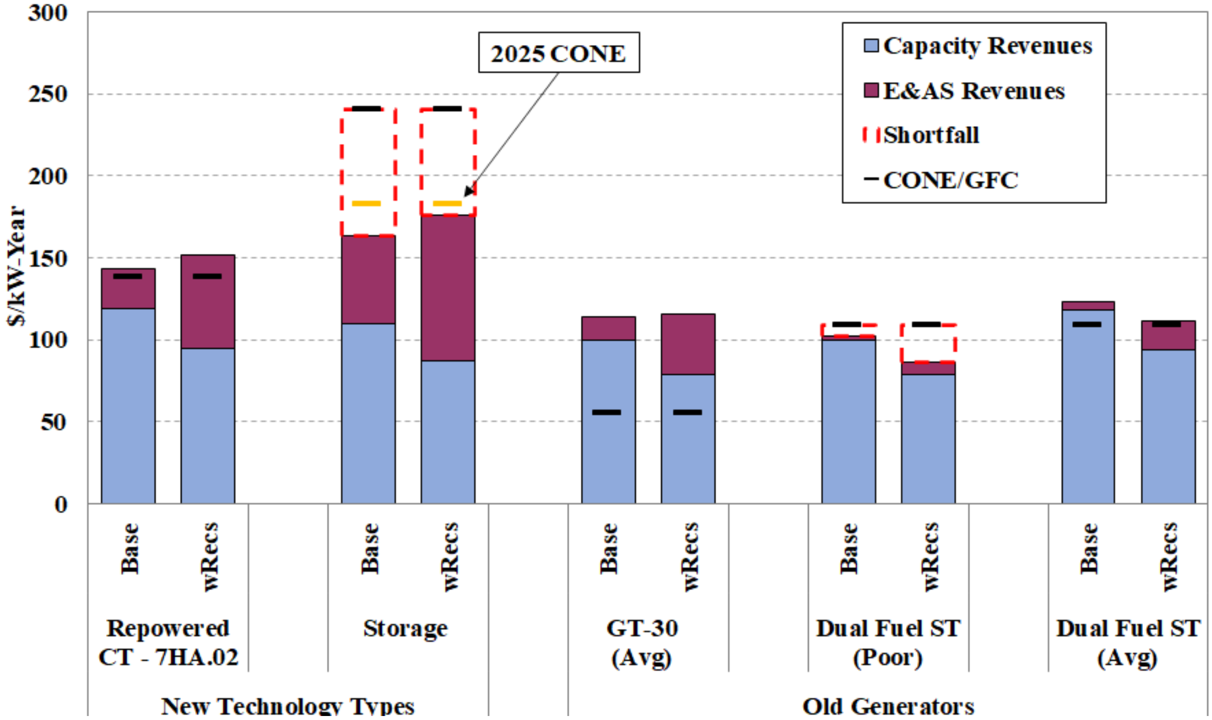
Capacity revenues in each case reflect prices at the Default Net CONE, which is calculated as 75 percent of the net CONE of the Demand Curve unit. The Default Net CONE is the price that

452 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 2020 report *Independent Consultant Study to Establish New York ICAP Demand Curve Parameters for the 2021/2022 through 2024/2025 Capability Years – Final Report*.

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 proposed Tariff provisions which will allow Public Policy Resources ("PPRs") to be tested under the Part A test ahead of non-PPR entrants.[453] Hence, the NYISO's proposed rules would enable PPRs to avoid mitigation as long as sufficient quantity of existing capacity exits the market. Therefore, if the NYISO's proposed rules are accepted, the economics of new and existing units at the Part A threshold will be relevant for facilitating the entry of PPRs.

Figure A-126: Impact of Pricing Enhancements on Net Revenues - New York City

At Part A Threshold



453 See FERC Docket ER20-1718.

Figure A-127: Impact of Pricing Enhancements on Net Revenues – NYC Load Pocket #1
At Part A Threshold

