2021 State of the Market Report For the New York ISO Markets

POTOMAC ECONOMICS

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

Market Monitoring Unit
for the New York ISO

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EXECUTIVE SUMMARY

As the NYISO's Market Monitor Unit ("MMU"), our Core Functions include reporting on market outcomes, evaluating the competitiveness of the wholesale electricity markets, identifying market flaws, and recommending improvements to the market design. We also evaluate the market power mitigation rules, which are designed to limit anticompetitive conduct that would erode the benefits of the competitive markets. The 2021 State of the Market Report presents our assessment of the performance of the wholesale electricity markets administered by the NYISO in 2021. 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.

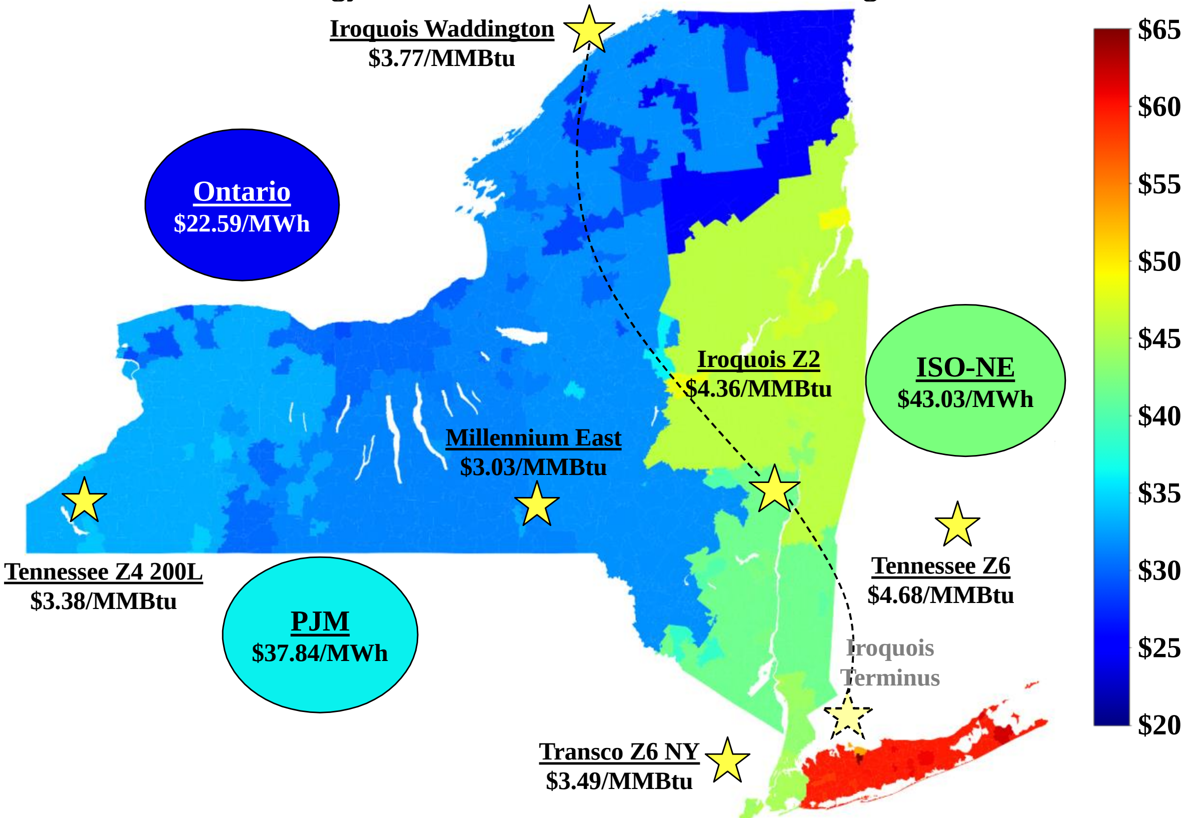
Market Highlights in 2021

The NYISO markets performed competitively in 2021 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 and capacity 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 rose by more than 100 percent across the state in 2021 from very low levels in 2020 to the highest levels of the past five years (outside of peak winter conditions). Natural gas prices increased as rising LNG exports outpaced the growth in domestic production. Average load levels recovered slightly in 2021 from the very low levels in 2020, but load continues a general downward trend since 2013. Peak load exhibited a similar pattern, increasing slightly from 2020 but having fallen over the past decade. (See Sections II.C and II.D for details).

Real-Time Energy Prices, Natural Gas Prices, and Congestion in 2021



Energy Prices and Transmission Congestion

Real-time prices varied from an average of $24.10 per MWh in the North Zone to $62.24 per MWh in Long Island in 2021 because of the effects of transmission congestion and losses. (See Section II.A) Average energy prices rose substantially from 2020 to 2021, up 72 to 78 percent in Western New York and 92 to 104 percent in Eastern New York. The increases across the system were driven primarily by higher natural gas prices. The larger increase in Eastern New York was mostly attributable to more severe transmission bottlenecks across the Central-East interface because of lengthy transmission outages taken to facilitate several Public Policy Transmission Projects and the retirements of Indian Point nuclear units. In addition, Long Island experienced lengthy transmission outages on both of its tie lines with upstate regions, leading to abnormally high levels of congestion and elevated energy prices on Long Island.

Consequently, congestion revenues collected in the day-ahead market rose 86 percent from 2020, totaling $551 million in 2021. (See Section VI.A) The following corridors accounted for most of the congestion in 2021:

- Central-East Interface – 56 percent
- Long Island – 12 percent

- West Zone (flowing east) – 9 percent
- North to Central New York – 6 percent
- New York City – 6 percent

Capacity Market

Fluctuations in the statewide and local capacity requirements led to large changes in capacity prices from 2020 to 2021. The statewide requirement increased by over 600 MW and was a key driver of price increases in the "Rest of State" region (i.e., Zones A-F) and the Lower Hudson Valley (i.e., Zones GHI). The local requirements decreased by more than 900 MW in New York City and 600 MW in the G-J Locality, roughly 30 percent of which for NYC was due to a lower load forecast. Overall, the large changes in the capacity margin requirements (i.e., the IRM and LCRs) were the main driver of capacity price changes from the prior year. (See Section VII.A)

The prices in 2021 reflect changes in the surplus capacity margins, which resulted primarily from the changes in requirements. The surplus capacity margin in New York City for the 2021/22 capability year was very high (~14 percent), up from just 4 percent in the previous capability year, leading New York City capacity prices to fall sharply. Consequently, the going forward cost ("GFC") of a well-maintained steam turbine likely exceeded its net revenues in New York City and the Lower Hudson Valley. (See Section II.B) However, capacity prices are expected to increase as older conventional generators retire over the next three years.

Investment Incentives for Renewable Generation and Energy Storage

The NYISO market provides price signals that motivate firms to invest in new resources, retire older units, and/or maintain their existing generating units. Historically, NYISO has seen entry of efficient fossil generators driven by wholesale market revenues. In recent years, investment has shifted to renewable resources. New York State has ambitious clean energy goals under the Climate Leadership and Community Protection Act, including requirements for 70 percent renewable electricity by 2030 and 100 percent zero emissions electricity by 2040. Meeting these mandates will require unprecedented levels of investment in the power sector.

Wholesale markets are critical for coordinating investment in new resources even when state policy is the main driver. There are many possible combinations of projects that can satisfy state goals, some more cost-effective than others. Competitive wholesale markets motivate investors to pursue the projects, technologies, and locations that meet the needs of the system most efficiently. Such projects earn higher market revenues and are therefore more likely to be selected in state solicitations for clean resources, allowing clean energy targets to be met at the lowest total cost to ratepayers. The New York Public Service Commission has acknowledged the importance of the NYISO's wholesale market signals by adopting contractual incentive mechanisms – such as fixed and Index RECs – that expose developers to market risks.

In Section III.A of this report, we analyze incentives for investment in several technologies at recent market price levels. In general, market conditions have not supported new investment in recent years because of relatively low prices and moderate-to-high capacity surpluses. However, the incentives vary by technology:

- *Renewable generation* – At recent market prices and costs (including state and federal incentives), we estimate that revenues justify investment in land-based wind. This is consistent with current trends that nearly all recent investment has been in land-based wind, although other considerations (such as permitting and siting) may limit the extent of development. Other technologies, including solar and offshore wind, do not appear to be economic under prevailing conditions. This may explain why most such projects under contract with the State are significantly delayed. However, the costs of these technologies are expected to fall over the long term. State and federal incentives account for the majority of revenues for all types of renewable generation, although wholesale energy and capacity revenues make up a significant share.
- *Energy storage* – We find that market revenues are currently below levels that would justify investment in 4-hour and 6-hour batteries. This is not surprising because the conditions that would make battery projects valuable – namely, high levels of intermittent renewable penetration and/or high capacity prices – are not yet present in NYISO. Increased renewable deployment, growing requirements for ancillary services, and retirement of conventional generators will make storage more economic over time.

In Section III.B, we evaluate whether NYISO's markets are designed to accurately recognize and reward the wholesale services that energy storage provides, including integrating renewables. It is commonly expected that larger quantities of storage than the CLCPA's 3-GW target could efficiently help to meet state goals over the long term – but the optimal quantity, duration, location and timing of storage projects is uncertain and largely depends on the amount and type of renewable capacity on the grid. We find the following:

- NYISO's energy markets will compensate storage that alleviates curtailment of renewable generation. When renewable resources are curtailed, LBMPs are set at negative levels equivalent to the cost of the renewables' foregone REC payment. Batteries that reduce curtailment of renewables by charging at these times are paid for the energy they absorb. Hence, our analysis shows that at any location where renewables are curtailed, storage revenues will increase, creating strong incentives for storage developers to anticipate or respond to renewable integration needs even if they do not receive state and federal incentives.
- Under NYISO's recently approved marginal capacity accreditation rules, capacity revenues of storage units will reflect that they complement the availability of intermittent resources. As deployment of renewables rises, the amount of storage that can receive high capacity value ratings will naturally tend to grow. Additionally, higher levels of

intermittent penetration will lead to more frequent transitory shortages as its output fluctuates, which can significantly increase revenues for storage resources. This should facilitate storage development that efficiently complements the renewable fleet.

- Ancillary services revenues are expected to play a large role in promoting storage investment. However, several aspects of the current markets under-value flexible resources. We make recommendations in this report to address these shortcomings and appropriately value the growing need for flexible resources. (See Recommendations #2015-16, #2016-1, #2017-1, #2017-2, #2019-1, and #2021-2)

With the enhancements recommended in this report, the NYISO markets will provide efficient price signals for storage to enter the market when it can facilitate integration of renewable energy. Importantly, market driven storage investment could avoid the need for arbitrary contracting mandates, which run the risk of procuring excessive or sub-optimal projects that provide little marginal benefit while requiring large contract payments.

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 they 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. For example, in recent years we have observed bottlenecks going into zones A/B from Central New York and from Staten Island to the rest of New York City that are not represented by the current capacity zone configuration. The lack of locational signals is an inefficient barrier to entry for new resources, which are required to pay for transmission upgrades to receive capacity rights if they are not fully deliverable throughout their entire capacity region. Offshore wind and battery projects in Long Island were recently assigned costly deliverability upgrades that are not required of incumbents that are limited by the same constraints.
- *Problems with LCR-setting process* – Locational capacity requirements are set using the "LCR Optimizer" which produces results that are inefficient and excessively volatile. The LCR Optimizer uses a flawed objective function and is misaligned with the process to establish the Installed Reserve Margin. We show that the objective function – which is designed to minimize consumer costs rather than investment costs – is overly sensitive to small changes in inputs and leads to volatility in the LCRs and capacity prices.

- *Some types of capacity are under or over-compensated* – The current market design is not equipped to adjust capacity payments to account for the growing differentiation of availability among resource types, including intermittent renewables, energy storage, and natural gas-dependent generation. Efficient capacity compensation will be critical for guiding decisions about new development projects and which conventional generators to retire. Although an efficient framework was recently approved for establishing generators' capacity credit based on their marginal impact on reliability, significant modeling improvements will be needed to implement this approach for all resources.

To address these and other issues with the capacity market, we recommend improvements:

Locational Capacity-Pricing Enhancements. It is not possible for the NYISO to address the concerns discussed above in a piecemeal fashion. Hence, we recommend a comprehensive approach ("C-LMP") which would efficiently set locational capacity prices and eliminate problems caused by the LCR Optimizer. C-LMP would: (a) produce more granular prices that are better aligned with NYISO's planning criteria, (b) be more adaptable to changes in resource mix and transmission flows, (c) remove unnecessary barriers to new entry in the interconnection process, (d) be less burdensome for the NYISO to administer, and (e) reduce the overall costs of maintaining reliability. (See Section VII.D and Recommendation #2013-1c)

ICAP Accreditation Improvements. Capacity accreditation refers to the fraction of a resource's installed capacity that can be sold in the capacity market. It is intended to reflect the likelihood that the resource will be available when needed for reliability. In early 2022, the NYISO made tariff revisions to enhance how it establishes resources' capacity credit ratings. NYISO proposes to annually accredit each resource class based on its marginal contribution to reliability (e.g., its expected availability during hours when load shedding is most likely).

These changes are a major improvement to the capacity market and will improve the efficiency of investment and retirement signals. However, enhancements are needed to how certain resource types are represented in NYISO's resource adequacy model when determining capacity value to ensure that resulting values are accurate. These include gas-only generators without backup fuel, resources whose availability is correlated with load, energy-limited resources, and inflexible generators.

Improving the valuation and accreditation of these various classes of resources will be necessary to ensure that the capacity market continues to effectively support the reliability of the system over the long term. Hence, we recommend that the NYISO improve capacity modeling and accreditation for these resource types. (See Section VII.E and Recommendation #2021-4).

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 the supply of fuel-secure generation declines.

Incentives for Operating Reserve Providers

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 2021, this allowed additional flows of:

- 18 to 31 percent (of the facility seasonal LTE rating) on the 345 kV transmission lines from upstate New York into New York City; and
- 5 to 28 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 not only inefficient scheduling and pricing in the real-time market but also 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 three years, efficient market incentives are needed to attract new investment in flexible 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 V.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 roughly 800 MW of duct-firing capacity to the State. This additional output can be offered into the energy market as a portion of the dispatchable range of the unit. However, a large portion of the duct-firing capacity was either not offered or was offered but unable to follow 5-minute instructions in 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 three years. (See Section V.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 broadly 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 V.A and Recommendation #2015-16)

Second, the operating reserve demand curves are set well below the levels that would adequately incent market participants to take actions to preserve reliability during critical conditions. Although the NYISO revised some reserve demand curves in the summer 2021, the maximum demand curve value is still far below: (a) the cost of out-of-market actions to maintain reserves when neighboring control areas also experience reserve shortages; and (b) the reliability value of reserves in reducing the likelihood of load shedding during deep reserve shortages.

The understated shortage pricing is particularly 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 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 during tight regional conditions, negatively affecting NYISO’s reliability as energy is drawn to neighboring markets even when shortages in NYISO are much deeper. The need for resources to be responsive to emergency conditions in real time will become increasingly important as the entry of intermittent renewables and retirement of conventional generators is likely to increase net load forecast uncertainty and create new operational challenges.

Therefore, we continue to recommend the NYISO consider rule changes to help maintain reliability and provide appropriate incentives during shortage 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. (See Section V.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 resources or ramping ability to reduce the flows. NYISO experienced such localized shortages in roughly 9 percent of intervals in 2021, our evaluation of which indicates that the constraint "shadow prices" that set the locational congestion prices in these intervals were 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 will significantly improve the current GTDC. (See Section V.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 assumes that offline GTs are able to respond to dispatch instructions even though they actually cannot. This disconnect 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) on the transmission constraints, compelling the 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 V.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 2021, 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 (~$8 per MWh) between the markets to profit from the transactions, and they offer much lower quantities.

- The NYISO's export fees are very high and may reduce the revenues received from CTS transactions – just $0.8 million in 2021. 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 significantly reducing) transaction fees and uplift charges between PJM and NYISO. (See Section VIII.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 VIII.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 2021, the operation of these lines (in accordance with the wheeling agreements) ***increased*** (a) production costs by an estimated $10 million; (b) CO_2 emissions by an estimated 426 thousand tons; and (c) NOx emissions by an estimated 606 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 V.F and Recommendation #2012-8.)

Out-of-Market Actions

Guarantee payments to generators rose by 28 percent in 2021 to $54 million. The increase was driven primarily by higher natural gas prices that increased the commitment cost of gas-fired resources, but it was partially offset by lower levels of out-of-market commitments and dispatches. (See Section V.G)

New York City

Although OOM commitments in New York City fell 19 percent from 2020 to 2021 because of several procedural enhancements to commit resources for the N-1-1-0 requirements in the load pockets, they still accounted for 80 percent of all reliability commitments. Over $19 million of guarantee payment uplift accrued on units that were committed for this purpose in 2021. 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. We have recommended the NYISO model local reserve requirements to satisfy these N-1-1-0 needs, which should provide more transparent and efficient price signals (See Section V.G and Recommendation #2017-1)

NYISO is considering modeling New York City load pockets as part of its 2022 *Dynamic Reserves* project, and the prototype analyzed by NYISO in the RECA Study would allow those requirements to be set dynamically. This will become particularly important when offshore wind is added to New York City because it will allow the NYISO to utilize the wind output and free up interface capability into the load pockets that can hold reserves. Nonetheless, the NYISO currently operates markets for operating reserves up to 30 minutes but these N-1-1-0 requirements in New York City could be satisfied by resources with longer response times. In the long term, entry of intermittent renewables is expected to lead to large deviations of net load from the forecast over multiple hours. Procuring additional reserves from resources with longer response times would allow NYISO to more cost-effectively maintain security and reliability in these situations. Hence, we recommend that NYISO evaluate the need for longer lead time reserve products. (See Recommendation #2021-1)

Long Island

OOM actions to manage 69 kV constraints fell notably since the NYISO started to incorporate the 69 kV constraints in the day-ahead and real-time markets in April, 2021. This has led to more efficient scheduling and pricing and reduced BPCG uplift in this category. However, OOM commitments for the TVR requirements on the East End of Long Island were still frequent, leading to very poor price signals in that area. We estimate significant impacts on LBMPs in the East End load pockets from these potential modeling improvements, which should provide more efficient market signals for investment that help satisfy reliability criteria. Hence, we recommend NYISO model East End TVR needs (using surrogate constraints) in the market software. (See Section VI.B and Recommendation #2021-3)

We found that the current Long Island reserve requirement was frequently inadequate to satisfy N-1-1-0 criteria and operators had to rely on OOM commitments when needed. More than 35 percent of BPCG uplift on Long Island occurred for this reason. Modeling reserve requirements in the Long Island load pockets where these OOM actions are used would improve efficiency and encourage new resources to locate where they are most valuable. Hence, we recommend that the NYISO implement reserve requirements for Long Island that are adequate to maintain reliability rather than rely on OOM actions. (See Section V.G and Recommendation #2021-2)

Transmission Planning

The NYISO has an Economic Planning Process that assesses transmission congestion over the coming years and evaluates the costs and benefits of transmission projects proposed by developers to receive cost recovery. However, since being established in 2008, no transmission has been built through this process. NYISO adopted changes to the initial study phase in 2021 to make it more flexible and informative, but the project evaluation and approval stage remains overly restrictive. We recommend several changes to this process (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.
- Voting Requirements – Economic projects are subject to an overly restrictive requirement for an 80 percent vote in favor by beneficiaries to receive funding.
- Size Threshold – Only projects exceeding $25 million are eligible for cost recovery, excluding smaller projects whose benefits exceed their costs.

Overview of Recommendations

Our analysis in this report indicates that the NYISO electricity markets performed well in 2021, although we recommend additional enhancements to improve market performance. The table below summarizes our high-priority recommendations. The majority of these recommendations were made in the 2020 SOM Report, but Recommendations #2021-1 to #2021-4 are new in this report. 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.

A complete list of recommendations and a detailed discussion of each recommendation is provided in Section XI. In total, we have nineteen outstanding recommendations that are discussed in that section. In addition, the NYISO moved forward with market reforms that addressed seven recommendations from our previous State of the Market report in 2021.