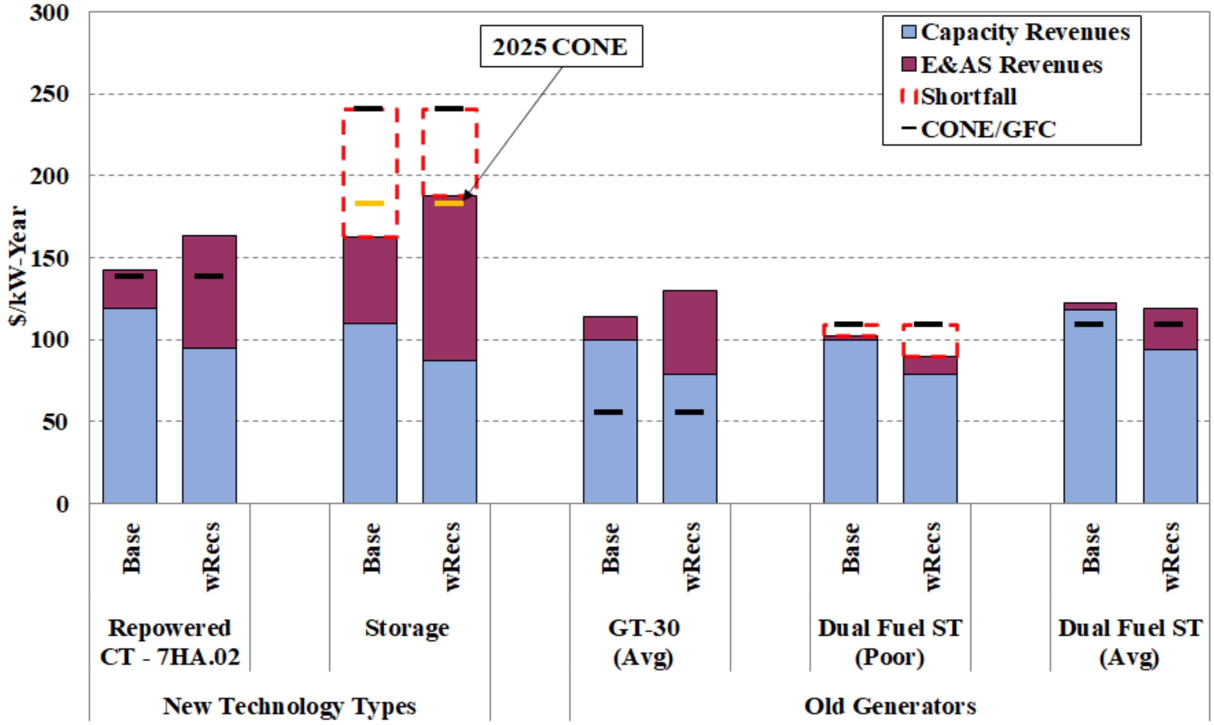


Figure A-128: Impact of Pricing Enhancements on Net Revenues – NYC Load Pocket #2
At Part A Threshold

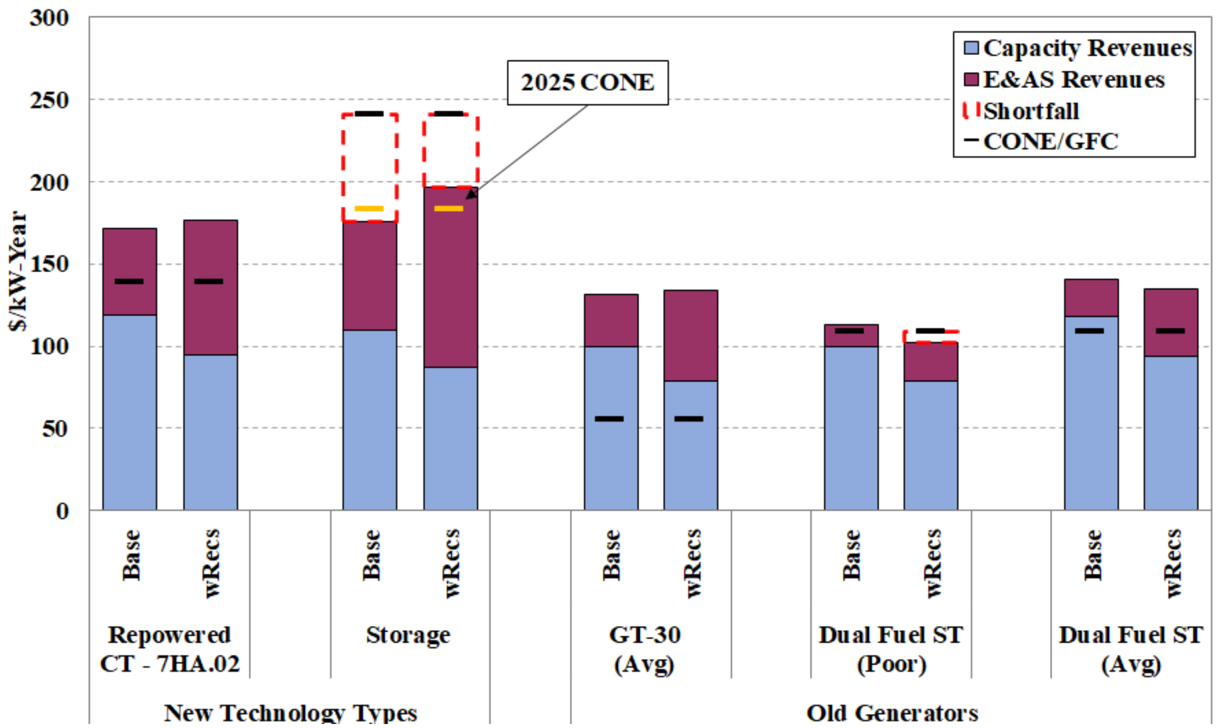


Figure A-129: Impact of Pricing Enhancements on Net Revenues – NYC 345 kV
At Part A Threshold

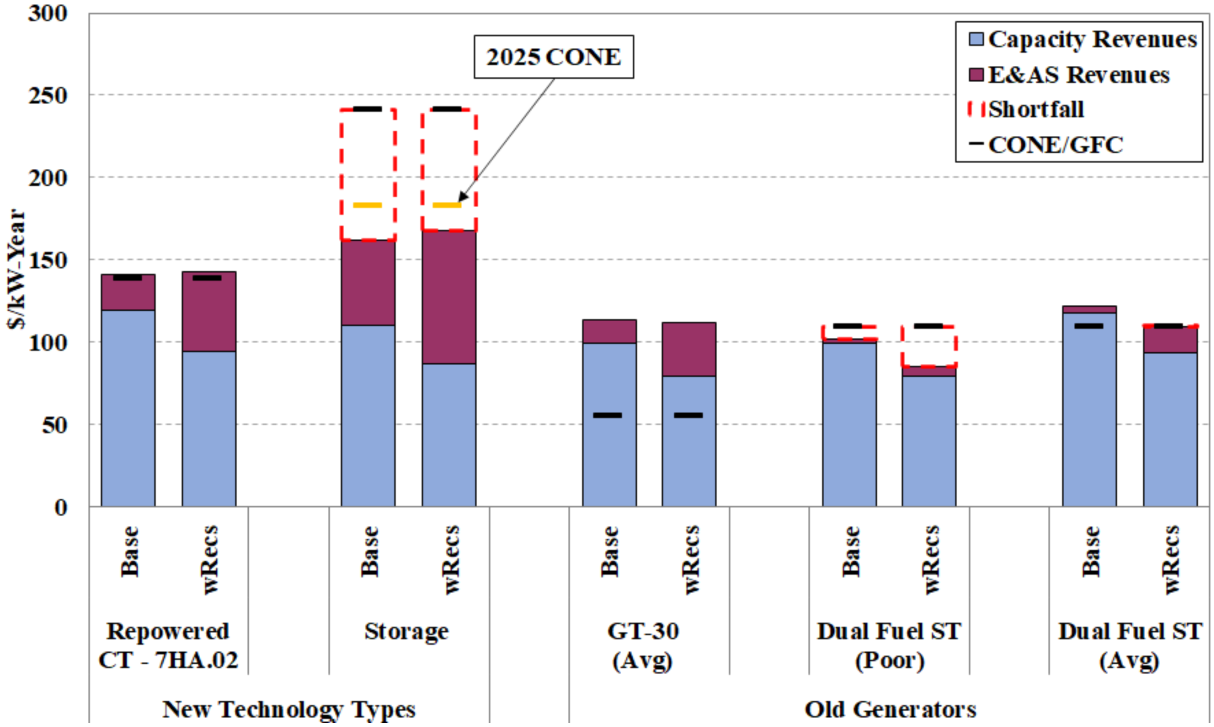


Figure A-130: Impacts of Pricing Enhancements on Consumer Costs in New York City

The proposed pricing enhancements would result in higher total energy and reserve market payments while reducing other market payments, including capacity payments and uplift. Figure A-130 shows the estimated impact that the proposed enhancements would have had on New York City consumer costs using price data from the period 2018 to 2020. Our assumptions and methodology for estimating these costs are as following:

- *Energy Payments* – Includes higher energy prices due to modeling of load pocket reserve requirements (2017-1) and higher shortage pricing values (2017-2).
  - We estimated the increase in LBMPs in each load pocket multiplied by the day-ahead forecasted demand for the corresponding portion of the city.
  - Higher payments due to enhanced shortage pricing are estimated based on the recommended price increase during historical hours of NYCA 30-minute reserve shortages multiplied by Zone J load in those hours.
- *Reserve Payments* – Includes higher reserve prices due to modeling of load pocket reserve requirements, higher shortage pricing values, and payments to reserve providers for congestion relief.
  - The weighted average price increase from modeling of local reserve requirements and the price increase from enhanced shortage pricing are multiplied by 1,000 MW, the total reserve requirement in Zone J.

- We also multiplied the estimated weighted average increase in reserve prices at locations where 10-minute reserve providers can help relieve N-1 transmission congestion by 500 MW, the 10-minute reserve requirement in Zone J.

- *Installed Capacity Savings* – Includes lower capacity prices due to a higher energy and ancillary services offset for the ICAP Demand Curve unit, as a result of all of the recommendations discussed in this section.[454] Capacity savings were valued at the level of excess assumed in the ICAP demand curves.

- *Uplift Savings* – We assumed savings of $23 million, equivalent to annual average BPCG payments made to generators that were committed for local N-1-1 needs in New York City.[455] These payments would be substantially reduced or eliminated by the proposed modeling of local reserve requirements in NYC load pockets.

- *Transmission Congestion Contract Savings* – We estimated additional TCC revenues due to the increase in New York City energy prices, which are assumed to be passed through to consumers. Additional TCC revenues are calculated by multiplying the average increase in Zone J energy prices by average transmission flows into Zone J.

- *Energy Storage Contact Costs* – The NYSPSC established a mandate for Con Edison to contract with 300 MW of bulk energy storage resources in-service by 2023. The proposed pricing enhancements would increase the NYISO market net revenues of energy storage resources in high-value load pockets of the Con Edison system (see Figure A-127 and Figure A-128), reducing the out-of-market contract payment that would be required for Con Edison to attract these resources. We assume that half of the contracted 300 MW of storage is located in each of the NYC load pockets analyzed, and treat their estimated increase in net revenues ($15/kW-year in Load Pocket 1 and $8/kW-year in Load Pocket 2) as reduced contract payments paid by consumers.

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454 See Figure A-125. Note that the impact of the proposed pricing enhancements are assumed to be fully reflected in the net E&AS revenues of the demand curve unit during the period analyzed.

455 This value represents an average of day-ahead DAM Local BPCG uplift payments between 2018 and 2020. See Figure A-103. This value reflects uplift under historical conditions and not at the level of excess assumed in the demand curve reset, and therefore is likely a conservative estimate.

Figure A-130: Impact of Price Enhancements on Consumer Costs in New York City
At Level of Excess Conditions