High Priority Recommendations in the 2021 SOM Report

Number	Section	Recommendation	Current Effort
Energy Market Enhancements - Pricing and Performance Incentives			
2017-1	V.G	Model local reserve requirements in New York City load pockets.	Study completed in 2021; *Dynamic Reserves* project targets market design concept proposal in 2022.
2015-16	V.A	Dynamically adjust operating reserve requirements to account for factors that change the amount of reserves that must be held on internal resources.	
2016-1	V.E	Consider rules for efficient pricing and settlement when operating reserve suppliers provide congestion relief.	
2017-2	V.A	Modify operating reserve demand curves to improve shortage pricing and ensure NYISO reliability.	
Capacity Market – Design Enhancements			
2021-4	VII.E	Improve capacity modeling and accreditation for specific types of resources.	*Improving Capacity Accreditation* Phase II process underway.
2013-1c	VII.D	Implement locational marginal pricing of capacity ("C-LMP") that minimizes the cost of satisfying planning requirements.	

I. INTRODUCTION

This report assesses the efficiency and competitiveness of New York's wholesale electricity markets in 2021.[1] The NYISO operates competitive wholesale markets to satisfy the electricity needs of New York. These markets include:

- Day-ahead and real-time markets that simultaneously optimize energy, operating reserves, and regulation;
- A capacity market that ensures the NYISO markets produce efficient long-term economic signals that guide decisions to invest in new and existing generation, transmission, and demand response resources (and/or retire uneconomic existing resources); and
- A market for transmission rights that allows participants to hedge the congestion costs associated with using the transmission network.

The energy and ancillary services markets establish prices that reflect the value of energy at each location on the network. They deliver significant benefits by coordinating the commitment and dispatch of generation to ensure that resources are started and dispatched each day to reliably meet the system's demands at the lowest cost. The coordination provided by the markets is essential 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.

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

- A market scheduling system (i.e., Coordinated Transaction Scheduling) to coordinate an economic evaluation of interchange transactions between markets.
- A mechanism that allows inflexible gas turbines and demand-response resources to set energy prices when they are needed, which is essential for ensuring that price signals are efficient during peak demand conditions.
- A real-time dispatch system (i.e., RTD) that runs every five minutes and optimizes over a one-hour period, allowing the market to anticipate the upcoming needs and move resources to efficiently satisfy the needs.

These 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,[2] 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 XI of the report provides a number of recommendations that are intended to achieve these objectives.

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

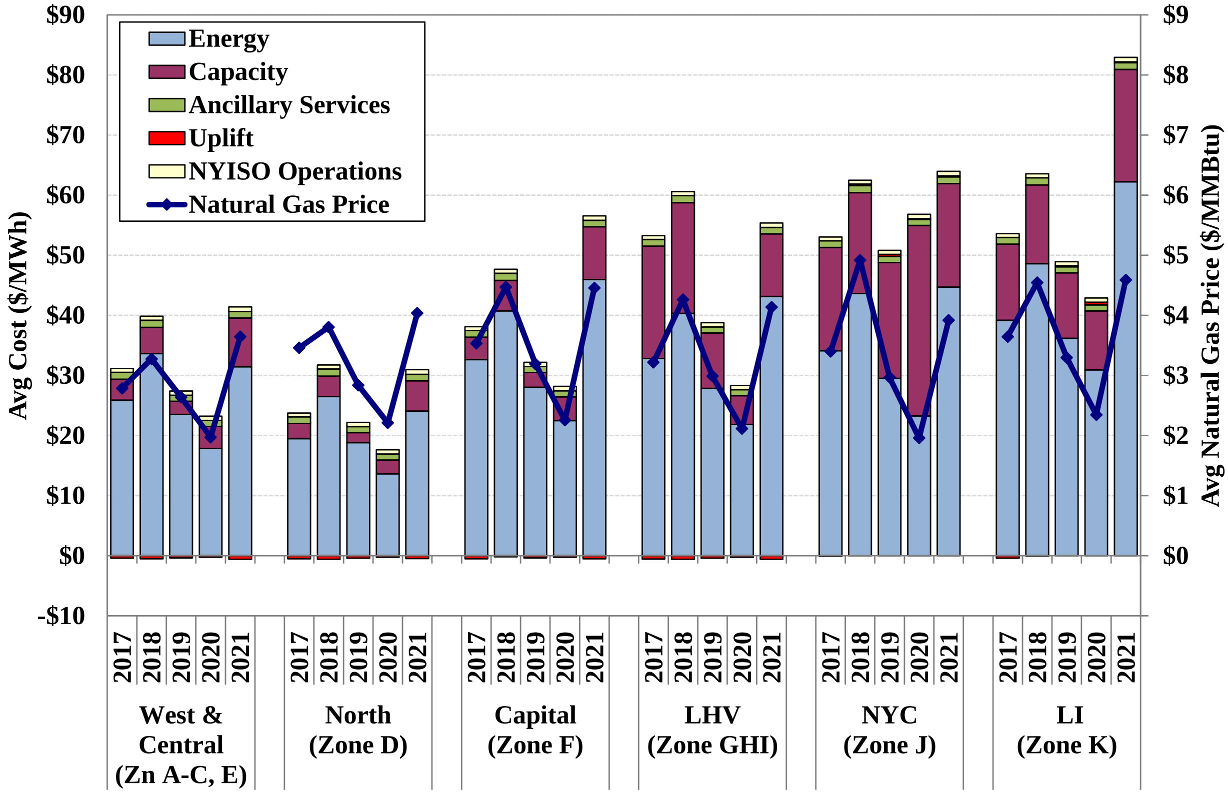
II. Overview of Market Trends and Highlights

This section discusses significant market trends and highlights in 2021. It evaluates energy and capacity costs, fuel prices, generation patterns, demand patterns, and significant market events. We also evaluate investment incentives for existing generator types in southeast New York.

A. Wholesale Market Costs

Figure 1 summarizes wholesale market costs to consumers over the past five 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.[3]

Figure 1: Average All-In Price by Region
2017-2021



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

Average all-in prices swung from very low levels in 2020 to the highest levels in seven years in 2021 in most regions.[4] All-in prices ranged from $32 per MWh in the North Zone to nearly $85 per MWh in Long Island, reflecting year-over-year increases of 73 to 100 percent for most zones. In New York City, where capacity costs usually account for a larger share of overall costs, all-in prices increased just 14 percent because of a reduction in capacity prices there. The increased all-in prices resulted mainly from the following factors:

- Natural gas prices rose from very low levels in 2020 to relatively high levels in 2021 as rising LNG exports outpaced the growth in domestic production. Consequently, the regional gas prices were the highest observed in over five years outside of peak winter conditions. Fuel prices are evaluated further in Subsection C.
- Transmission congestion increased on paths from north-to-central New York, from central-to-eastern New York, and from upstate into Long Island. These increases were driven primarily by lengthy planned policy-driven transmission outages, the Indian Point 3 retirement at the end of April, and forced outages of key transmission lines during the summer months (especially into Long Island).[5]
- Capacity price variations were mainly driven by changes in the Installed Reserve Margin ("IRM") for the system and Locational Capacity Requirements ("LCR") and the local capacity zones. These changes in requirements in addition to generator retirements led capacity prices to fall dramatically in New York City and to increase considerably in other areas. These changes are discussed further below.

Energy costs generally account for the largest single component of all-in prices, contributing between 68 and 80 percent in 2021. Higher energy costs accounted for most of the increases in all-in prices from 2020 to 2021.

Capacity costs in 2021 changed markedly from 2020 as average capacity costs:

- Increased 117 to 122 percent in Rest of State regions (i.e. Zones A-F),
- Increased 118 percent in the Lower Hudson Valley (i.e., Zones G, H, and I),
- *Decreased* 46 percent in New York City, and
- Increased 91 percent in Long Island.

As mentioned above, these changes were caused primarily by changes in the IRM and LCRs, particularly the NYC LCR, which fell by 6.3 percent from the 2020/21 Capability Year. We discuss the reasons for this in Section VII of this report. The other notable driver of changes in year-over-year capacity costs across the state include the Indian Point 3 nuclear unit retirement.

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4 The exception is Hudson Valley where all-in prices were higher in 2018.

5 Long duration transmission outages for public policy driven transmission upgrades drove significant congestion along several interfaces during 2021. Appendix Sections III.B and III.C show congestion patterns in more detail.

B. Net Revenues for 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 that 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 2 shows the net revenues and the estimated going-forward costs ("GFCs") for several existing technology types from 2019 to 2021. To evaluate the financial returns for flexibility, net revenues from day-ahead energy sales are shown separate from net revenues from balancing energy sales (and purchases) and from the sale of operating reserves. To analyze the returns for fuel-secure characteristics, net revenues are shown separately for dual-fuel and gas-only steam turbines in New York City. 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.[6] 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. The figure also shows a "Short-Term GFC" for New York City steam units, which excludes major maintenance and other capital expenditures. However, even the "Short-Term GFC" includes some plant-level costs that would be difficult to avoid by retiring a single unit.[7, 8]

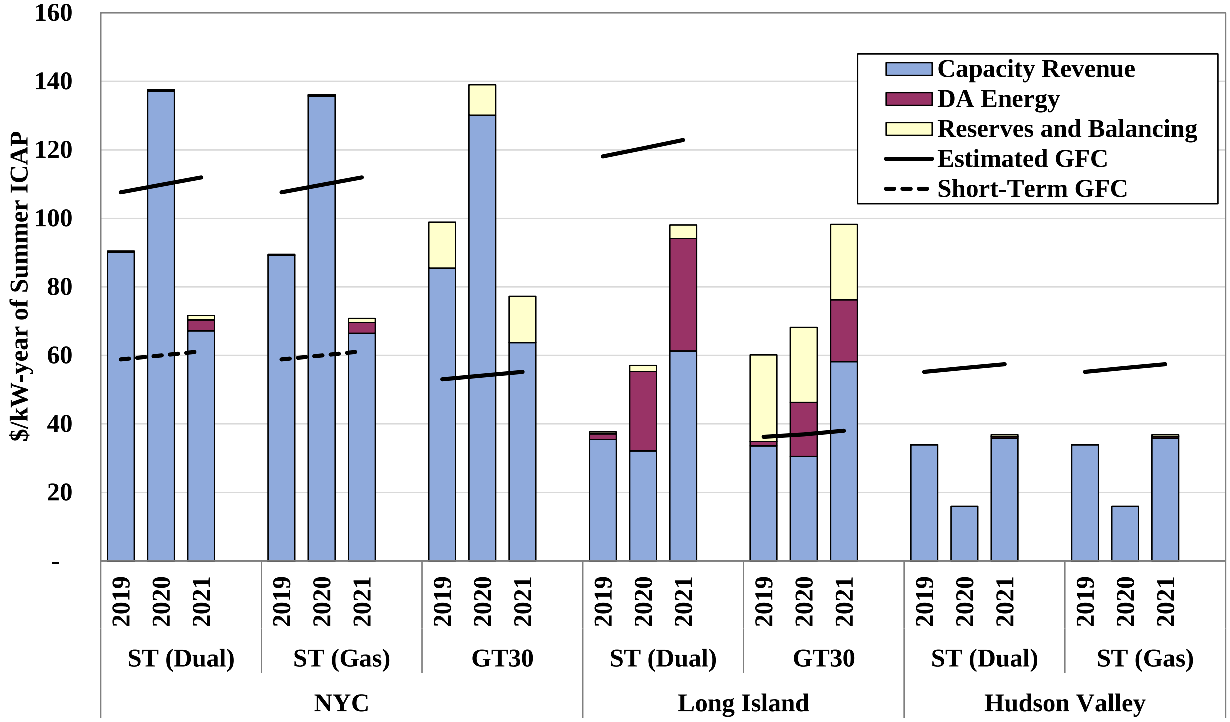
The net revenues of existing units in New York City and Hudson Valley regions increased from 2019 to 2020, and then decreased in 2021, due to fluctuations in capacity prices. Whereas, for existing units in Long Island, the net revenues increased from 2019 to 2020 and from 2020 to 2021 because of more frequent transmission outages limiting imports to Long Island. The net revenues of existing units relative to their costs varied significantly by technology and location.

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

7 The "Short-Term GFC" includes estimated fixed O&M costs, property tax and administrative costs with all major maintenance and capital expenses excluded. Additional details are provided in Appendix Section VII.

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

Figure 2: Net Revenues and Going-Forward Costs of Existing Units
2019 – 2021



Steam turbine units appear to be the most challenged economically of the technologies evaluated. 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. Due to their relatively high operating costs and physical constraints that require long start-up lead times and run times, steam units tend to earn little from the energy and reserve markets, except in Long Island. Net revenues for a steam turbine in New York City were above an estimated "Short-Term GFC", which assumes that its owner defers major maintenance and other expenses, although a resource owner that defers maintenance will face increased operating risks. Our analysis finds that dual-fuel steam turbines would earned little more than gas-only units in New York City and the Hudson Valley from 2019 to 2021, although this may change as additional dual-fuel generators and other fuel-secure units retire in the next few years.[9]

In Long Island, steam turbine generators are compensated through a long-term contract that does not expire until 2023, so these units are less-exposed to wholesale prices and may have stronger incentives to perform maintenance. In Hudson Valley, steam turbine generators may have incentives to defer maintenance.

9 From 2019 to 2021, we estimate that there were interruptions of service on just five days that would have required gas-only steam units in New York City to take forced outages or derates.

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, the value of its interconnection rights and CRIS rights, and the owner's expectations of future market prices.

Gas turbine units in New York City and Long Island were estimated to receive net revenues consistently above the estimated GFC because of high reserve market revenues and relatively low GFCs for these units. These smaller, more flexible units derive considerable value from reserve markets despite relatively low prices in recent years with 10-minute units deriving as much as 25 percent of their net revenues from reserves and balancing operations in New York City and Long Island in 2021. Less flexible steam units, on the other hand, gain almost no value from reserve markets. As the grid prepares for a future where flexible and responsive generation will be pivotal to support policy goals and reliability, reserve prices will be an important revenue source for flexible technologies and many of our recommendations focus on improvements in this area.

Despite the strong net revenues for gas turbines relative to their GFCs, many of these units have indicated their intent to retire given the significant additional capital costs required 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.[10]

Existing fossil fuel generators face considerable economic and regulatory pressure that are leading some to retire. A key role of the wholesale market is to provide incentives that lead the least valuable units to retire while retaining generators with needed characteristics. The wholesale market should efficiently reward reliability, flexibility, and fuel-security if the New York power system is going to become clearner as envisioned by policy-makers while maintaining reliability at lowest possible cost. Hence, we have recommended market enhancements that would help reward resources more appropriately for these characteristics to help steer investment in favor of resources that provide the greatest value.[11]

C. Fuel Prices

In recent years, fossil fuel price fluctuations have been the primary driver of changes in wholesale energy prices. Figure 3 displays monthly natural gas prices from 2018 to 2021 for

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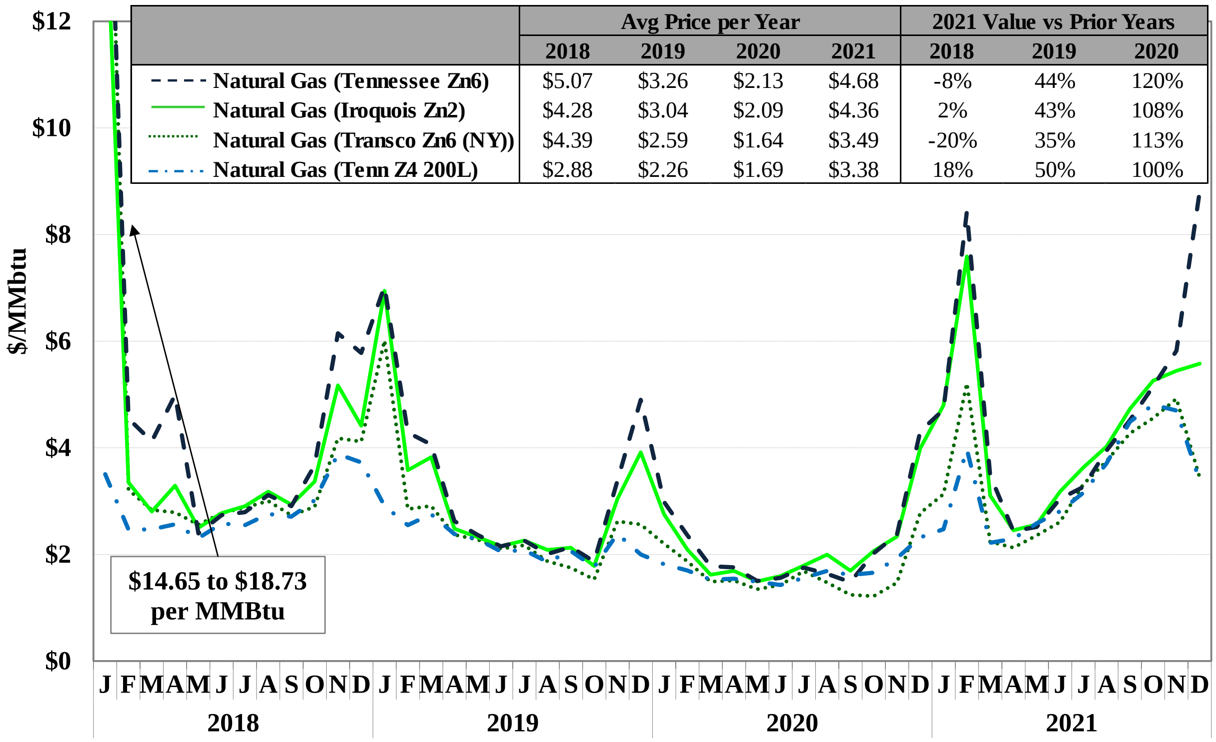
10 See DEC's proposed rule *Ozone Season Oxides of NOx Emission Limits for Simple Cycle and Regenerative Combustion Turbines*. See link.

11 Our recommendations are listed in Section XI. Appendix Section VII.D provides an analysis estimating the effects on net revenues for various technologies from selected recommendations.

several relevant indexes to the system. The inset table shows the average annual gas prices for those indexes as well as how the 2021 annual value compares to each of the preceding 3 years (i.e., 2018-2020).[12]

Figure 3: Average Fuel Prices and Real-Time Energy Prices
2018-2021



	Avg Price per Year				2021 Value vs Prior Years		
	2018	2019	2020	2021	2018	2019	2020
Natural Gas (Tennessee Zn6)	$5.07	$3.26	$2.13	$4.68	-8%	44%	120%
Natural Gas (Iroquois Zn2)	$4.28	$3.04	$2.09	$4.36	2%	43%	108%
Natural Gas (Transco Zn6 (NY))	$4.39	$2.59	$1.64	$3.49	-20%	35%	113%
Natural Gas (Tenn Z4 200L)	$2.88	$2.26	$1.69	$3.38	18%	50%	100%

Average natural gas prices across the state rose substantially in 2021 from particularly low levels in 2020. Year-over-year, gas prices increased 100 to 120 percent for major pipeline indices. Part of the reason for this dramatic rise was due to the historically low gas prices in 2020 during the Covid-19 pandemic. However, gas prices in 2021 were higher for much of the year (June to November) going back at least five years. Only 2018 exhibited higher annual average gas prices in some areas as a consequence of the extraordinary winter weather in January 2018.

D. Demand Levels

Demand is another key driver of wholesale market outcomes. Higher demand levels drive high cost peaking resources to set prices as the marginal resource more frequently. Additionally, transmission congestion into load centers generally increases as demand levels rise. Lastly, annual peak demand forecasts are used to determine the MW-requirements in the capacity market.

12 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.

Table 1 shows the following load statistics for the New York Control Area ("NYCA") since 2012: (a) annual summer peak; (b) reconstituted annual summer peak; (c) annual winter peak; and (d) annual average load. The reconstituted summer peak incorporates any demand response that was activated during the peak load hour, either by utility deployment or by the NYISO. Therefore, a reconstituted peak load gives a truer sense of the supply resource requirements.

Table 1: Peak and Average Load Levels for NYCA
2012 – 2021

Year	Load (GW)			
	Summer Peak (as Reported)	Summer Peak (Reconstituted)	Winter Peak	Annual Average
2012	32.4	32.6	23.9	18.5
2013	34.0	34.8	24.7	18.7
2014	29.8	29.8	25.7	18.3
2015	31.1	31.1	24.6	18.4
2016	32.1	32.5	24.2	18.3
2017	29.7	29.7	24.3	17.9
2018	31.9	32.5	25.1	18.4
2019	30.4	30.4	24.7	17.8
2020	30.7	31.2	22.5	17.1
2021	30.9	31.3	22.5	17.3

The average load across the system recovered slightly in 2021. Despite the recovery, average load levels in 2021 remained historically low averaging just 17.3 GW over the year. This continued a general downward trend in load that has been observed since 2013. Peak load has exhibited a similar overall pattern where it has increased slightly from 2020 but has fallen substantially over the past decade.

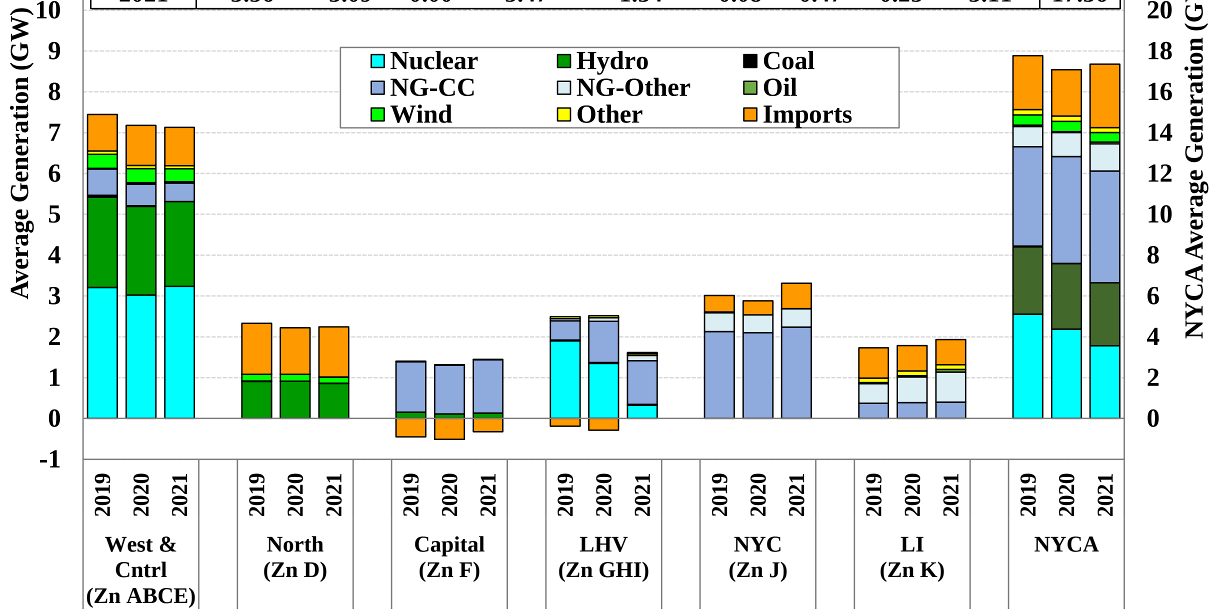
E. Generation by Fuel Type

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. Figure 4 displays the annual generation by resource type from 2019 to 2021 (including net imports). Net import levels are assigned to areas as follows: (a) Ontario imports in the West & Central Zones; (b) Quebec imports in the North Zone; (c) imports over the primary PJM interface are split 7 percent to NYC, 47 percent to the Lower Hudson Valley, and 46 percent to the West & Central Zones; (d) net imports over the primary ISO-NE interface in the Capital Zone; and (e) the Schedule Lines to their applicable regions (i.e., Cross Sound Cable, Neptune Cable, and 1385 Line in Long Island and the HTP and Linden VFT Lines in NYC). Since there were net exports to ISO-NE, they are shown as negative values.

Gas-fired resources accounted for the largest share of internal generation in each year of 2019 to 2021, and this share has risen from 41 percent in 2019 to 48 percent in 2021. This increase is due in part to the recent construction of new combined cycle facilities in the Hudson Valley and the retirement of the Indian Point nuclear generators in the same region.

Figure 4: Generation by Type and Net Imports to New York
2019-2021

Year	Internal Generation by Fuel Type in NYCA (GW)									
	Nuclear	Hydro	Coal	NG-CC	NG-Other	Oil	Wind	Other	Imports	Total
2019	5.11	3.29	0.05	4.86	1.00	0.06	0.51	0.25	2.64	17.77
2020	4.37	3.21	0.02	5.23	1.18	0.04	0.51	0.26	2.28	17.09
2021	3.56	3.09	0.00	5.47	1.34	0.08	0.47	0.25	3.11	17.36



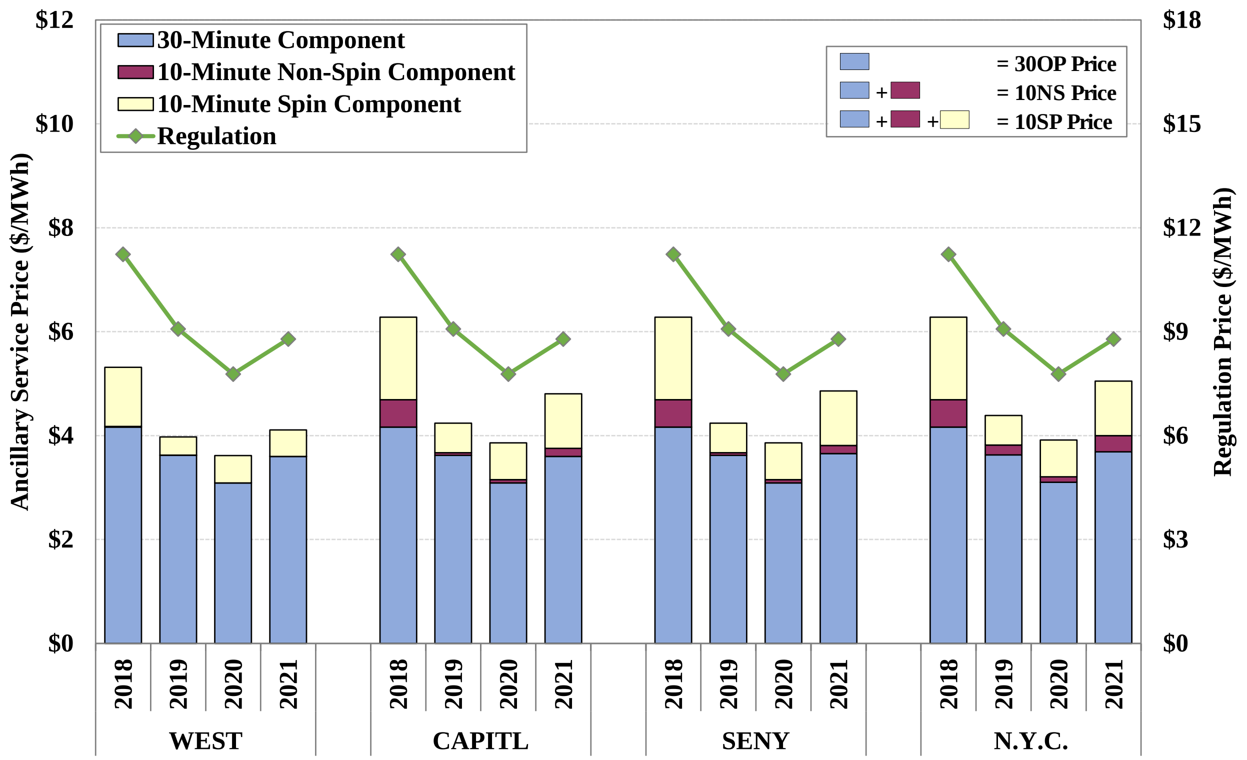
Before 2021, over half of internal generation in New York came from a combination of hydro and nuclear units. With the retirement of Indian Point 2 in 2020 and Indian Point 3 in 2021, the share of internal generation from nuclear and hydro resources combined fell to 47 percent in 2021. Over this period, the imports have risen, especially from PJM to Lower Hudson Valley and New York City, while exports to New England from the Capital Zone and the Lower Hudson Valley have fallen. Interchange is discussed further in Section VIII.A.

Despite a relatively mild winter, oil-fired generation doubled in 2021 from prior year levels. This was driven primarily by increased output from oil-fired units in Long Island during the summer. While Long Island typically relies on a small amount of oil-fired generation in high summer load conditions, utilization of these resources increased in 2021 due to the coincident outages of the Y49 and Y50 lines from early-August until late-September, which nearly "islanded" the zone, making it even more reliant on high cost internal generation to meet load.

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. Despite their small contribution to the overall system costs, the ancillary services markets provide additional revenues that reward resources that have high rates of availability, especially peaking units. Figure 5 shows the average prices of the four ancillary services products by location in the day-ahead market in each of the past four years.[13]

Figure 5: Average Day-Ahead Ancillary Services Prices
2018-2021



Average day-ahead prices for all reserve products rose in 2021, consistent with the increase in opportunity costs of not providing energy when energy prices are higher. Day-ahead offers for reserves also rose, though not by the same magnitude as energy offers.[14]

The price of the NYCA 30-minute reserves has accounted for most of the overall day-ahead market reserve procurement costs in recent years, while the 10-minute spinning reserves component accounted for a considerable portion as well. Although day-ahead LBMPs rose by as much as 103 percent from the previous year in some zones, the rise in reserve prices was far

13 See Appendix Section I.I for additional information regarding the ancillary services markets and detailed description of this chart. Details in that chart are monthly but display the same information.

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

smaller.[15] Day-ahead 30-minute reserve prices rose by 16 to 19 percent, while the 10-minute products rose by up to 29 percent.

G. Long Island Transmission Outages in the Summer of 2021

Some years bring particularly challenging conditions during peak winter and summer demand periods. In 2021, Long Island experienced high summer load conditions paired with extended severe transmission outages when both 345 kV circuits (the Y49 and Y50 lines) from upstate New York to Long Island were forced out for nearly seven weeks.[16] The combined outage reduced transfer capability to Long Island by approximately 20 percent of its peak summer load during some of the hottest weather of the summer.

Our analysis of this period produced several key findings:

- *Inefficient Reserve Pricing* – Long Island reserve prices do not reflect the cost of satisfying Long Island reserve requirements or reserve shortages. Severe reserve deficiencies occurred and were not reflected in reserve prices, including:
  - Four days when available reserves fell below the size of the largest contingency,
  - Eight days when it fell below the two largest contingencies, and
  - Six days when emergency demand response was activated.

  Recommendation 2019-1 is for the NYISO to incorporate Long Island reserve constraints into the reserve clearing prices for Long Island.
- *Inadequate Reserve Requirements* – The reserve requirement of 540 MW on Long Island was insufficient, so the operators committed generation out-of-market to maintain adequate reserves on 31 days this summer, contributing to poor price formation and incentives for suppliers. Recommendation 2021-2 would increase the reserve market requirement to be consistent with N-1-1-0 criteria (i.e., to be able to return flows below normal ratings after the largest two contingencies).
- *Inflated Capacity Accreditation* – Significant amounts of generating capacity on Long Island was never utilized, even during the most severe operating reserve deficiencies. Approximately 420 MW of "emergency" capacity (i.e., capacity offered above a resource's normal UOL) was never made available to the market and never dispatched out-of-market. Although this capacity can be dispatched by the operator using emergency operations procedures, some may require significant lead time and operators may be reluctant to activate emergency capacity if it increases the likelihood of a generator trip. Recommendation 2021-4 would eliminate or appropriately discount the capacity accreditation for such capacity to be consistent with its resource adequacy value.

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15 See Section I.H of the Appendix for details on energy price changes year-over-year.

16 The Y50 line was out of service from July 17 to September 20, and the Y49 was out of service from August 6 to October 15.

Furthermore, we observed a pattern of extremely inflexible offers by many gas-fired generators that had significant market effects during this period. Specifically, self-scheduling to high output levels caused internal bottlenecks and export constraints, resulting in very low prices in some morning hours, particularly the last few hours of the gas day (i.e., from 7:00 am to 10:00 am).

The following figures illustrate this pattern in detail by showing scheduled energy from:

- Real-time imports over the DC cables connecting Long Island to PJM and ISO-NE;
- Real-time production by Long Island generators categorized as:
  - Minimum generation levels,
  - Self-schedules levels, i.e., energy produced above minimum generation level and offered inflexibly, and
  - Flexible energy offers, i.e., energy produced above minimum generation and self-commitment levels and therefore capable for ramping in the downwards direction.
- Day-ahead scheduled energy from Long Island generators and the DC cables.

The figures also show the zonal integrated real-time hourly energy price.

Figure 6 shows this detail for August 11, while Figure 7 shows these levels as the average values across the entire period that both 345-kV lines were out of service.

Figure 6: Long Island Market Outcomes on August 11, 2021

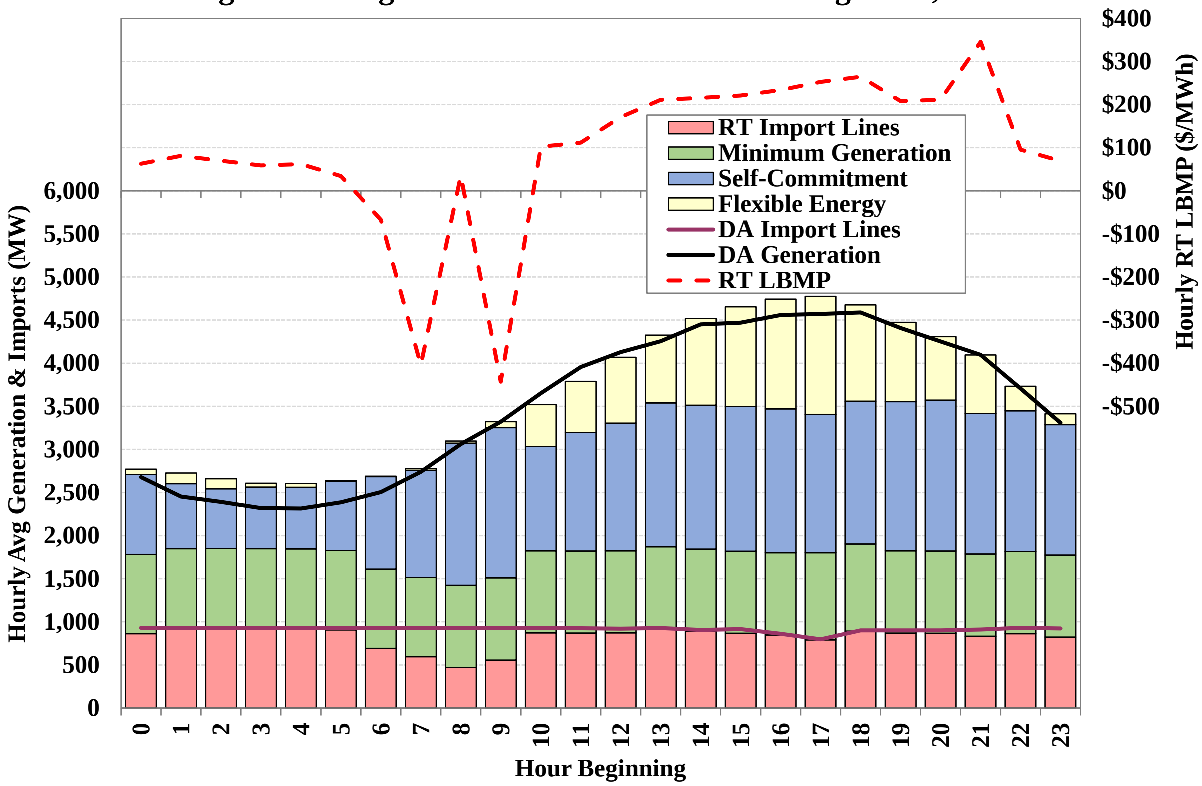
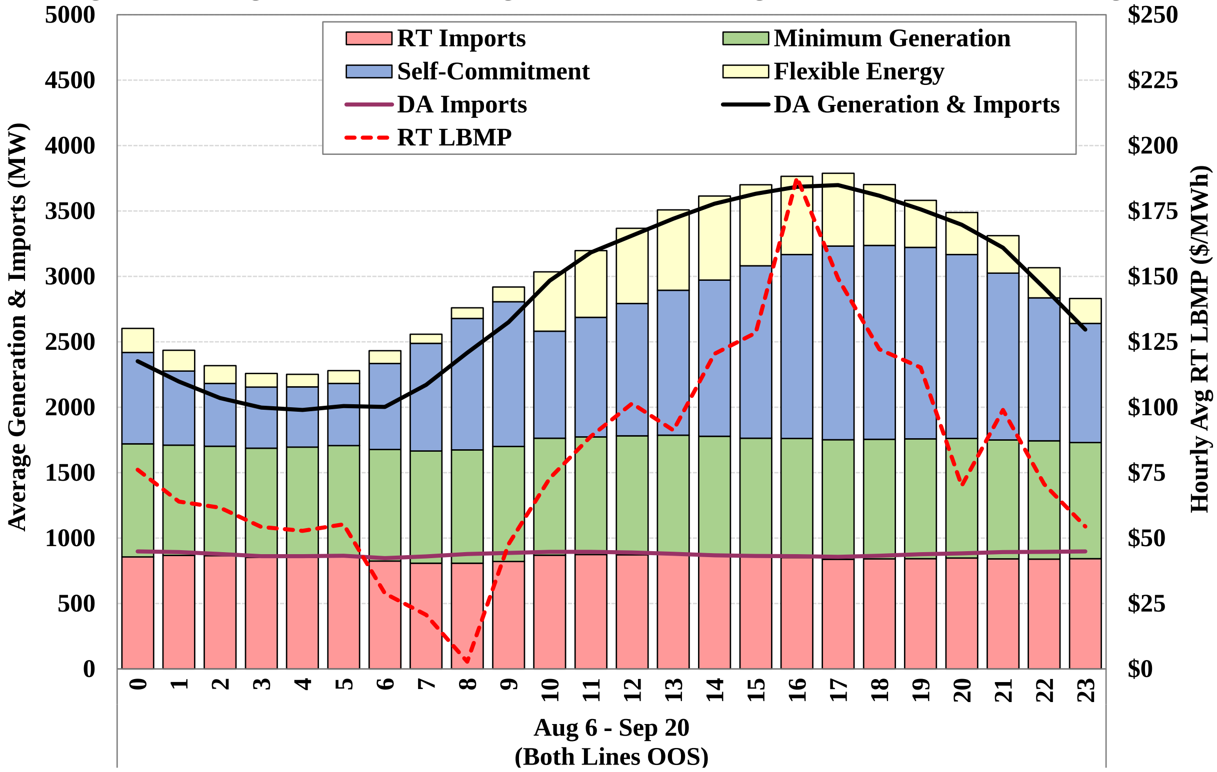


Figure 7: Long Island Scheduling and Prices during Joint Y49 and Y50 Outages



The intraday price variability observed on Long Island during this spell is apparent from the average zonal real-time price in HB 16 of nearly $190/MWh compared to HB 8 of less than $3/MWh. In fact, average prices fell sharply in hours 6 through 8 just as load conditions started to rise each day. This occurred because many gas-fired generators with day-ahead energy schedules submitted self-schedules above their day-ahead scheduled level, leading to export congestion and very low and sometimes negative energy prices. While this sort of inflexible real-time scheduling is sometimes necessitated by gas operating restrictions, we found that the amount of self-scheduling generally exceeded what was necessary for gas-fired generators to satisfy their obligations (to the gas operator) efficiently.

Uneconomic over-production leads to obvious market inefficiencies such as negative energy prices. This can increase costs to consumers when it: (a) provides suppliers an opportunity to purchase energy at negative prices that was initially sold in the day-ahead market, (b) leads to balancing congestion residual uplift, and (c) bid production cost guarantee uplift. The NYISO has advanced two tariff changes that should reduce the costs to consumers from such offer behavior. First, the NYISO recently revised its market power mitigation measures to deter suppliers that could benefit from uneconomic overproduction.[17]

[17] See FERC Order on the filing which approved tariff changes effective February 21, 2022.

Second, the NYISO has proposed to modify the real-time BPCG rules to avoid making BPCG payments to generators that cause very low prices by self-scheduling. This is because NYISO operators often had to issue out-of-merit ("OOM") requests to reduce output from self-scheduled units to relieve transmission constraints. Currently, such generators receive BPCG for responding to these OOM requests. Generators on Long Island collected over $1 million in RT BPCG during such conditions in 2021. The NYISO proposal would amend the tariff to remove BPCG eligibility to generators in this type of situation.[18]

[18] See NYISO presentation titled "RT BPCG for Generators Self-Scheduled Above DAM Schedule and OOM for Reliability" presented by Mark Buffaline on March 3, 2022.