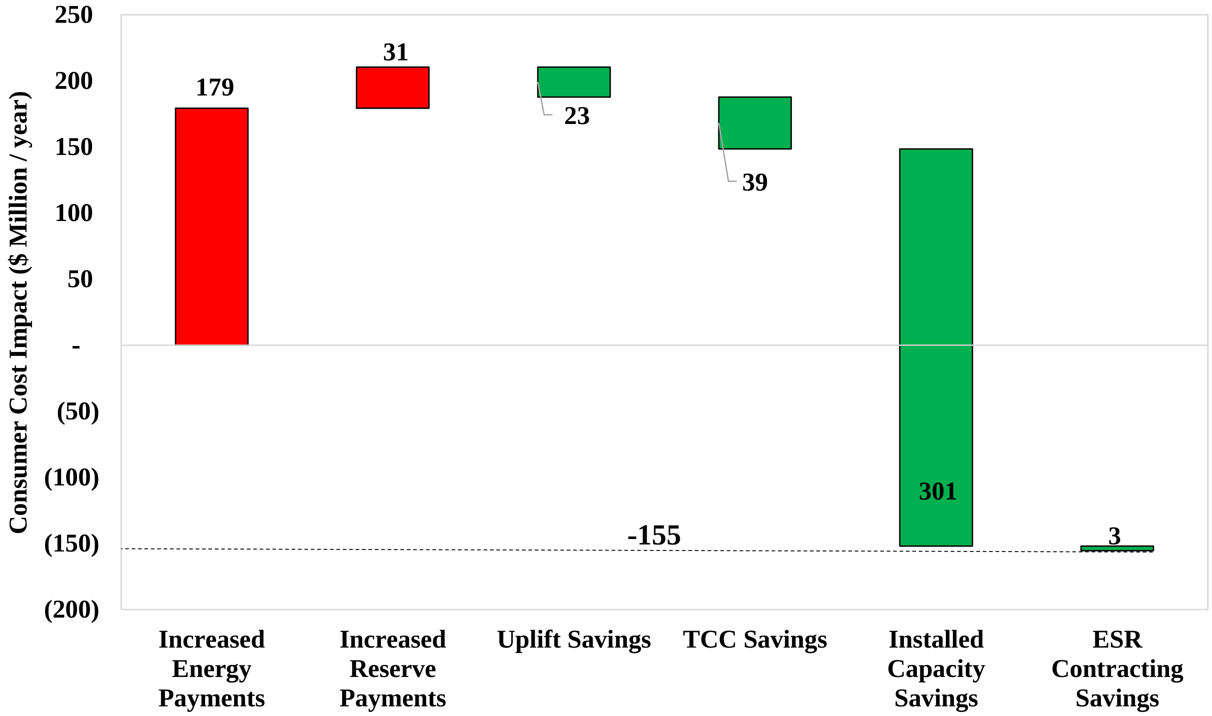


Figure A-131: Impacts of Real Time Pricing Enhancements on Net Revenues of Long Island Demand Curve unit under Long-term Equilibrium Conditions

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-131 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-131: Impact of Price Enhancements on Net Revenues of Zone K Demand Curve
At Level of Excess Conditions