III. LONG-TERM INVESTMENT SIGNALS AND POLICY IMPLEMENTATION

A well-functioning wholesale market establishes transparent and efficient price signals to guide generation and transmission investment and retirement decisions. The vast majority of proposed new projects are now driven by New York State clean energy policies and earn a combination of NYISO market revenues, state subsidies, and federal tax incentives. Efficient wholesale markets play a pivotal role in driving investors in clean energy resources to seek the most valuable projects, technologies, and locations. These incentives help avoid wasteful spending and steer invesment toward projects that will satisfy state goals at a lower cost to ratepayers. Well-designed markets also encourage investments that complement clean energy projects, such as resources that are needed for grid reliability and flexibility. This section:

- Evaluates investment signals under recent conditions by comparing the net revenue that generators would have received from the NYISO markets and government incentives to their capital investment costs,[19] and
- Analyzes whether NYISO's markets are designed to provide efficient incentives to invest in resources that support state policy, with a particular focus on energy storage.

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 rewards 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 state solicitations 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.[20]
- *Developers of new flexible resources* – Increased flexibility will be needed to integrate high levels of renewable generation, particularly around critical transmission bottlenecks. 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.

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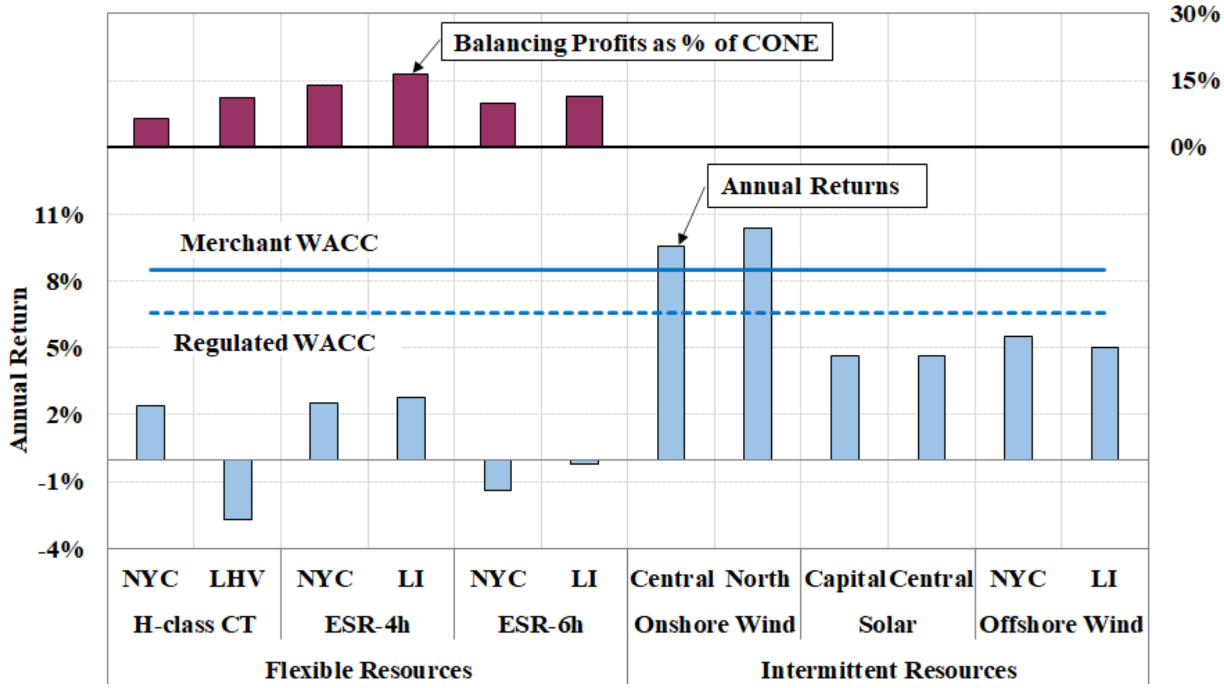
19 Net revenue is the total revenue that a generator would earn less its variable production costs. Investors seek to earn sufficient net revenue to recover the cost of their capital investments in generating units.

20 See our review of NYISO's 2019 CARIS Phase 1 study (available here) and Sections IX.A and IX.B of our 2020 NYISO State of the Market report (available here) for a discussion of the risks faced by developers that enter into Index REC contracts.

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 8] shows the estimated after-tax annual return on investment in several types of new flexible and intermittent resources. Annual returns are based on historical price data from 2019 to 2021 (using costs for entry in 2021), including energy and ancillary services revenues, capacity market revenues, and applicable incentives including renewable energy credits, ITC/PTC, and bulk storage incentives.[21] The figures compare the annual return for each project with the after-tax WACC for: (a) a merchant entrant, and (b) a regulated entity.[22] A project with an estimated annual return above its weighted average cost of capital would be profitable. The bars in the top panel show the share of E&AS net revenues that flexible resources would earn from balancing profits (flexible participation in reserve and real-time energy markets).

Figure 8: After-Tax Annual Return of New Generation
2019 – 2021



The economics of generation investment varies significantly by technology and zone. For example, land-based wind appears to be more cost-effective under current conditions than solar,

21 Details on estimated net revenues can be found in Appendix Sections VII.A and VII.C.

22 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 recent rate cases for Consolidated Edison, Orange & Rockland, New York State Electric & Gas Corporation, and Rochester Gas and Electric Co.

based on the revenues that each would receive and four-hour storage appears to be more cost-effective than six-hour storage. Differences in market revenue indicate which clean energy projects are most valuable to the system in terms of deliverability, reliability, and congestion relief. The most economic projects are likely to submit the lowest-cost proposals in state solicitations, reducing the cost of satisfying policy targets.

Our analysis also illustrates the importance of balancing and reserve market revenues for flexible resources. As shown in the figure, both ESRs and new CTs would have earned substantial revenues from the balancing and reserve markets (up to 17 percent of their CONE for ESRs and up to 11 percent for new CTs). In this report we make several recommendations to enhance the efficiency of pricing and performance incentives in the real time markets, which would increase the revenues of flexible resources.[23] Furthermore, high levels of renewable penetration are expected to reduce average energy prices while increasing their variability and the need for ancillary services. Hence, the recommended enhancements are likely to have larger effects on investment incentives for flexible resources after additional renewables are added to the grid.[24]

Discussion of Incentives for New Units by Technology Type

Based on 2019 to 2021 outcomes, the only technology that appears to be economic is onshore wind, which also receives substantial returns from state and federal incentives. Investments in all other technologies and locations would earn well below even the regulated WACC. However, there will likely 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.

Gas-fired Combustion Turbines – The estimated annual return is well below the typical merchant WACC for the locations that we analyzed because of the large capacity surpluses in New York City and the Lower Hudson Valley.[25] 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, it may be infeasible to build or repower a gas-fired unit given

23 Subsection VII.D estimates how Recommendations #2015-16, #2016-1, #2017-1, and #2017-2 would affect the net revenues for several flexible technologies. However, Recommendations #2019-1, #2020-2, #2021-2, #2021-3 would likely also have substantial effects on the net revenues for flexible technologies.

24 A recent study of long-term market dynamics in the neighboring ISO-NE system, in which several states have ambitious clean energy goals, finds that while high levels of renewable deployment reduce average LBMPs, they also significantly increase the variability of LBMPs, in part due to increasing frequency of negative prices. These dynamics would tend to increase the profitability of flexible resources like storage. See Analysis Group, "Pathways Study – Evaluation of Pathways to a Future Grid", February 2022 draft, available here.

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

recent permitting decisions[26] and an executive order prohibiting new gas infrastructure in New York City.[27]

Renewable generators – At recent historical prices and costs, estimated annual returns (including REC payments) 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.[28] Renewable projects are reportedly facing upward cost pressure due to tariffs and supply chain shortages, although projected long-term declining technology costs could lead them to be profitable at many locations in the future. In New York, state and federal incentives account for the majority of net revenues (as high as 61 percent) for all renewable projects evaluated.[29] 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 and six-hour battery storage projects from 2019 to 2021 was substantially lower than the regulated WACC even after inclusion of state incentives. However, the economics of battery storage are expected to improve in the coming years due to declining costs, opportunities to add energy storage on the site of existing generators (i.e., hybrid storage), price volatility caused by renewable generation, and from recommended market design enhancements to the energy and ancillary services markets. Hence, it is likely that merchant storage investment could be economic on an unsubsidized basis in the coming years, as discussed in the following subsection.[30]

B. Market Incentives for Investment in Policy-Supported Resources

New York's Climate Leadership and Community Protection Act (CLCPA) targets transformational changes in the state's resource mix towards clean energy and away from polluting sources. The CLCPA 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. However, energy and capacity markets still provide

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26 See permit denial letters from New York Department of Environmental Conservation for Astoria Replacement and Danskammer Generating Station projects available at link, and link, respectively.

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

28 So far development in land-based wind has outpaced development in solar PV in New York. However, future renewable projects selected in recent state solicitations have been primarily solar. Wind projects have reportedly encountered siting and permitting difficulties, while solar projects are expected to have more favorable future cost decreases and treatment under federal tax incentive programs.

29 State and federal incentives make up 48 percent of estimated revenues for solar PV, 56 to 61 percent for land-based wind, and 44 to 57 percent for offshore wind in 2021. See subsection VII.C of the Appendix.

30 While the annual return in 2019-2021 for six-hour battery is significantly lower than four-hour battery, this gap may reduce in future years as rising battery penetration causes the marginal capacity value of shorter-duration storage to fall relative to longer-duration storage.

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.

We have previously discussed the role that NYISO markets play in coordinating investment in renewable resources.[31] The CLCPA also requires 3 GW of energy storage by 2030, and it is likely that over the long term larger amounts will be needed to integrate renewables efficiently. Although Figure 8 shows that market revenues in recent years have been too low to motivate storage investment, this is likely to change in the future as penetration of renewable generating capacity – and hence, the need for storage to help integrate it – increases.

Energy storage is capable of providing wholesale services that support the clean energy transition in the following ways:

- Charge to absorb excess renewable generation that would otherwise be curtailed, allowing more load to be served by renewable sources, or more generally, charge when lower-emitting resources set marginal prices and discharge when higher-emitting and more expensive resources are marginal;
- Provide capacity to satisfy NYISO resource adequacy requirements, reducing the amount of conventional capacity needed for reliability; and
- Provide ancillary services that improve the system's flexibility to accommodate resources whose output is variable and uncertain.

In this subsection, we examine whether NYISO market prices for each of the services listed above provide efficient incentives to invest in storage when it cost-effectively supports clean energy targets. Where market prices do not accurately reflect the value of storage (including environmental benefits), we highlight recommended market design improvements.

Market Signals for Storage – Renewable Energy Integration

Storage is appropriately compensated for reducing curtailment if LBMPs reflect the environmental value of renewable generation. This is the case if: (a) generator offers include carbon pricing as an input cost, or (b) renewable supplier offers reflect REC payments as a negative input cost. In New York, contracts for RECs are currently the primary mechanism for supporting renewable investment. Renewables receiving RECs accept prices in the energy market as low as the negative value of their REC payments. This causes LBMPs to be negative when excess renewable generation must be curtailed. Negative prices signal that there is value in charging a storage unit in order to avoid wasting the environmental value associated with a curtailed REC. Hence, negative prices serve a valuable purpose because they accurately indicate when additional storage would support clean energy goals.

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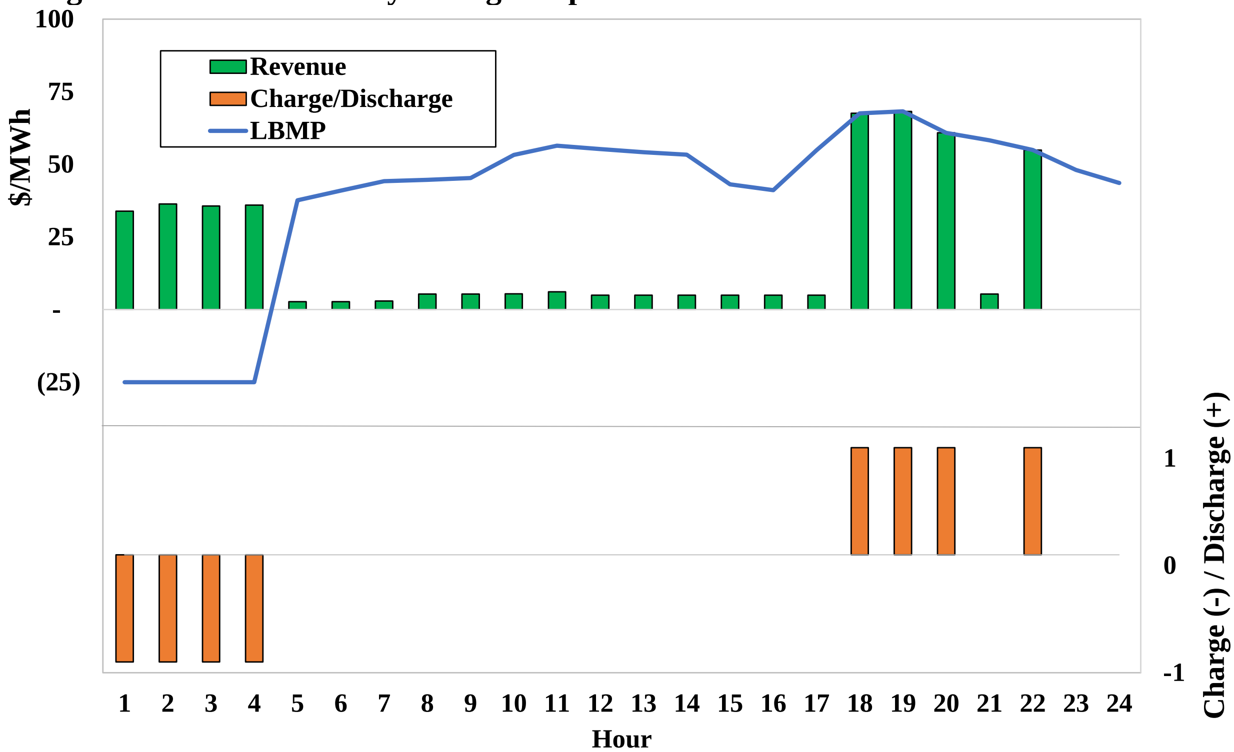
31 See our review of NYISO's 2019 CARIS Phase 1 study (available here) and Sections IX.A and IX.B of our 2020 NYISO State of the Market report (available here)

The figures below illustrate how the market encourages storage investment in response to curtailment. We modeled optimal dispatch of 4-hour storage in the energy and reserve market using day-ahead LBMPs derived from the NYISO's draft System and Resource Outlook (SRO) study for the year 2028.[32] This is done for a 'Base Case' with minimal renewable additions and a 'Contract Case' including 9.5 GW of future renewable projects that have been awarded state contracts, including over 4 GW of offshore wind in New York City and Long Island (Zone K). [33]

Figure 9 shows projected hourly LBMPs, charging and discharging of a hypothetical storage unit, and revenues to the storage unit for a single illustrative day in the Contract Case at a Zone K offshore wind node. Figure 10 summarizes annual energy and ancillary services net revenues for the hypothetical storage unit for the Base Case using Zone K prices and for the Contract Case using prices at a Zone K node where there is curtailment of offshore wind generation.

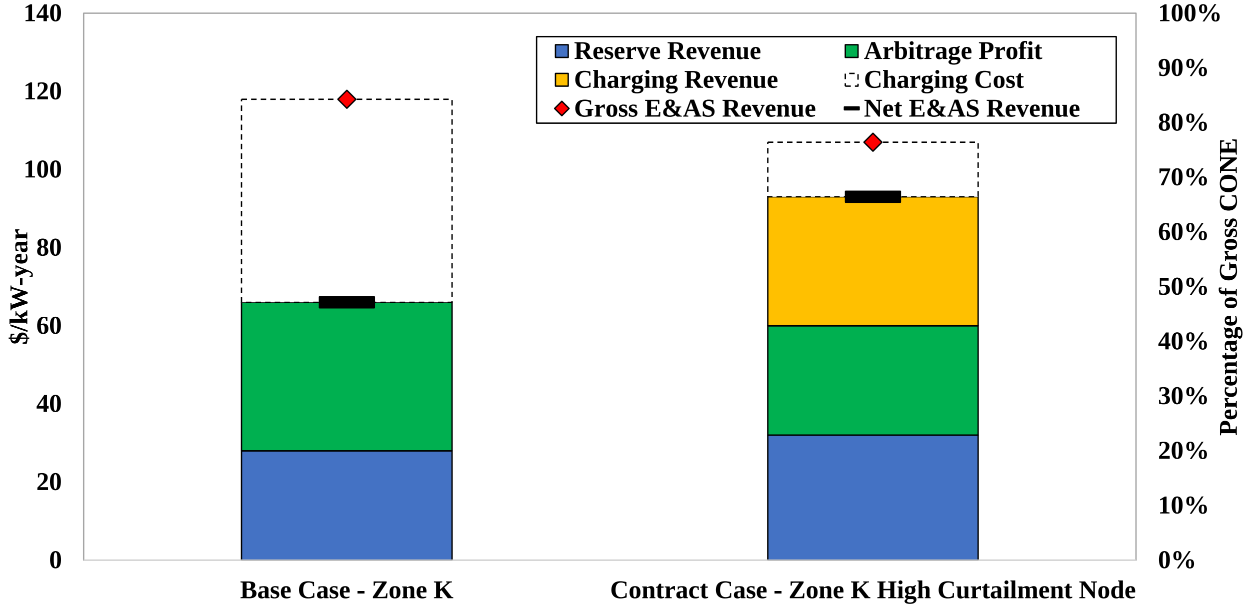
Figure 9: Illustrative Daily Storage Dispatch and Revenues at Node with Curtailment



32 The SRO includes production cost modeling of future NYISO system conditions under multiple scenarios. At the time of writing, results of the SRO are in draft form. We developed day-ahead LBMPs using hourly prices from the SRO and historical benchmark data. For details of this approach, see the Technical Appendix of our comments on NYISO's 2019 CARIS Phase I study, available here.

33 While the Contract Case is hypothetical, the inclusion of 4 GW makes it representative of conditions before the Zone K Export Public Policy Transmission Project is built given that project is designed to help integrate 9 GW of offshore wind in New York City and Long Island.

Figure 10: Impact of Curtailment on Storage Net E&AS Revenues



This analysis illustrates how the value of storage is reflected in market revenues. In Figure 9, negative prices occur in hours 1-4 due to curtailment of offshore wind. Instead of having to purchase energy, the hypothetical storage unit is paid to charge during these hours because it adds demand when LBMPs are negative. The storage unit is paid to charge at a rate of $25 per MWh, which is the equal to the REC price that offshore wind generators are assumed to receive. Hence, when storage marginally reduces curtailment of renewable generation, it is compensated equivalent to an additional unit of renewable generation. Negative prices thus allow storage to internalize the environmental value of integrating renewables (represented by the REC price) even if the storage unit receives no compensation other than from the NYISO market.

Figure 10 shows that revenues from reducing renewable curtailment are potentially large when significant curtailment would occur. Compared to the Base Case for Zone K, net revenues to the hypothetical storage unit are $25 per kW-year (38 percent) higher at the high curtailment node, driven largely by revenues from charging when LBMPs are negative. Net E&AS revenues in the contract case are equal to 64 percent of the levelized gross cost of new entry (CONE) of storage in Zone K, likely making storage investment economic in this case when combined with capacity revenues.[34] This suggests that if incoming renewable projects are expected to be curtailed,

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34 For example, at prevailing 2021 Long Island capacity prices of $65/kW-year, the hypothetical storage unit in the contract case would earn total revenues (after adjusting for marginal capacity value) of $145/kW-year, exceeding the projcted gross CONE of $140/kW-year. By contrast, in the Base Case the same project would earn $112/kW-year, falling short of the gross CONE.

NYISO markets will provide strong signals to invest in storage at nearby locations which will mitigate the curtailment.[35]

The result discussed above is efficient because storage is compensated for integrating renewables if and only if it marginally increases the amount of renewable energy that can serve load instead of being curtailed. If all renewable generation in an area can already be injected (such as if a transmission solution eliminates all curtailment), revenues to storage will be smaller because storage would not marginally increase the amount of renewable generation that can be utilized. Hence, NYISO prices signal the efficient quantity and location of storage investment for reducing curtailment.[36] If storage investment exceeds efficient levels (such as if mandatory contracting outpaces curtailment-driven needs), it may provide little incremental environmental value while requiring high contract payments due to low market revenues.

Market Signals for Storage – Capacity Value

NYISO recently made tariff changes that will accredit all capacity suppliers based on their marginal impact on reliability.[37] The marginal capacity value of storage is similar to its ability to replace capacity otherwise provided by conventional fossil units, which typically have higher UCAP values. When storage has a higher marginal capacity value, it can replace a larger quantity of existing generation while maintaining the same level of reliability. Under NYISO's proposal, this value is reflected in higher capacity payments to storage.

Figure 11 shows simulated marginal capacity value of 4-hour storage in New York City as systemwide storage deployment increases. Marginal value curves are shown for four future years. Each year assumes a different level of intermittent renewable penetration and load conditions based on preliminary capacity expansion results from NYISO's ongoing SRO study.[38]

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35 This example shows curtailment of offshore wind in Zone K, although this will be reduced by the Public Policy Transmission solicitation currently underway. This example is not intended as a *specific* forecast of where storage investment will be valuable, but it illustrates that storage revenues will be elevated at *any* location where renewable curtailment occurs. Given the large amount of renewable generation required by the CLCPA, it will not be cost effective to eliminate all systemwide curtailment using transmission solutions.

36 Note that it is efficient for some curtailment to occur even when renewable goals are fully satisfied, which would preserve price signals that lead to storage profits. This is similar to the well known finding that efficient transmission planning need not completely eliminate congestion, because the cost of adding new transmission capacity eventually outweighs the diminishing congestion relief benefit.

37 See FERC Docket ER22-772, Section VII.E, and Appendix Section VI.I.

38 At the time of writing, results of the SRO capacity expansion analysis are preliminary. See March 24, 2022 presentation to NYISO ESPWG, available here. We used the preliminary "Low UPV Capital Cost" scenario (slide 46), which includes a significant share of solar among new utility-scale renewables consistent with observed patterns from recent NYSERDA solicitations. We developed capacity credit values by inputting the generation mix and hourly load form the draft SRO to our capacity value simulation for each run year.

We developed these values using a simplified deterministic model that simulates key features of marginal capacity accreditation.[39]

Figure 11: Storage Capacity Value by Quantity and Renewable Penetration Level

New York City

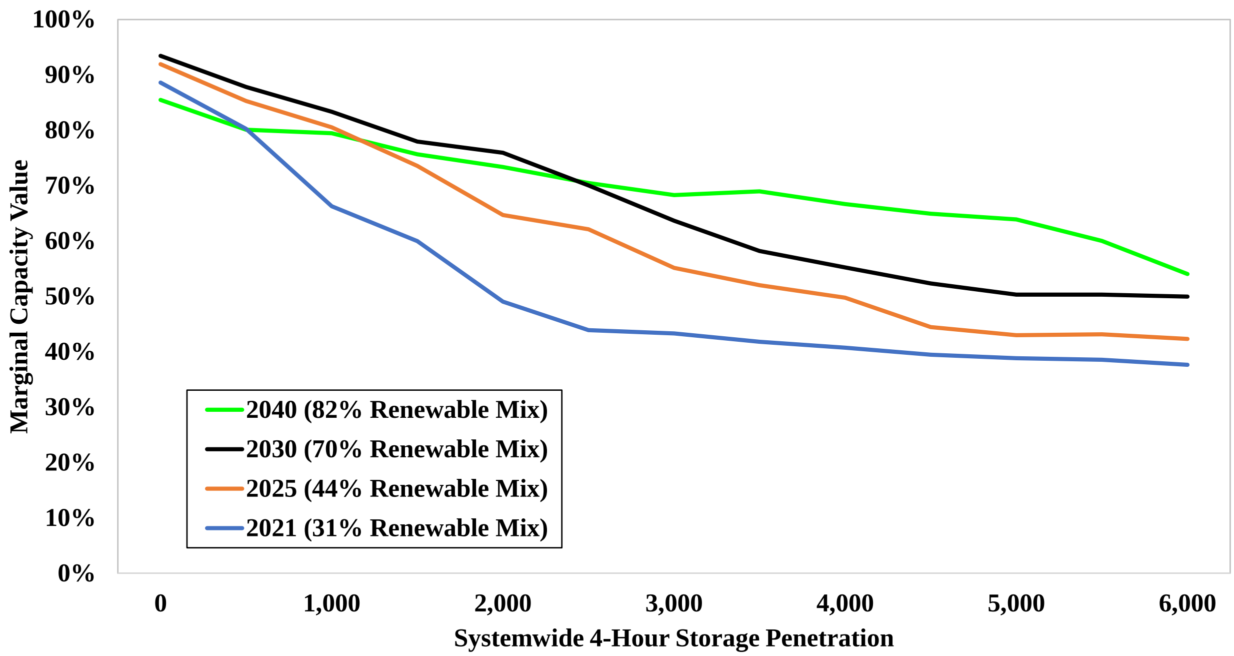

Figure 11 illustrates how capacity payments to storage are affected by its ability to support reliability. Storage of a given duration has declining marginal capacity value as its penetration increases, meaning that each additional unit of storage can reliably replace a smaller amount of conventional capacity. However, the capacity value of storage is also strongly related to the penetration of intermittent renewables, especially solar. This suggests that as renewable penetration grows, larger quantities of storage will be effective at replacing conventional capacity and will accordingly earn higher capacity payments.

The above analysis suggests that for a given level of renewable penetration, there is an efficient level of storage that can cost-effectively provide capacity value. If storage investment is low relative to renewables, storage resources will then have high capacity revenues, providing a financial incentive for additional investment. By contrast, if storage investment is inefficiently high or outpaces the level of renewable capacity that would be complementary, revenues to storage resources will fall. Market-driven storage investment thus provides greater value than arbitrary contracting requirements, which may acquire resources that provide diminishing marginal benefit, require high contract payments and reduce revenues to other storage projects.

39 This analysis is not an exact replication of NYISO's GE-MARS model and should not be taken as a forecast of precise future capacity credit values.

We have made recommendations in this report that would ensure that capacity payments to storage accurately reflect its value in replacing generation from conventional sources:

- **Recommendation #2020-4** – This would improve capacity accreditation modeling techniques for energy limited resources by ensuring that marginal capacity credit is calculated assuming a realistic dispatch pattern for storage resources.[40]
- **Recommendation #2013-1c** – This would set capacity prices based on the locational marginal price of capacity ("C-LMP"), which would create opportunities for storage investments to target areas where new capacity would be valuable. This recommendation would also reduce barriers to storage in the interconnection process by treating new and incumbent resources equally when transmission bottlenecks limit deliverability.[41]

Market Signals for Storage – Ancillary Services

Storage resources can efficiently provide ancillary services such as reserves and regulation due to their fast response times and flexible operating profiles. Figure 8 and Figure 10 show that ancillary services are expected to make up a significant share of revenues for storage projects. As intermittent generation increases, the need for system flexibility is also likely to increase. However, current reserve markets are not designed to fully price these needs and should be improved so that the value provided by flexible resources is internalized in the market.

In this report, we make the following recommendations related to NYISO's reserve market. Together, they would allow reserve procurements to keep pace with the needs of an increasingly renewable grid and efficiently compensate resources that improve system flexibility. Hence, we recommend that NYISO adopt each of the following recommendations so that storage and other flexible resources are appropriately compensated for the value they provide:[42]

- **Recommendations #2017-1** and **#2021-2** would model reserve requirements that are currently used to secure reliability in New York City load pockets and Long Island in the market software. This would increase revenues for reserve providers that can satisfy these requirements, such as storage resources interconnected in key load pockets.
- **Recommendation #2016-1** would compensate reserve providers that enable greater utilization of the transmission system. For example, storage resources that increase the amount of offshore wind energy that can be flow securely on downstate transmission lines by being prepared to inject power on short notice after a contingency would be rewarded for the congestion relief under this recommendation.
- **Recommendation #2017-2** would modify operating reserve demand curves to improve shortage pricing. This would better compensate highly flexible resources such as storage that can respond quickly to real time scarcity events.

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40 See Section XI and Section VII.E.

41 See Section XI and Sections VII.D and VII.C.

42 See Section XI. Analysis of the impact of these recommendations on revenues of flexible units can be found in Appendix VII.D.

- **Recommendation #2015-16** would adjust reserve requirements dynamically to account for variations in transmission flows. This would allow more flexible procurement of reserves in the quantities and locations where they are needed, creating opportunities for storage that can be deployed in areas where the value of holding reserves is highest.
- **Recommendation #2021-1** is to evaluate the need for additional reserves with lead time requirements of up to four hours and to consider the impact of energy limitations on a resource's eligibility to provide reserves over a given timeframe. This would potentially create additional demand for flexible resources needed to integrate renewables and encourage investment in longer-duration storage if it is needed to satisfy reserve needs.

Conclusion

Well-functioning wholesale market prices signal the levels of storage investment that efficiently support state policy goals. Importantly, when the environmental value of renewable generation is priced through a carbon price or REC payments, wholesale prices automatically pass through that value to storage resources when they facilitate renewable integration. Similarly, as renewable capacity grows, capacity and ancillary services markets will reward storage up to the levels that efficiently compensate the renewable capacity. Contracting mandates that exceed efficient levels of investment may require high contract payments and crowd out market-based storage investment when the excess projects provide diminishing marginal value.

Aspects of the NYISO markets should be improved to ensure that storage is efficiently compensated, including features of the capacity and reserve markets. With these recommendations in place, NYISO markets would create strong financial incentives to invest in storage at times and locations where it has value in integrating renewable resources.

IV. Day-Ahead Market Performance

The day-ahead market enables firms to make forward purchases and sales of power for delivery in real-time the next 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), day-ahead scheduling patterns (in subsection B), and virtual trading (in subsection C).

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

Table 2: Price Convergence between Day-Ahead and Real-Time Markets
Select Zones, 2018 - 2021

	Annual Average (DA - RT)							
	Avg. Diff				Avg. Abs. Diff			
Zone	2018	2019	2020	2021	2018	2019	2020	2021
West	0.7%	-0.1%	0.2%	1.0%	40.6%	41.3%	38.7%	35.3%
Central	-1.9%	2.8%	-0.8%	1.4%	35.1%	28.6%	29.3%	29.5%
North	-3.3%	-0.1%	-5.1%	-3.6%	55.6%	39.8%	50.2%	54.1%
Capital	-1.3%	4.2%	-0.7%	0.7%	31.8%	26.0%	25.5%	27.7%
Hudson Valley	-1.1%	3.1%	-0.2%	1.5%	31.2%	24.8%	23.7%	23.7%
New York City	-3.2%	2.4%	-3.3%	-0.6%	31.5%	25.4%	26.5%	24.0%
Long Island	1.6%	-3.0%	-0.5%	-3.8%	37.7%	37.5%	38.6%	38.7%

Day-ahead prices in 2021 were higher on average than real-time prices in most regions. Much of this day-ahead premium in the upstate regions was driven by gas market volatility in February which contributed to significantly higher congestion in the day-ahead market.

- The Capital Zone was affected by lengthy transmission outages across much of the year, especially during the Spring and Fall months, due to planned upgrades which are discussed in Section VI. This contributed to higher levels of congestion, especially in the day-ahead market.

The largest real-time premiums were in North Zone (3.6 percent) and Long Island (3.8 percent).

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

- In the North Zone, real-time price volatility has been high for several years in periods when surplus renewable generation is limited by transmission paths to central New York. Outages related to the Moses-Adirondack Smart Path Reliability Project (which will expand transmission capability to central New York) were the key driver of reduced transfer capability out of the zone. However, negative real-time pricing events in the North Zone were less severe in 2020 and 2021 than in prior years, leading to an increase in average real-time prices. This has reduced incentives to schedule virtual supply and made day-ahead prices more consistent with expected real-time prices.
- In Long Island, every month after March exhibited a real-time price premium ranging from 2 to 10 percent, with the largest values occurring in the summer months. June and August experienced particularly high real-time premiums (~10 percent) due primarily to a combination of transmission outages, high summer loads, and generators offering less flexibility after the day-ahead market.

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 imports that are low-cost or 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.

The average absolute difference between day-ahead and real-time hourly prices, a measure of real-time price volatility, was consistent in 2021 with recent years in all zones except for the North Zone and the West Zone. For the North Zone, Moses-Adirondack planned transmission outages have occurred more frequently since 2020, leading to more congestion and price volatility. The West Zone, on the other hand, exhibited improved convergence as transmission outages have become less frequent.

B. Day-Ahead Load Scheduling

Under-scheduling load generally leads to lower day-ahead prices, while over-scheduling can raise day-ahead prices above those in real-time. Table 3 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.[44]

44 Figure A-44 to Figure A-51 in the Appendix also show these quantities on a monthly basis.

Table 3: Day-Ahead Load Scheduling versus Actual Load
By Region, During Daily Peak Load Hours, 2020 – 2021

Region	Year	Bilateral + Fixed Load	Price-Capped Load	Virtual Supply	Virtual Load	Virtual Import	Virtual Export	Net Scheduled Load
West	2020	96.4%	0.0%	-5.7%	22.3%			112.9%
	2021	98.1%	0.0%	-4.4%	15.4%			109.2%
Central NY	2020	118.4%	0.0%	-32.4%	5.9%			92.0%
	2021	110.5%	0.0%	-21.0%	4.7%			94.2%
North	2020	83.9%	0.0%	-28.1%	7.5%			63.3%
	2021	80.8%	0.0%	-18.0%	7.0%			69.9%
Capital	2020	93.2%	0.0%	-10.5%	7.5%			90.2%
	2021	94.8%	0.0%	-5.7%	7.0%			96.1%
Lower Hudson	2020	73.9%	23.6%	-21.4%	12.8%			89.0%
	2021	73.7%	22.8%	-17.0%	12.5%			92.1%
New York City	2020	69.2%	25.1%	-1.1%	7.0%			100.2%
	2021	66.9%	30.8%	-1.5%	4.3%			100.5%
Long Island	2020	93.1%	0.0%	-2.9%	11.9%			102.1%
	2021	93.5%	0.0%	-1.7%	9.0%			100.9%
NYCA	2020	88.4%	10.9%	-12.4%	9.7%	-3.2%	1.1%	94.5%
	2021	86.2%	12.7%	-8.6%	7.4%	-2.9%	0.8%	95.6%

Overall, net scheduled load in the day-ahead market was roughly nearly 96 percent of actual NYCA load during daily peak load hours in 2021, up one percent from 2020. This pattern of net under-scheduling at the NYCA level is driven by several factors that reduce the incidence and severity of high real-time prices, including:

- the large quantity of available offline peaking generation and available import capability that can respond to unexpected real-time events,
- out-of-market actions (i.e,, SRE commitments and OOM dispatch) that bring online additional energy and reserves after the day-ahead market, and
- 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 slightly over 100 percent 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. While still below 100 percent, day-ahead net scheduled load rose by 6 percent to 96 percent in the Capital Zone as congestion across the Central-East interface increased from the previous year.

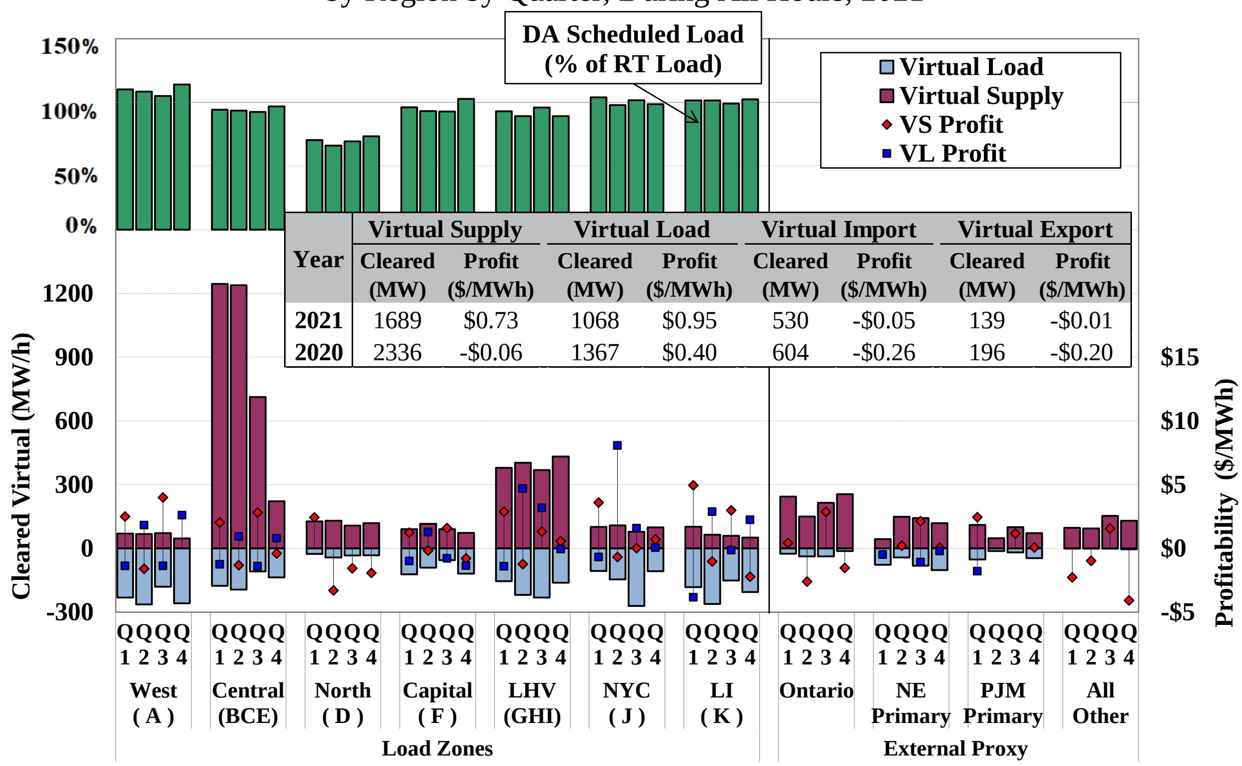
Net load scheduling was generally lower in other regions. Load was under-scheduled most in the North Zone where real-time prices can fall to very low (negative) levels when transmission bottlenecks limit the amount of renewable generation and imports from Ontario and Quebec that can be delivered south towards central New York. Despite the low levels of net scheduled load in this zone, net scheduled load increased 6.5 percentage points from the prior year. This trend reflects that there has been a reduction in the severity of negative pricing events.[45]

C. 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. Figure 12 summarizes virtual trading by location in 2021, including internal zones and external interfaces.[46]

Figure 12: Virtual Trading Activity

by Region by Quarter, During All Hours, 2021



Year	Virtual Supply		Virtual Load		Virtual Import		Virtual Export	
	Cleared (MW)	Profit ($/MWh)	Cleared (MW)	Profit ($/MWh)	Cleared (MW)	Profit ($/MWh)	Cleared (MW)	Profit ($/MWh)
2021	1689	$0.73	1068	$0.95	530	-$0.05	139	-$0.01
2020	2336	-$0.06	1367	$0.40	604	-$0.26	196	-$0.20

The general pattern of virtual trading did not change significantly in 2021 from the prior year, with the exception of the North Zone (as discussed above) and the Central Zone. Virtual supply positions in the Central Zone, along with virtual load, decreased sharply beginning in the third quarter and continuing through the fourth quarter. This pattern was driven by changes in

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[45] See section II.E of the Appendix.

[46] See Figure A-53 in the Appendix for a detailed description of the chart.

contractual relationships and their interaction with the NYISO settlement system (rather than a change in physical resource scheduling). 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 $19.4 million in 2021, indicating that they have generally improved convergence between day-ahead and real-time prices. The average rate of gross virtual profitability remained relatively low at $0.65 per MWh in 2021. In general, low virtual profitability indicates that the markets are relatively well-arbitraged and is consistent with an efficient day-ahead market.

V. 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. System operations is also important because it can have large effects on wholesale market efficiency and costs.