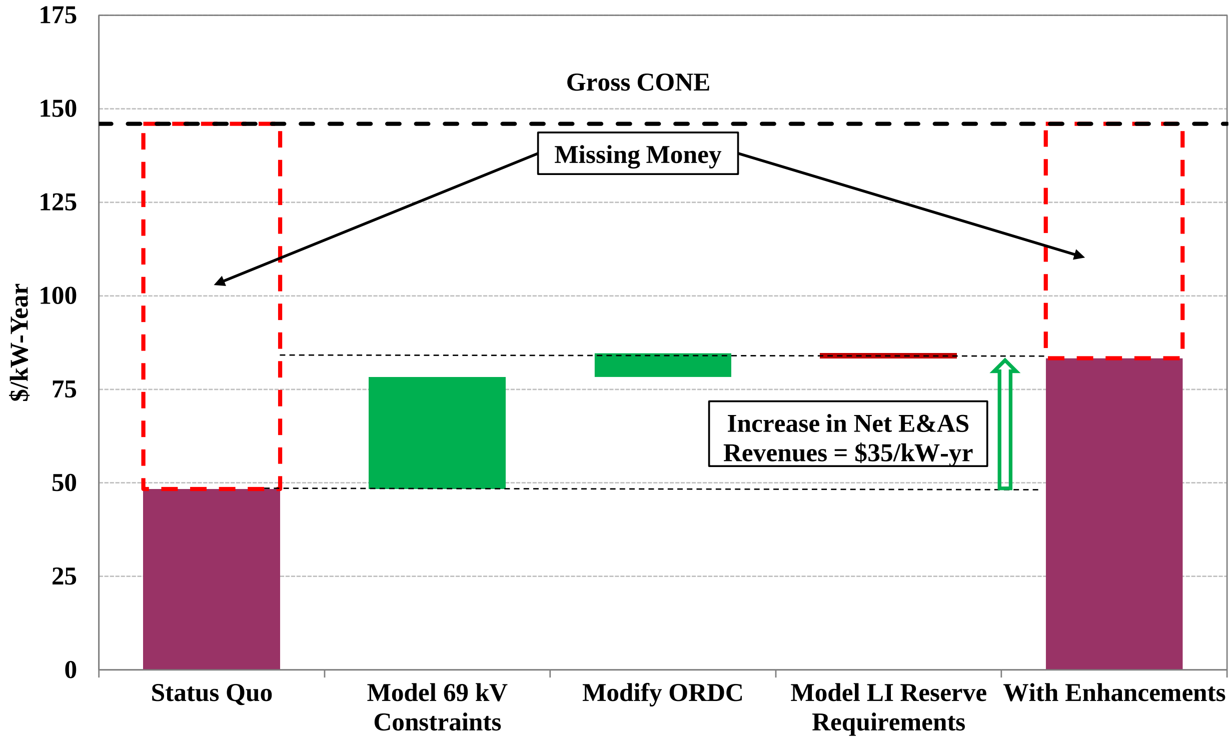
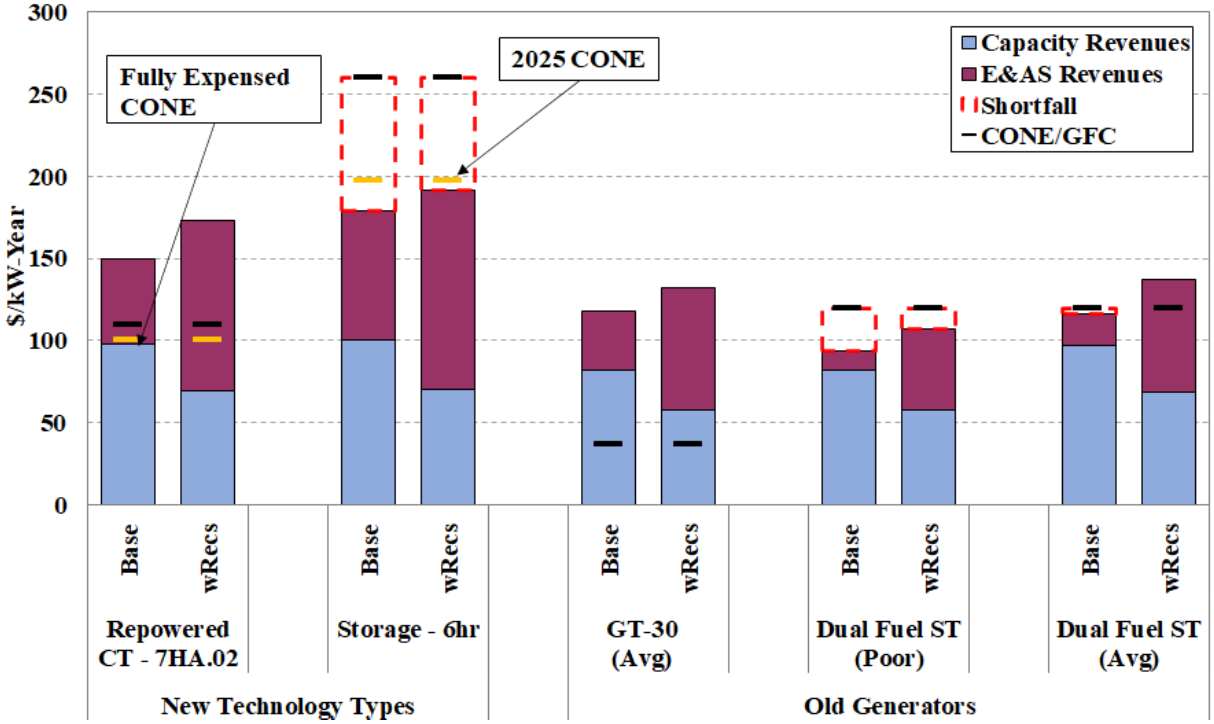


Figure A-132: Impacts of Real Time Pricing Enhancements on Net Revenues

Figure A-132 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 2019 and 2020 and the LOE adjustment factors from the most recent ICAP Demand Curve reset study.

Figure A-132: 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 $32/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 60 percent increase in the E&AS revenues for the demand curve unit.
  - Increasing operating reserve shortage prices to levels that would retain supply during regional shortage events (Recommendation 2017-2) would increase E&AS revenues of the demand curve unit by approximately $6.3/kW-year. Of this amount, $1.2 (19 percent) is provided by changes to the structure of reserve demand curves already proposed by NYISO under its Ancillary Services Shortage Pricing project, while $5.1 (81 percent) is provided by our recommendation that the maximum NYCA 30 minute reserve price be increased in addition to NYISO's proposal.
- *Incentives for Resources at Representative New York City Node* – At the assumed surplus level, our simulations for resources at the representative New York City node indicate that E&AS pricing enhancements are likely to have a positive or neutral impact on the net revenues of newer, more flexible units (Figure A-126). 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 offsets 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 net E&AS revenues while reducing capacity revenues, with a neutral or slightly positive overall impact.
- 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 which largely depend on capacity revenues, and would receive lower total net revenues.[456]

- *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-127 through Figure A-129, 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. Additionally, a repowered 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 due to decrease in capacity prices, 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. Hence, it is generally more efficient to compensate resources through the energy and reserve markets than through capacity markets.