We evaluate eight aspects of market operations, focusing on the efficiency of scheduling and whether prices provide appropriate incentives, particularly during tight operating conditions:

- Market Performance under Shortage Conditions
- Efficiency of Gas Turbine Commitments
- Performance of 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
- Supplemental Commitment & Out of Merit Dispatch for Reliability
- Uplift from Bid Production Cost Guarantee ("BPCG") payments

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

A. Market Performance under Shortage Conditions

Prices during shortages are an important contributor to efficient long-term price signals. Shortages occur when resources are insufficient to meet the system's 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 real-time market operations and prices when the system is in the following two types of shortage conditions: [47]

[47] Emergency demand response deployments are similar to shortage conditions because they generally occur when the NYISO forecasts a reserve deficiency. See Appendix Sections V.I and VIII.C for our evaluations of demand response deployments in 2021.

- *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

Regulation shortages were the most frequent type of ancillary services shortage in 2021, occurring in 3.1 percent of intervals, which was up from the 1.8 percent of intervals in 2020. Small regulation shortages frequently occur when the system is ramp-limited because the lowest step of the regulation demand curve is $25/MW. The increased frequency reflected higher load levels, more hours of tight operating conditions, and higher energy prices (which increased the opportunity cost of providing ancillary services). Operating reserve shortages continued to occur very infrequently in 2021. While infrequent, shortages of regulation and operating reserves collectively increased average LBMPs by 3 to 6 percent in 2021.[48] 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 more efficient 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 in order to hold the unused import capability in reserve (rather than holding reserves on units inside the area). Accordingly, we recommend the NYISO modify the market models to dynamically determine the optimal amount of reserves to hold inside: [49]

- Eastern New York given flows over the Central-East Interface.
- Southeast New York given flows over the UPNY-SENY interface. Southeast New York was short of 30-minute reserves in about 45 intervals in 2021. All of these intervals had a shallow shortage that averaged just 75 MW on the 1800 MW requirement. There was sufficient head room on the UPNY-SENY interface during the vast majority of these intervals, implying that dynamic reserve allocations would eliminate those unnecessary shortages and provide more efficient price signals.
- 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

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

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

- New York City zone-level and subzone load pockets considering unused import capability into the pocket. Our analysis shows that some transfer capability from upstate to New York City was unutilized in 93 percent of intervals in 2021 when New York City had either 10-minute or 30-minute shortages.[50] Therefore, dynamic reserve requirements are needed to schedule resources more efficiently in the pocket.

The prototype analyzed by the NYISO under its *Reserve Enhancements for Constrained Areas Project* (the "RECA Study") would address these areas mentioned above. However, the prototype would not adjust the reserve requirement in the day-ahead market to consider the amount by which physical energy is under-scheduled relative to the forecast load in NYCA. Physical energy was under-scheduled by an hourly average of 750 MW in 2021.[51] Because surplus capacity on physical resources (committed in the economic pass) is sufficient on most days, the NYISO routinely holds large amounts of operating reserves on capacity that is not scheduled in the day-ahead market and, thus, not obligated to buy fuel and be available the next day. 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.[52]

Second, the operating reserve demand curves in New York are substantially lower than the value of reserves under some conditions. Efficient reserve demand curves should reflect the probability of losing load times the value of lost load ("VOLL") as reserves levels drop. Additionally, the operating reserve demand curves should be high enough to ensure that available resources are scheduled to satisfy reliability requirements (otherwise the operators will schedule such resources out-of-market). 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 13 examines the shortage pricing incentives that will be provided by NYISO compared to its neighbors with PFP rules.[53] 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 and $9,337 per MWh in 2025.[54] These payments are in addition to reserve shortage pricing, which starts at $1,000 per MWh, resulting in total incremental compensation during reserve shortages of up to $12,000 per MWh.

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

51 See Figure A-102 in the Appendix for this analysis.

52 See Recommendation #2015-16.

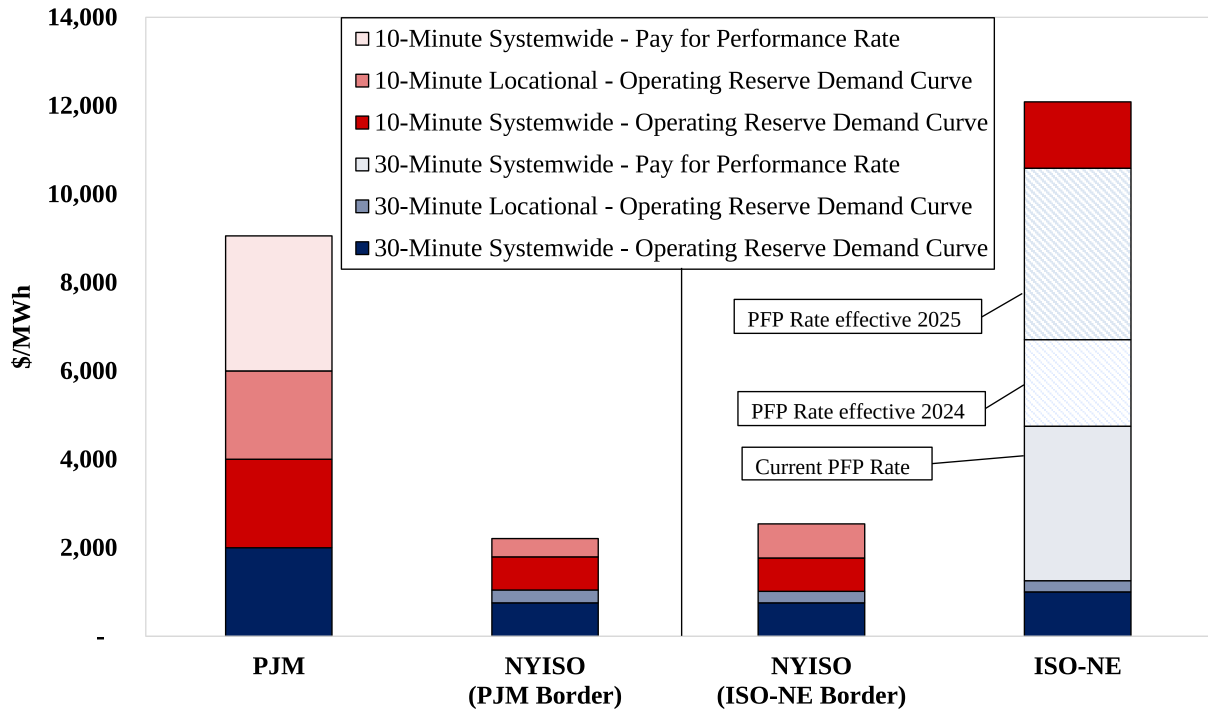
53 See Figure A-95 in the Appendix for description of this chart.

54 See ISO New England Tariff Section III.13.7.2.

- 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 are much weaker at the borders with the two markets. During shortages of 30-minute reserves, NYISO invokes statewide shortage pricing of up to $750 per MWh. During deep shortages of multiple 30-minute and 10-minute reserve requirements, NYISO invokes statewide shortage pricing levels that can exceed $2,000 per MWh under very severe conditions. Figure 13 compares shortage pricing levels in PJM and ISO-NE with NYISO including adders for locational reserve requirements near each border.

Figure 13: Shortage Pricing in NYISO vs. Neighboring Markets



During deep shortages of 30-minute reserves, NYISO shortage pricing including locational adders reaches up to $1,015 per MWh, while PJM uses $2,000 per MWh and ISO-NE uses over $4,500 per MWh during slight 30-minute reserve shortages. These disparities will increase significantly in the coming years for modest and deep reserve shortagse. 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.[55] If the NYISO reserve demand curves provided stronger incentives, these OOM actions likely would not have been necessary.

The operating reserve demand curves in New York are too low considering the willingness of NYISO operators to engage in out-of-market actions to procure more costly resources during reserve shortages. Hence, we recommend that the NYISO increase its operating reserve demand curves to levels that will schedule resources appropriately so that out-of-market actions are not necessary to maintain reliability during tight operating conditions. To ensure these levels are reasonable, the NYISO should also consider the Value of Lost Load ("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.[56]

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 2021, transmission shortages occurred in nearly 9 percent of all 5-minute 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 and 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.[57] Constraint relaxation was relatively infrequent in 2021, occurring in just 5 percent of all transmission shortages.[58]

In this report, we identify two ways in which transmission shortages are not efficiently reflected in scheduling and pricing. 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

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

56 See Recommendation #2017-2 in Section XI.

57 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.

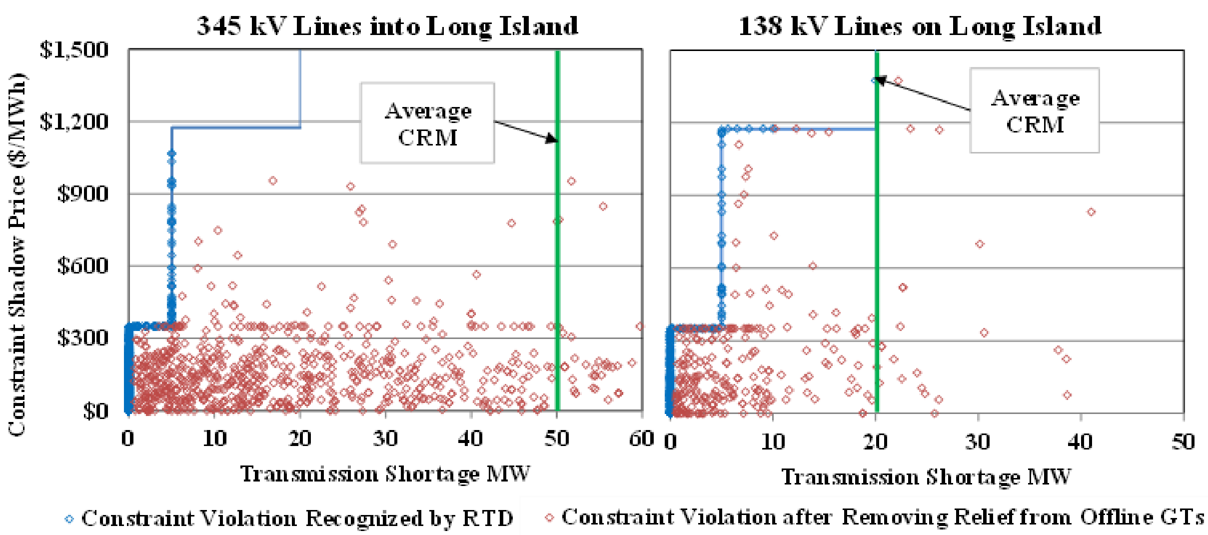
58 Since June 2017, the use of constraint relaxation for non-zero CRM constraints has been limited to shortages of 20 MW or greater after the second ($1,175 per MWh) step of the GTDC. Constraint relaxation resolves a constraint by "relaxing" the limit of the constraint—that is, automatically raising the limit of the constraint to a level that could be resolved by the market software. Constraint relaxation is evaluated in Figure A-96 .

for a large facility with a 50-MW CRM and excessively slack for a small facility with a 10-MW CRM.[59] Therefore, we have recommended replacing the current single GTDC with multiple 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.[60] The NYISO has proposed modifications to the GTDC that would be a significant improvement over the current GTDC because:[61]

- The proposed GTDC would increase more gradually than the current GTDC, which will reduce unnecessary price volatility.
- The MW-range of the proposed GTDC is based on the CRM of the constraint, which is a significant improvement over the current GTDC, which uses a 20-MW range regardless of the CRM value.

The second way that transmission shortages are not properly reflected in prices results from so-called "offline GT price-setting." This is where the real-time dispatch treats an offline GT as capable of starting in five minutes even though it is unable to do so. Consequently, the constraint shadow prices resulting from this practice are not well-correlated with the severity of transmission constraints, leading to inefficient congestion prices during such conditions. Figure 14 shows our analysis of the 345 kV and 138 kV facilities on Long Island. [62]

Figure 14: Transmission Constraint Shadow Prices and Violations
With and Without "Relief" from Offline GTs, 2021



59 See Table A-14 in the Appendix for a more detailed description.

60 Recommendation #2015-17 in Section XI.

61 See "Constraint Specific Transmission Shortage Pricing", by Kanchan Upadhyay, at August 26, 2021 ICAPWG/MIWG meeting.

62 See Figure A-97 in the Appendix for description of the chart.

"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. 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. The use of offline GT pricing likely 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.[63]

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.

Table 4 shows that the efficiency of economic GT commitments improved significantly in 2021 from prior years.[64] This is measured by the portion of the total production cost during the unit's initial commitment period (up to one hour) that is not recouped through real-time LBMP revenues. In general, lower percentage numbers indicate more efficient of scheduling and pricing. All categories of economic starts of 10-minute and 30-minute gas turbines by RTC, RTD, and RTD-CAM exhibited notable improvements in 2021 relative to 2019 and 2020. The total production costs of all economic GT starts that were not recouped through LBMP revenues reduced from roughly 16 percent each year in 2019 and 2020 to 11 percent in 2021, representing a potential 31 percent reduction in BPCG uplift in this category.

The improvement was largely driven by a change in pricing rules implemented in December 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 has led market price signals to better reflect system conditions and provide better performance incentives for flexible resources when fast-start units are deployed.

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63 See Recommendation #2020-2.

64 See Figure A-82 in the Appendix for more details of this analysis.

Table 4: Efficiency of Economic Gas Turbine Commitment
2019 - 2021

Startup Performance	Cost not Covered by LBMP Revenues		
	2019	**2020**	**2021**
< 80%	19.2%	19.9%	13.5%
>= 80%	15.6%	16.0%	10.6%
Total	**15.9%**	**16.4%**	**11.0%**

Despite these pricing improvements, there were still many commitments in 2021 when the total cost of starting gas turbines exceeded the real-time LBMP by a wide margin. There are two primary reasons:

- Divergence between RTC and RTD may lead an economic RTC-committed GT to be uneconomic in RTD.[65]
- Fast-start units often do not follow startup instructions very well, so a unit that starts late may miss the highest-priced intervals that would have made it economic to start. BPCG payments are made based on when the unit was actually running rather than when it was instructed to run (as long as the delay does not exceed 20 minutes). This is part of the reason why the table shows that better-performing units tend to recoup more of their costs than units with a start-up performance of under 80 percent. Thus, it would be beneficial to consider changes in BPCG rules to provide better incentives for performance.

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

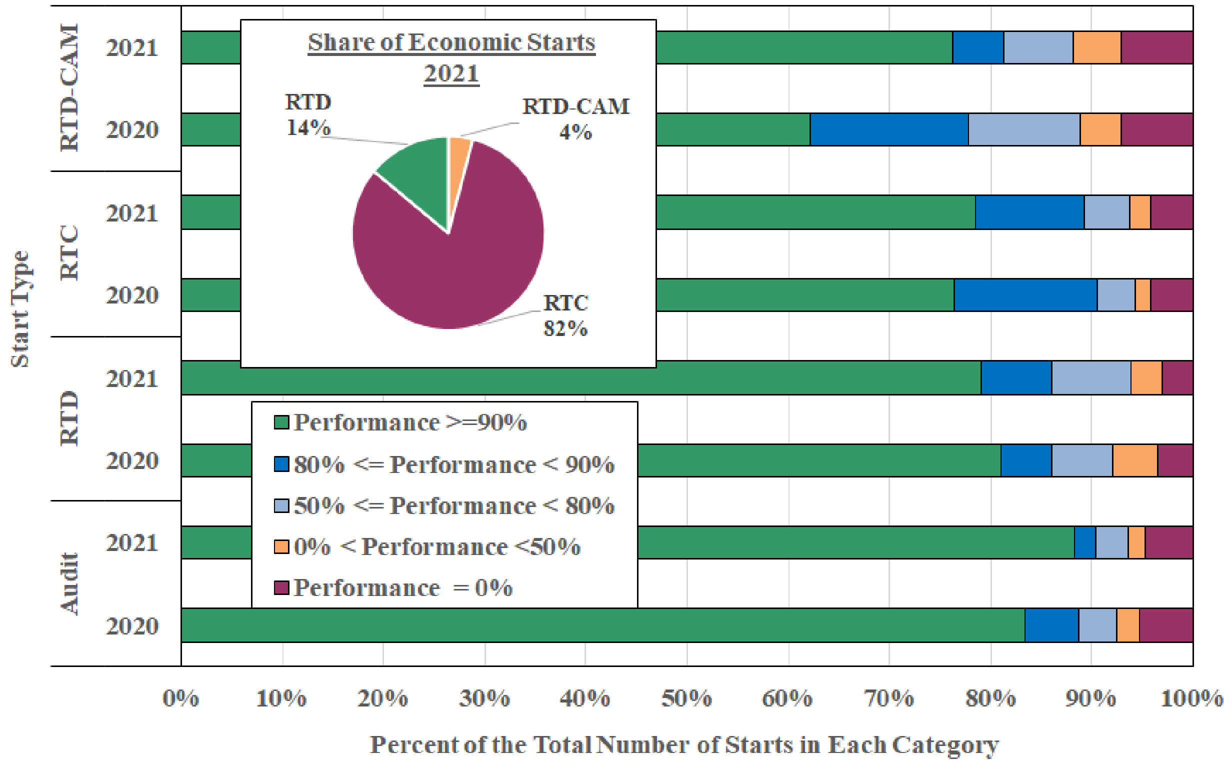
The wholesale market should provide efficient incentives for resources to help maintain reliability by compensating resources consistent with the value they provide. Efficient incentives encourage participation by demand response and investment in flexible resources in areas where they are most valuable. Over the coming decade, performance incentives will become even more critical as the entry of intermittent resources will require more complementary flexible resources. This section analyzes the performance of gas turbines in responding to start-up instructions in the real-time market.

Figure 15 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 2020 and 2021.[66] The figure also compares the performance for each economic start category to the performance of the associated units in the NYISO auditing process.

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

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

Figure 15: Average GT Performance by Type after a Start-Up Instruction
Economic Starts vs Audit, 2020-2021



Gas turbines exhibited a wide range of performance in responding to start-up instructions in recent years. Gas turbines exhibited worse average performance during RTD-CAM starts than during RTC and RTD starts in recent years, although average performance during RTD-CAM starts improved modestly in 2021. In 2021, approximately 19 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. This was higher than the 11 to 14 percent in the same performance category (including 3 to 4 percent that failed to start) during RTC and RTD starts. Although RTD-CAM starts accounted for just 4 percent of all economic starts in 2021, 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 2020 and 2021 with a modest improvement among several 10-minute GTs in 2021. Despite some variations in each year from 2019 to 2021, the overall GT startup performance has been significantly better than before 2018 due a large part to retirements and IIFOs of some poor performing units. This trend will likely continue as older units continue to leave the market.

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 since 2020. There were 251 audits (on 136 unique GTs) in 2020 and 256 audits (on 126 unique GTs) in 2021, 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 disqualify poor performers or otherwise motivate good performance. The NYISO is considering rule changes that would provide stronger incentives for reliable performance.[67]

The increased focus on auditing over the last two years has not significantly improved GT start performance. Several units that performed very well in audits only had an average performance of 60 percent or less when responding to start-up instructions from the market model. Audits of a unit's capability do not provide incentives to follow instructions under normal conditions. Gas turbines miss out on energy revenues when they fail to start or start late, but there is no mechanism for discounting operating reserve revenues of gas turbines that do not perform well on average. Consequently, some gas turbines that tend to perform poorly still earn most of their net revenue from the sale of operating reserves.[68] Since operating reserve revenues are not affected by suppliers' performance, the market does not provide efficient performance incentives to reserve providers. In addition, when gas turbines are committed economically but start late, they are less likely to operate during a period when prices are high enough for them to recoup their costs, but they still receive the same cost guarantee (if they do not start more than 20 minutes late). Hence, the current BPCG rules tend to mute the incentive to perform reliably.

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

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67 See *Reserve Pick Up Penalty Concepts* at April 6, 2022 MIWG meeting.

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

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 803 MW of duct-firing capacity in the summer and 848 such MW in the winter, collectively.[69] However, some duct-firing capacity is not always capable of following a five-minute dispatch signal.

We show an example of a combined-cycle unit in the Appendix that could not follow dispatch instructions during a Reserve Pickup (RPU) event, illustrating its inability to fire the duct burner within the 10-minute timeframe.[70] However, this duct burner capacity is treated as capable of following 5-minute dispatch signals in the market scheduling and pricing software. We estimate that, in the afternoon peak hours (HB16-HB20) of 2021, on average: [71]

- 111 MW was offered but not capable of following 5-minute ramping instructions;
- 59 MW was scheduled for but not capable of providing 10-minute reserves; and
- 16 MW was scheduled for but not capable of providing regulation.

These disconnects can present challenges in real-time operations especially when the duct-firing capacity becomes more valuable under tight system conditions such as in an RPU event.

The inflexibility of duct-firing capacity leads to several additional problems related to 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. We estimate that an average of 55 MW of duct-firing capacity was unvailable in afternoon peak hours (HB16-HB20) for this reason in 2021.[72]
- Reduced regulation offers – Some combined cycle units do not offer regulation in the real-time market because they 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.[73]
- Reduced ramping and operating reserve offers – Some combined cycle units offer very conservative ramp rates for normal energy dispatch and operating reserves. A single value *Emergency Response Rate* is used for operating reserves scheduling and is required to be greater than or equal to all *Normal Response Rates* that are used for normal energy dispatch. When units face the risk of providing operating reserves in the duct-firing

69 See Table A-9 in the Appendix.

70 See Figure A-83 in the Appendix.

71 See Figure A-84 in the Appendix.

72 See Figure A-84 in the Appendix.

73 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.

range, they may offer both emergency and normal response rates far below their true capability in the non-duct range in order to comply with this requirement.

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.[74] Ideally, this would: (a) economically commit and decommit duct-firing capacity using RTC as is done for gas turbine peaking units; (b) allow duct-firing capacity to be scheduled appropriately for reserves, and (c) allow generators to submit offers that limit their regulation range to exclude the duct-firing capacity. The NYISO is pursuing the *Improve Duct-Firing Modeling Project* to explore changes that may address the issues discussed above.[75] The project's target deliverable is a Market Design Concept Proposed in the third quarter of 2022.

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 LTE after a contingency.[76] 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 2021, 66 percent (or $28 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

74 See Recommendation #2020-1 in Section XI.

75 See 2022 Market Project *Improve Duct-Firing Modeling*.

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

Table 5, the additional transfer capability above LTE on New York City transmission facilities averaged: (a) 11 to 66 MW (or 5 to 28 percent of individual LTE ratings) for 138 kV load-pockets; and (b) 153 to 292 MW (or 18 to 31 percent of individual LTE ratings) for the 345 kV system during congested real-time intervals in 2021.[77]

Table 5: Modeled Limits vs Seasonal Limits for Select New York City N-1 Constraints
In the Real-Time Market, 2021

Transmission Facility		Average Constraint Limit (MW)		
		N-1 Limit Used	Seasonal LTE	Seasonal STE
345 kV	Dunwodie-Motthavn	986	833	1298
	Farragut-E13th ST	1127	935	1345
	W49th ST-E13th ST	1210	986	1566
	Goethals-Gowanus	951	748	1241
	Sprnbrk-W49th ST	1236	944	1529
138 kV	Gowanus-Greenwd	316	291	341
	Vernon-Greenwd	238	226	248
	Foxhills-Greenwd	304	239	371

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 congestion component of the clearing price as is done with energy producers.[78] Section V.M of the Appendix provides a potential mathematical formulation that might be used to schedule and compensate these reserve providers efficiently. Likewise, the NYISO should also provide 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 of generation after a natural gas supply 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 non-controllable AC

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

78 Recommendation #2016-1 in Section XI.

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 6 evaluates the consistency of the direction of power flows on non-optimized PAR-controlled lines and LBMP differences across these lines in 2021. 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.

Table 6: Efficiency of Scheduling on Non-Optimized PAR Controlled Lines[79, 80]

2021

	Day-Ahead Market Schedule				Adjustment in Real-Time			
	Avg Flow (MW)	Avg NYCA Price minus Avg Outside Price ($/MWh)	Percent of Hours in Efficient Direction	Estimated Production Cost Savings (Million $)	Avg Flow (MW)	Avg NYCA Price minus Avg Outside Price ($/MWh)	Percent of Hours in Efficient Direction	Estimated Production Cost Savings (Million $)
Ontario to NYCA								
St. Lawerence					-19	$1.63	51%	$0.6
New England to NYCA								
Sand Bar	-49	-$21.18	97%	$10	0.1	-$19.89	56%	$0.4
PJM to NYCA								
Waldwick	85	$5.06	81%	$4	45	$4.14	54%	-$1
Ramapo	333	$6.23	89%	$17	110	$5.83	69%	$5
Goethals	39	$6.79	83%	$2	98	$6.59	63%	$1
Long Island to NYC								
Lake Success	107	-$10.38	16%	-$7	4	-$11.95	37%	$2
Valley Stream	72	-$10.60	2%	-$5	-1	-$11.55	42%	-$0.1

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 a small portion of hours in the day-ahead market in 2021. This is primarily because prices on Long Island were typically higher than those in New York City where the 901

79 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.

80 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.

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.

Power across the Lake Success PAR-controlled line (“903” line) was scheduled in the day-ahead market in the efficient direction far more frequently in 2021 than in 2020 (when it was in the efficient direction in just 2 percent of hours). In 2021, most hours when flows were scheduled in the efficient direction occurred during the period when both the Y49 and Y50 lines were out of service. When the Y50 line is out of service, the ConEd-LIPA wheeling agreement does not require that the 901 and 903 lines be used to flow power from Long Island to New York City.[81]

The transfers across the 901 and 903 lines:

- Increased production costs by $10 million in 2021 (and $13 million in 2020). The increase in production costs in 2021 would have been even higher without lengthy Y49 and Y50 outages.
- 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 426 thousand tons of CO_2 and 606 tons of NOx pollution in non-attainment areas in 2021. Hence, the inefficient operation of these lines accounted for 8 percent of NOx pollution from NYISO power plants in non-attainment areas in 2021.
- 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.[82] Although this should benefit both parties in aggregate, it may financially harm one party. Hence, a new financial settlement mechanism is needed to ensure that both parties benefit from the changes.[83] We recommend the NYISO work with the parties to this contract to explore changes that would allow the lines to be used more efficiently.[84]

81 The scheduling efficiency on the 901 line did not show a similar increase because the 901 line was scheduled to flow zero MW of power during the period when both Y49 and Y50 were out of service.

82 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.

83 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.J of the Appendix.

84 See Recommendation #2012-8 in Section XI.

The PAR-controlled lines between PJM and the NYISO are operated under the M2M JOA to be responsive to market price signals, although the scheduling efficiency varied among these lines.[85,86] Operation of the Ramapo PAR-controlled ("5018") line was most efficient, while operation of the Waldwick PAR-controlled ("J" and "K") lines was much less active and efficient. Although the assumed operations over these M2M PARs all led to production cost savings in the day-ahead market for a total of $23 million in 2021, the impact of their real-time operations was mixed. The J and K lines accounted for a $1 million net *increase* in production costs in real time, while the 5018 line and the Goethals PAR-controlled ("A") line accounted for a net *reduction* of $5 million and $1 million, respectively. Section VI evaluates the impacts of these lines on congestion management.

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 2021.[87] 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 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.

G. Supplemental Commitment & Out of Merit Dispatch for Reliability

Supplemental commitment occurs when a unit is not committed economically in the day-ahead market, but is needed for local or systemwide reliability. There are several types of supplemental commitment:

- ***Day-Ahead Reliability Units ("DARU")*** commitment occurs at the request of transmission owners or the NYISO for reliability before the day-ahead market;
- ***Day-Ahead Local Reliability Rule ("LRR")*** commitment occurs to meet a local reliability need within the economic commitment within the day-ahead market;
- ***Supplemental Resource Evaluation ("SRE")*** commitment occurs at the request of transmission owners or the NYISO for reliability after the day-ahead market closes; and

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85 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.

86 See Appendix Section V.D provides an analysis of the PAR-control actions taken for each of these lines.

87 See Section VIII.C for a more detailed discussion on factors causing RTC and RTD divergence.

- ***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.

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 16 summarizes the quantities of four types of reliability commitment (i.e., DARU, LRR, SRE, and Forecast Pass) by region in 2020 and 2021.[88] Roughly 550 MW of capacity was committed on average for reliability in 2021, down 11 percent from 2020. New York City continued to account for most (80 percent) reliability commitments in 2021, although these fell 19 percent from 2020. Reliability commitments in New York City for N-1-1-0 requirements have fallen in recent years because of several procedural improvements by the NYISO and ConEd. First, procedural changes implemented in the first quarter of 2020 reduced supplemental commitments at the Arthur Kill plant when it was not actually needed for local reliability. Second, the NYISO expanded the use of hourly (rather than daily) requirements to additional load pockets in July 2020, which reduced the amount of unnecessary LRR commitments in off-peak hours. Third, ConEd and NYISO began using 300-hour ratings rather than normal ratings for N-1-1-0 requirements in January 2021, further reducing reliability commitments.

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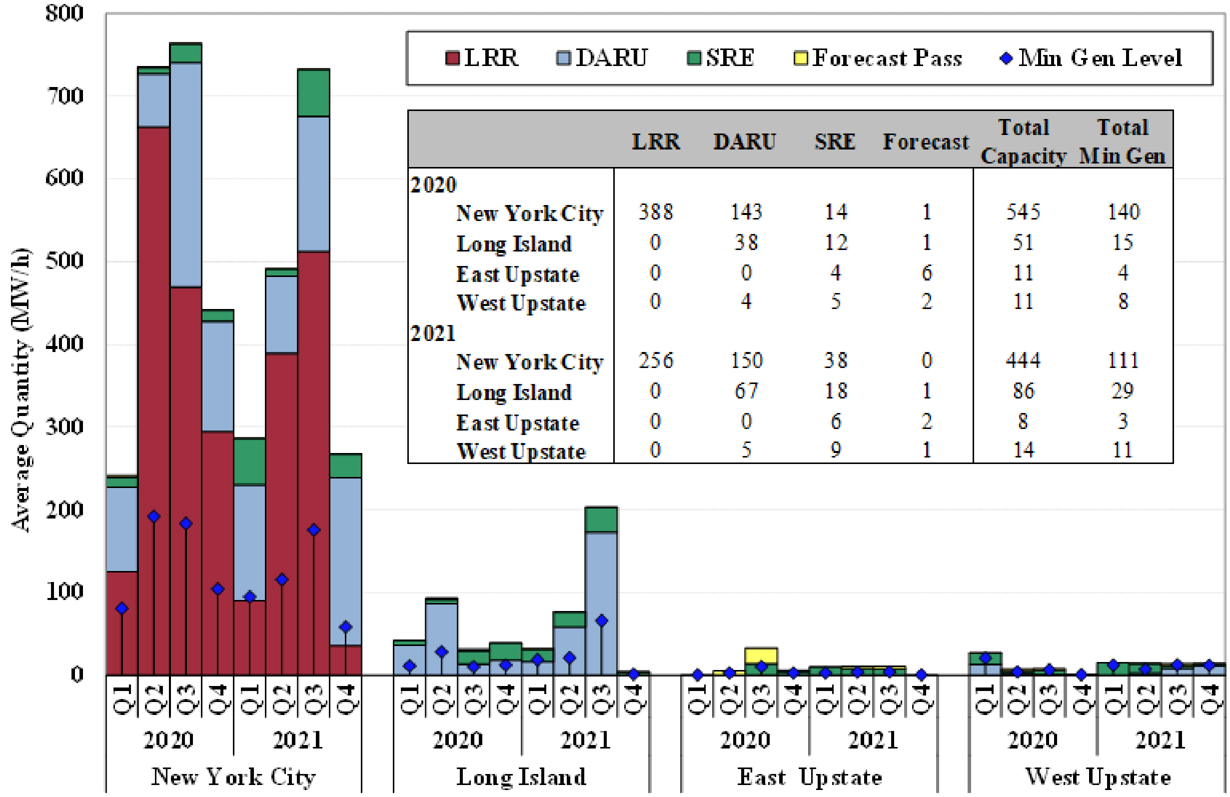
88 See Section V.J in the Appendix for a description of the figure.

Figure 16: Supplemental Commitment for Reliability in New York

By Category and Region, 2020-2021



	LRR	DARU	SRE	Forecast	Total Capacity	Total Min Gen
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
2021						
New York City	256	150	38	0	444	111
Long Island	0	67	18	1	86	29
East Upstate	0	0	6	2	8	3
West Upstate	0	5	9	1	14	11

Despite these improvements, excess reliability commitments continue to occur for the NOx Bubble requirements in New York City.[89] Specifically, a steam turbine was committed solely to satisfy the NOx rule on 63 days during the Ozone season in 2021, and these NOx-only steam turbine commitments could have been avoided on 50 days if the NYISO and ConEd were allowed to consider whether the GTs were actually needed for reliability (before committing the associated steam turbine).[90] The current NYSRC rules require the commitment of the associated steam turbine during the Ozone Season regardless of whether the GTs are actually needed. 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.

Reliability commitments in other areas were much less frequent in 2021, although DARU commitments rose noticeably on Long Island in the third quarter for local reserve needs. This is discussed next in more detail.

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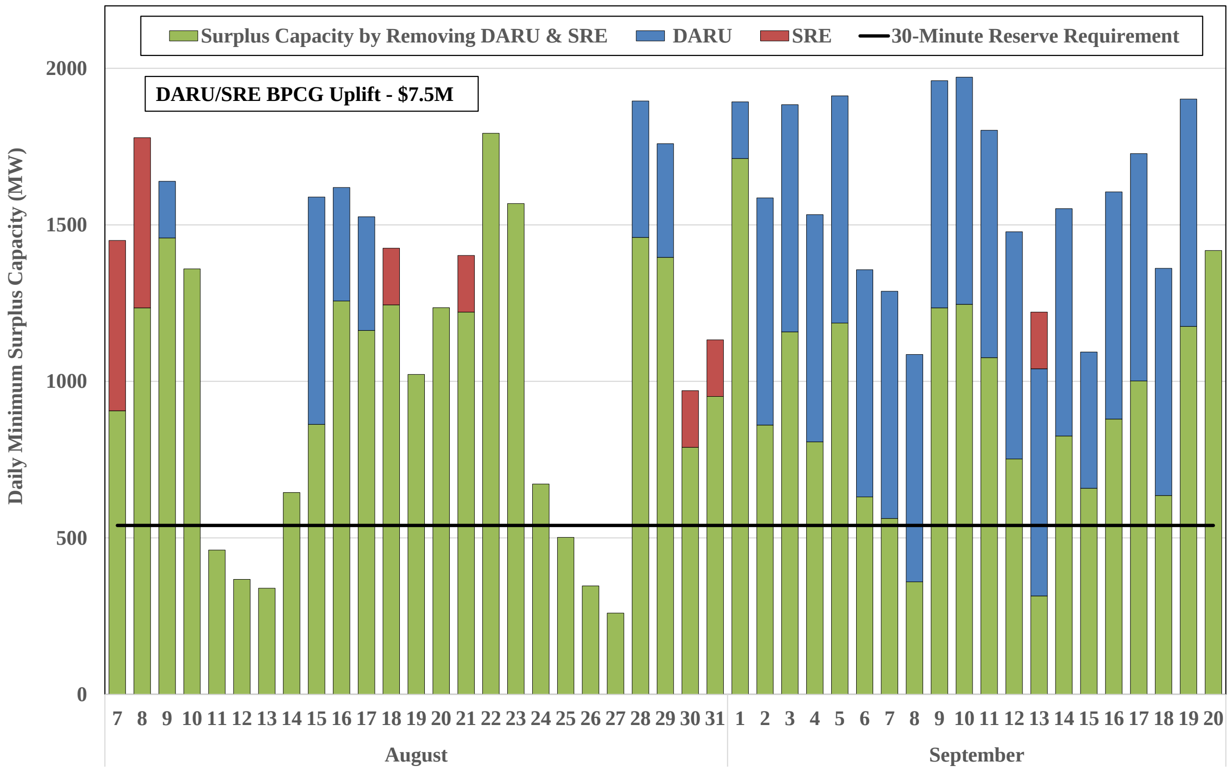
89 See Figure A-100 in the Appendix for more information about this analysis.

90 This would require the NYSRC to revise Application of Reliability Rule #37.

Supplemental Commitment on Long Island

Figure 16 shows that reliability commitments on Long Island rose significantly in the third quarter of 2021. This occurred primarily during the period from August 7 to September 20 when both 345kV tie lines between upstate and Long Island (i.e., Y49 & Y50 lines) were out of service, leaving Long Island to rely heavily on internal generation resources to serve load. Figure 17 shows our evaluation of supplemental commitments on Long Island during this period.

Figure 17: Supplemental Commitment on Long Island
During Y49 & Y50 Outages, 2021



The figure compares the daily minimum surplus capacity on Lond Island to the reserve requirement procured through the market system. The total of the stacked bars, calculated as the total amount of bid UOL from online and offline available quick-start resources minus generation output, represents the minimum hourly surplus capacity on Long Island for each day of the examined period. This excludes any unutilized transfer capability across ties into Long Island (including 901/903, 1385, CSC, and Neptune lines). The red and blue bars represent the bid UOL from resources that are either SRE- or DARU- committed. The black line shows the maximum 30-minute reserve requirement on Long Island, which is set at 540 MW currently in the day-ahead and real-time market.

This analysis reveals two significant market inefficiencies. First, the reserve requirement for Long Island is understated. The figure shows that out-of-market commitments occurred on 31 days during this period to maintain adequate reserves, indicating that the current 540 MW of maximum 30-minute reserve requirement is sometimes inadequate to maintain reliability. The current Long Island reserve requirement is usually adequate to maintain security and reliability following the largest contingency, but it is not necessarily adequate to satisfy N-1-1-0 criteria (i.e., normal line loading following the two largest contingencies). Because this requirement is not included in the market software, system operators had to relied on OOM commitments when needed. When reserve requirements are satisfied with OOM actions, it leads to understated prices and poor incentives for suppliers. Modeling reserve requirements in the Long Island load pockets where these OOM actions are used would improve efficiency and encourage new resources to locate where they are most valuable. Hence, we recommend that the NYISO implement local reserve requirements in Long Island that are adequate to maintain reliability rather than rely on out-of-market actions.[91]

Second, although the day-ahead and real-time markets schedule resources to satisfy reserve requirements on Long Island, reserve providers 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. The figure shows that Long Island was short of 30-minute reserves (i.e., when the height of stacked bars is lower than the black line) on six days. But the 30-minute reserves clearing prices were zero on four of these days and were at levels that do not properly reflect Long Island shortages on the other two days. Compensating reserve providers in accordance with the market scheduling decisions would improve market incentives, providing better signals to new investors over the long term. Hence, we recommend the NYISO set day-ahead and real-time reserve clearing prices considering reserve constraints for Long Island.[92] This is particularly important if our recommendation to model local reserve requirements in Long Island load pockets is adopted. The NYISO is currently performing a study of dynamic reserve scheduling that recommended considering pricing of Long Island reserves.[93]

Forecast Pass Commitment

Forecast pass commitments were infrequent, and the amount of committed capacity was modest on most of these days. Nonetheless, we identified two issues in this process. First, we found that some quick-start capacity is treated as slow-start capacity in the Forecast Pass. Consequently, most of the FCT commitments would not have occurred if these quick-start units were

91 See Recommendation #2021-2.

92 See Recommendation #2019-1.

93 See *Dynamic Reserves: Project Kick-off* slide 6, presented on March 3, 2022 to the Market Issues Working Group.

recognized as quick-start by the software.[94] Software changes would be necessary to correct this issue.

Second, our evaluation showed that the physical energy and reserves scheduled in the day-ahead market was significantly lower than the forecasted load and reserve needs on most days.[95] Thus, the NYISO holds large amounts of 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.[96] In some cases, the operating reserve requirements could be satisfied with resources having lead times longer than 30 minutes (rather than 10-minute and 30-minute reserve providers). Accordingly, we have recommended that the NYISO evaluate the need for longer leadtime reserve products.[97] However, before longer lead time reserve products have been created, it may be that the most efficient way to represent such requirements in the market is with a 30-minute reserve requirement. The NYISO should consider these tradeoffs in its evaluation of dynamic reserves.

Price Effects of Modeling N-1-1-0 Reserve Constraints in New York City

Reliability commitments frequently occur for local load pocket reliability (i.e., N-1-1-0 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 is reasonably efficient for the marginal commitment needed to satisfy the needs of the pocket, the use of BPCG payments does not provide efficient incentives for lower-cost resources 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-1-1-0 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-1-1-0 requirements in New York City, we estimated the clearing prices that would have occurred in 2021 if the NYISO were

[94] See Section V.G in the Appendix for more information about this analysis.

[95] See Figure A-102 in the Appendix for more information about this analysis.

[96] See Recommendation #2015-16.