- *Impact of Pricing Enhancements on Consumer Costs in New York City* - Under the conditions analyzed, the proposed pricing enhancements would have reduced annual

456 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.

consumer costs in New York City by an estimated $173 million. Higher payments to energy and reserve providers were offset mostly by savings in capacity payments, and to a lesser extent by savings in uplift costs, TCCs and energy storage contract payments.

- Reduced capacity market payments are the largest source of consumer savings. This is because the capacity market demand curves are reduced based on the increase in E&AS revenues of the demand curve unit. Consequently, as shown in Figures Figure A-127 through Figure A-129, many existing units that are less valuable to the system would see a reduction in net revenues.
- Increases in consumer costs primarily take the form of higher energy payments. This includes higher LBMPs in load pockets where local reserve requirements are modeled, and higher LBMPs due to increased operating reserve demand curve levels during shortage hours. The increase in consumer payments for reserves is smaller because the quantity of units that receive reserve revenues is much smaller than total energy market demand.
- This estimate of the impact on consumer costs does not account for changes in the resource mix over time due to incentives created by the pricing enhancements. The enhancements would favor resources that are flexible and are located in high-value locations. Over time this could lead to investment in resources with these characteristics that reduces overall production costs in a market with high renewable penetration. Hence, our analysis likely understates the savings resulting from the proposed pricing enhancements.

- *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.
  - Our recommendation of modeling transmission constraints on the 69 kV network that are currently managed by OOM actions (i.e. 2018-1) accounted for most (approximately 75 percent) 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 $29 to $53 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. 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. [457] 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.

[457] 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.

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 of the five programs allow NYISO to curtail loads in real-time for reliability reasons:

- Emergency Demand Response Program ("EDRP") – These resources are paid the higher of $500/MWh or the real-time clearing price. There are no consequences for enrolled EDRP resources that fail to curtail.[458]

- 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.[459]

- 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.

The other two are economic demand response programs that 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.[460] 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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458 Resources participate in EDRP through Curtailment Service Providers ("CSPs"), which serve as the interface between the NYISO and resources.

459 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.

460 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, it is important to develop programs to provide efficient incentives to demand response resources and facilitate their participation in the real-time market.

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:

- Meter Service Entity ("MSE") for DER – The MSE rules went into effect in May 2020, which authorize third party metering that provides greater flexibility to consumers and retail load serving entities for demand side participation.

- Dual Participation ("DP") – The DP rules went into effect in May 2020, which allow resources that provide wholesale market services to also provide retail market services.

- DER Participation Model – Scheduled for software development in 2021 and deployment in 2022. – 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.

This section evaluates the performance of the existing programs in 2020 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.

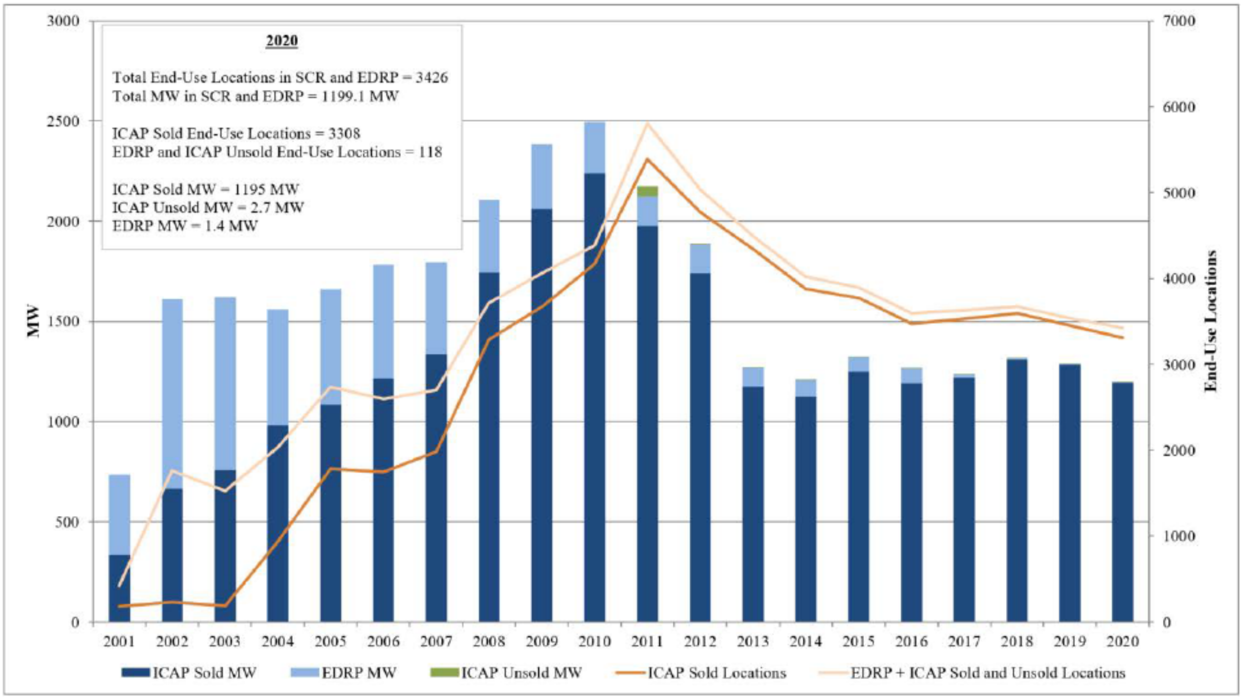
A. Reliability Demand Response Programs

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-133: Registration in NYISO Demand Response Reliability Programs

Figure A-133 summarizes registration in two of the reliability programs at the end of each summer from 2001 to 2020 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-133: Registration in NYISO Demand Response Reliability Programs [461]
2001 – 2020



B. Economic Demand Response Programs

The NYISO offers two economic demand response programs.[462] First, 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.[463] 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.

Second, the DSASP program allows demand response resources to provide ancillary services. This program has the potential to increase the amount of resources that provide operating

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461 This figure is excerpted from the compliance filing report to FERC: *NYISO 2020 Annual Report on Demand Response Programs*, January 13, 2021.

462 In addition, there is a Mandatory Hourly Pricing ("MHP") program administered at the retail load level, which is currently regulated under the New York Public Service Commission. This 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. 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.

463 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.

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.

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.

Key Observations: Demand Response Programs

- In 2020, total registration in the EDRP and SCR programs included 3,426 end-use locations enrolled, providing a total of 1,199 MW of demand response capability.

- SCR resources accounted for nearly all of the total enrolled MWs in the reliability-based program in recent years, as this allowed them to earn revenue from the capacity market.
- In the Summer 2020 Capability Period, market-cleared SCRs contributed to resource adequacy by satisfying:
  - 4.6 percent of the UCAP requirement for New York City;
  - 3.9 percent of the UCAP requirement for the G-J Locality;
  - 0.8 percent of the UCAP requirement for Long Island; and
  - 3.3 percent of the UCAP requirement for NYCA.

- No resources have participated in the DADRP program since December 2010.
  - Given that loads may hedge with virtual transactions that are very similar to DADRP schedules, the value of this program is doubtful.
- Two DSASP resources in Upstate New York actively participated in the market in 2020 as providers of operating reserves.
  - On average, the two resources collectively provided less than 60 MW of 10-minute spinning reserves in 2020, satisfying less than 9 percent of the NYCA 10-minute spinning reserve requirement.
- In 2020, the NYISO did not activate the EDRP or ICAP/SCR resources for reliability, therefore, the performance of DR calls is not evaluated in this report. However,
  - The TDRP was activated on five days in July (6, 7, 20, 27, & 28) in response to Transmission Owner requests. These responses were voluntary and the scarcity pricing was not applicable.
  - Various amount of DR resources in local Utility programs were activated on 21 days in 2020.
    - The deployment exceeded 100 MW on eight of these days, roughly half of which was for peak-shaving and distribution system security in New York City and the other half for peak-shaving outside New York City.
    - Section V.I of the Appendix evaluates the utility DR calls on several days.