[97] See Recommendation #2021-1.

to devise a day-ahead market reserve requirement.[98] Table 7 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.

Table 7: Day-ahead Reserve Price Estimates
Selected NYC Load Pockets, 2021

Area	Average Marginal Commitment Cost ($/MWh)
NYC 345 kV System	$2.34
Selected 138 kV Load Pockets:	
Astoria West/Queensbridge	$3.64
Vernon	$3.20
Freshkills	$3.35

Based on our analysis of operating reserve price increases that would be necessary to represent the marginal costs of satisfying N-1-1-0 requirements in the day-ahead market, we find such price increases would range from an average of $2.34 per MWh in most areas to as much as $3.64 per MWh in the Astoria West/Queensbridge load pocket in 2021. 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-1-1-0 constraints in New York City load pockets, which would provide an efficient market mechanism to satisfy reliability criteria at these locations.[99] 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 7. 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.[100] NYISO is considering modeling New York City load pockets as part of its 2022 *Dynamic Reserves* project, and the prototype analyzed by NYISO in the RECA Study would allow those requirements to be set dynamically. This effort has potential to greatly improve the pricing of energy and reserves in NYC load pockets and other constrained areas in the system. This will become particularly important when offshore wind is added to New York City because it will allow the NYISO to utilize the wind output to free up interface capability into the load pockets that can hold reserves.

98 Section V.J in the Appendix describes the methodology of our estimation.

99 See Recommendation #2017-1 in Section XI.

100 See analysis in Section VII.D.

Out of Merit Dispatch

Table 8 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.[101]

Table 8: Frequency of Out-of-Merit Dispatch
By Region, 2020 - 2021

Region	OOM Station-Hours		
	2020	2021	% Change
West Upstate	115	191	66%
East Upstate	107	587	449%
New York City	143	542	279%
Long Island	4335	2316	-47%
Total	**4700**	**3636**	**-23%**

The quantity of OOM dispatch fell 23 percent from 2020 to 2021. The reduction was driven primarily by the decrease on Long Island, where OOM actions to manage post-contingency flow on 69 kV facilities were greatly reduced after the NYISO started to incorporate 69 kV constraints in the day-ahead and real-time markets in April 2021.

OOM dispatch increased modestly in other regions when transmission outages were taken to facilitate transmission upgrade projects.[102] These outages led to more frequent transmission bottlenecks in the nearby areas, requiring more frequent OOM dispatch to manage constraints that are not secured or not fully represented in the market. A significant portion of OOM actions in the North Zone and the Capital Zone were OOM commitments to maintain adequate reserves for the N-1-1 requirements in relevant local load pockets, which are not modeled in the day-ahead and real-time markets. Modeling these local reserve needs in the market system would help improve the efficiency of scheduling and pricing and would help attact investment to such areas.

On Long Island, OOM actions occurred mostly in the summer months when high-cost peaking resources were used out-of-market to manage congestion on the 69 kV network and Transient Voltage Recovery ("TVR") needs on the East End of Long Island. The NYISO has an on-going process to evaluate and incorporate additional 69 kV constraints into the market models, which should help further reduce such OOM needs on Long Island. However, this does not address the

101 Figure A-105 in the Appendix provides additional detail in 2020 and 2021 for each region.

102 These include the Empire State Line Project in Western New York, Smart Path Reliability Project in Northern New York, Central East Energy Connect Project from Western to Eastern New York, and New York Energy Solution Project in Eastern New York.

TVR requirements on the East End of Long Island. Hence, we recommend NYISO model East End TVR needs (using surrogate constraints) in the market software.[103] We illustrate in the Section III.E in the Appendix one approach to develop surrogate constraints that could be used to satisfy TVR constraints within the market models.

H. Guarantee Payment Uplift Charges

The NYISO recovers its additional payments to certain market participants that are not recouped from LBMP and other market revenues (to guarantee full as-bid costs) through guarantee payment uplift charges. It is important to minimize these uplift charges because they are difficult to hedge and do not provide transparent economic signals to market participants and potential investors. When the markets reflect reliability requirements and system conditions efficiently, uplift charges should be relatively low.

Figure 18 shows guarantee payment uplift for four local reliability categories and three non-local reliability categories in 2020 and 2021 on a quarterly basis.[104] The figure shows that guarantee payment uplift totaled $54 million in 2021, up 28 percent from 2020. The increase was driven primarily by higher gas prices, which increased the commitment cost of gas-fired units, and was partially offset by reduced supplemental commitments and OOM dispatch and enhanced fast-start pricing.

New York City accounted for $26 million (or 48 percent) of BPCG uplift in 2021, up 37 percent from 2020. Over $19 million was paid to generators that were committed for N-1-1-0 local requirements despite the reduction of such commitments for the reasons discussed in the previous subsection. We have recommended the NYISO model local reserve requirements to satisfy these N-1-1-0 needs, which should greatly reduce associated BPCG uplift and provide more transparent and efficient price signals.[105]

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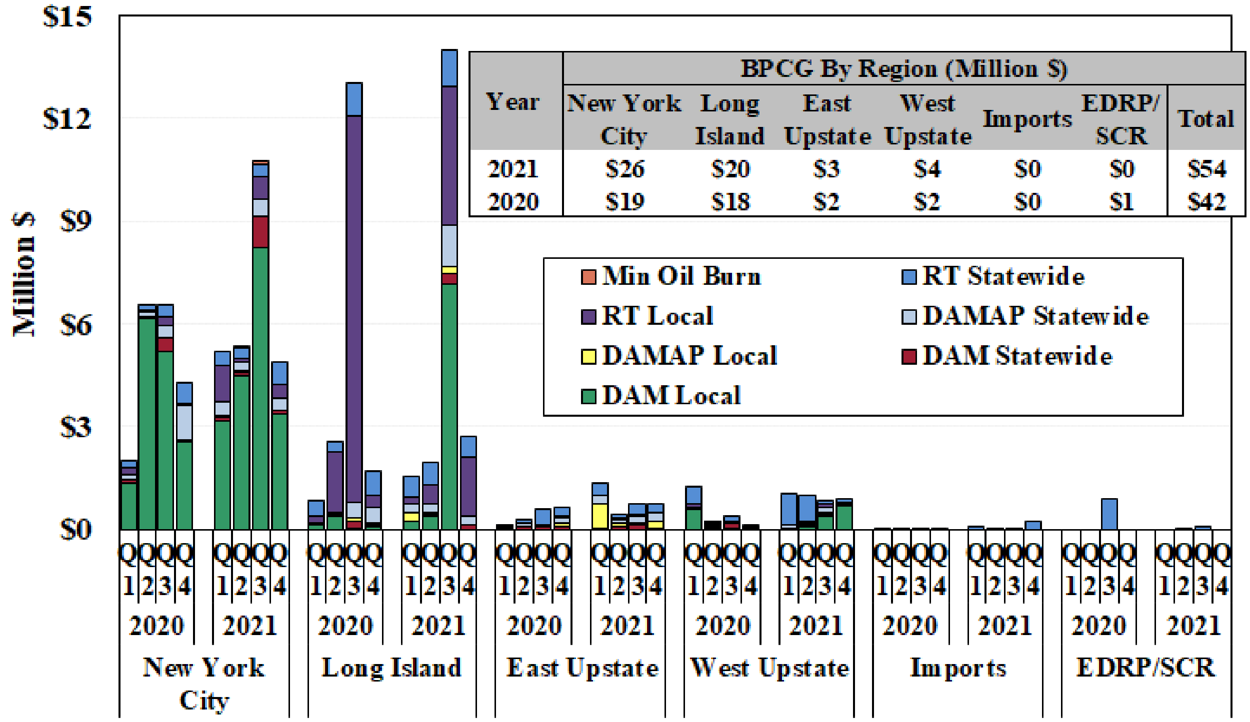
[103] See Recommendation #2021-3.

[104] See Figure A-106 and Figure A-107 in the Appendix for a more detailed description of this analysis.

[105] See Recommendation #2017-1.

Figure 18: Uplift Costs from Guarantee Payments in New York
By Category and Region, 2020 – 2021



Long Island accounted for $20 million (or 37 percent) of BPCG uplift in 2021, up 11 percent from 2020. More than $7 million was paid to generators that were committed to satisfy N-1-1-0 requirements for Long Island. We have recommended the NYISO implement reserve requirements in Long Island that are adequate to maintain reliability rather than rely on out-of-merit actions.[106] Another $7 million was paid in the category of real-time local BPCG uplift primarily to high-cost peaking resources that were OOMed frequently in the summer months to manage 69 kV congestion and local TVR needs (for the reasons discussed in the previous subsection). We have recommended the NYISO consider modeling local TVR requirements on Long Island in the day-ahead and real-time markets.[107] 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.[108]

BPCG uplift payments in other regions were moderate, totalling roughly $7 million in 2021. Most of this was paid to units that were either supplementally committed or dispatched out-of-

106 See Recommendation #2021-2.

107 See Recommendation #2021-3.

108 See Section VI.B for this analysis.

merit to manage non-market-secured transmission constraints or local reserve needs. It would be beneficial to incorporate more of these requirements in the market systems.

VI. 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 2021:

- 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 Appendix Section III, while the Market Operations section evaluates elements of congestion management.[109]

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.[110] 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 rather than in the day-ahead and real-time markets are evaluated in subsection B.

Figure 19 evaluates overall congestion revenues and shortfalls in the past two years, showing monthly summaries of:

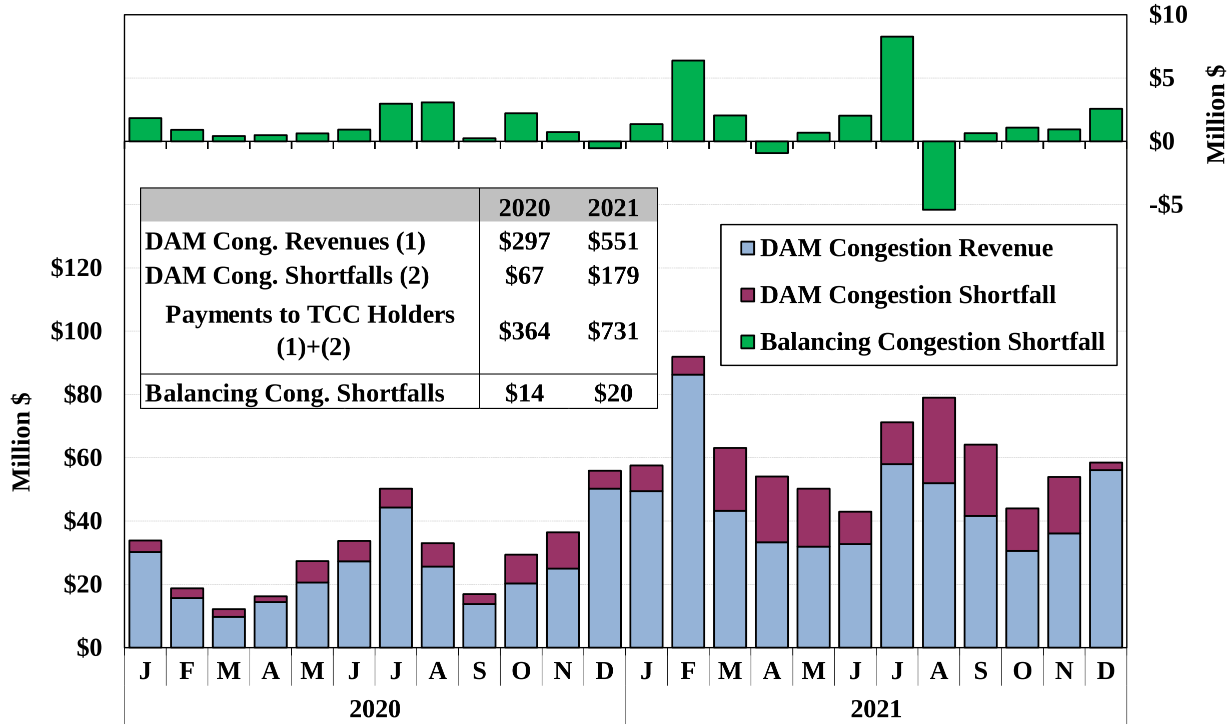
- Day-ahead Congestion Revenues – These are collected by the NYISO when power is scheduled to flow across congested transmission lines in the day-ahead market.

109 The Market Operations section evaluates pricing during transmission shortages (V.A), use of reserves to manage NYC congestion (V.E), and coordinated congestion management with PJM (Appendix V.C).

110 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 the amount that can flow in real time. These shortfalls highlight outages, modeling inefficiencies, and other operational factors that reduce transmission capability significantly from levels expected in the day-ahead market.

Figure 19: Congestion Revenues and Shortfalls
2020 – 2021



Day-ahead congestion revenues, day-ahead congestion shortfalls, and balancing congestion shortfalls all rose from 2020 to 2021, by 86 percent, 168 percent, and 42 percent, respectively. We discuss these increase in the subsections below.

Day-Ahead Congestion Revenues

The substantial increase in day-ahead congestion revenues in 2021 was partly due to the unusually low congestion levels in 2020 because of low load levels, infrequent peaking conditions, and low natural gas prices during the COVID-19 pandemic.[111] Congestion levels in 2021 were more only modestly higher than in recent years preceding 2020. Higher natural gas prices and gas price spreads between regions, which increase redispatch costs to resolve congestion, were one of the main drivers of elevated congestion levels in 2021. Natural gas prices rebounded in 2021 after being at their historical low levels in most of 2020. Natural gas prices climbed to their highest monthly averages since 2015 in the second half of 2021 partly because gas shortages and spiking prices in Europe and Asia have increased demand for U.S. LNG exports and gas prices in the U.S domestic market as well.

Another key driver of increased congestion was more frequent transmission outages affecting the Central-East interface. Central-East interface transfer capability was reduced by 800 to 1000 MW in the shoulder months and by nearly 200 MW in the summer months because of transmission line outages that were taken for the Central East Energy Connect project.[112] In addition, Central-East congestion has generally increased as a result of the retirement of the Indian Point 2 in April 2020 and Indian Point 3 in April 2021. As eastern New York has become more reliant on natural-gas fired generation, spikes in congestion because of tight gas market conditions on cold winter days have become more frequent. As a result, Central-East congestion rose from 38 percent of day-ahead congestion in recent years to 56 percent in 2021.

Long Island congestion also rose significantly in 2021, accounting for 12 percent of day-ahead congestion revenues. One reason for this increase was that NYISO started to model two 69 kV constraints on Long Island in late April 2021, which accounted for 26 percent of the day-ahead congestion revenues in 2021 on Long Island. This is a more efficient way to manage congestion than through out-of-market actions taken previously by system operators. A second key factor wasa that Long Island also experienced unusually severe transmission outages in 2021. One of the two 345 kV lines from upstate to Long Island (i.e., the Y49 & Y50 lines) was out of service on roughly 190 days, and both lines were out of service on 46 days during summer peak periods. These lengthy outages led to much more severe congestion and prices on Long Island.

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

111 The year of 2020 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).

112 This is also referred to as the Public Policy Tranmission Project Segment A, which involves: (a) construction of a new 345 kV line from Edic to New Scotland on existing right-of-way (primarily using Edic to Rotterdam right-of-way west of Princetown); (b) construction of two new 345 kV lines from Princetown to Rotterdam on existing Edic to Rotterdam right-of-way; (c) decommissioning of two 230 kV lines from Edic to Rotterdam; and (d) related switching or substation work at Edic, Princetown, Rotterdam and New Scotland.

9 shows total day-ahead congestion shortfalls for selected transmission facility groups.[113] Day-ahead congestion shortfalls rose significantly from $67 million in 2020 to $179 million in 2021. This was primarily due to more planned transmission outages and, to a lesser degree, more forced transmission outages. We discuss these shortfalls by transmission path below

Table 9: Day-Ahead Congestion Shortfalls in 2021

Facility Group	Annual Shortfalls ($ Million)
Central to East	$71.9
Long Island Lines	$55.4
North to Central	$27.8
West Zone Lines	$17.0
All Other Facilities	$6.1

Central to East – These exhibited a dramatic increase in shortfalls from $9 million in 2020 to $72 million in 2021, accounting for roughly 40 percent of all shortfalls in 2021. The increase resulted primarily from more costly planned transmission outages, including:

- The Edic-New Scotland ("14" line) 345 kV circuit was out of service from March 22 to May 31 and from September 6 to November 14. This line outage alone typically reduces the interface transfer limit by nearly 800 MW.
- One of the Porter-Rotterdam ("30" & "31" lines) 230 kV circuits was out of service on almost every day during the nine-month period from March to November. This line outage alone typically reduces the interface transfer limit by nearly 200 MW.

These outages were taken primarily for the Central East Energy Connect project, which is expected to increase the transfer capability from Central to East New York by at least 350 MW.

Long Island – Long Island lines also exhibited an increase in shortfalls from $23 million in 2020 to $55 million in 2021, accounting for roughly 31 percent of all shortfalls in 2021. The lengthy forced outages of the tie lines between upstate and Long Island were the primary driver:

- The Sprainbrook-East Garden City ("Y49") 345 kV circuit was forced out in two separate periods, one from October 1, 2020 to April 16, 2021 and the other from August 6, 2021 to October 7, 2021, for a total of 179 days in 2021.
- The Dunwoodie-Shore Road ("Y50") 345 kV circuit was forced out from July 17 to September 20 for a total of 66 days in 2021.
- There were also 46 days in the summer when both the Y49 and Y50 were out of service, during which Long Island heavily relied on expensive oil-fired generation.

The two PAR-controlled lines between New York City and Long Island (i.e., the 901 and 903 lines) contributed $5 million of congestion surpluses, partly offsetting the total shortfalls on

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

Long Island. These consistently caused congestion surpluses because the assumed flows from Long Island to New York City across the two lines is typically 300 MW in the TCC auctions and 200 MW in the day-ahead market in 2021. Since these flows 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. This underscores that scheduling the 901 and 903 lines in an efficient manner would substantially reduce production costs.[114]

North to central New York lines – Day-ahead congestion shortfalls accruing on these lines nearly doubled to $28 million in 2021. The primary driver was the transmission outages taken throughout most of the year for the Moses-Adirondack Smart Path Reliability Project.

West Zone –Constraints in the West Zone exhibited shortfalls in 2021 that were comparable to 2020, driven primarily by different assumptions regarding Lake Erie Circulation and other modeling differences between the TCC auction and the day-ahead market.

The NYISO allocates most of the day-ahead congestion shortfalls that result from transmission outages to the specific responsible transmission owners.[115] In 2021, the NYISO allocated 69 percent of these shortfalls in this manner, up from 58 percent in 2020. Allocating congestion shortfalls to the responsible transmission owners provides incentives to minimize the overall costs of transmission outages.

Congestion shortfalls that are not allocated to individual transmission owners are currently allocated statewide. These shortfalls typically result from modeling inconsistencies between the TCC auction and day-ahead market that are not related to a transmission outage, including transmission outages in neighboring control areas, loop flows, and the status of generators, capacitors, and SVCs (which affect the Central-East interface).

Balancing Congestion Shortfalls

Balancing congestion shortfalls result from reductions in 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.[116] Table 10 shows total balancing congestion shortfalls by transmission facility group.[117]

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114 See Recommendation #2012-8.

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

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

117 Section III.G 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.

Balancing congestion shortfalls were small on most days in 2021 but were high on a small number of days when unexpected events occurred. For example, TSA events that reduce the transfer capability into Southeast New York occurred on 32 days and accounted for nearly $11 million of the shortfalls in 2021.

Unplanned and forced outages (including extensions beyond the planned period) were another key driver. For example, the Edic-New Scotland ("14" line) 345 kV line was forced out on February 10 to 12, leading to the accrual of $3.5 million of shortfalls on the Central-East interface on these days.

Table 10: Balancing Congestion Shortfalls in 2021 [118]

Facility Group	Annual Shortfalls ($ Million)
West Zone Lines	
Ramapo, A & JK PARs	**$1.2**
Other Factors	**$2.6**
North to Central	**$2.0**
Central to East	
Ramapo, A & JK PARs	**-$4.8**
Other Factors	**$7.8**
TSA Constraints	**$10.8**
Long Island Lines	
Pilgrim PAR	**$0.3**
Other Factors	**-$4.6**
External	**$2.9**
All Other Facilities	**$3.3**

Although average loop flows around Lake Erie were small in 2021, rapid changes in clockwise loop flows continued to be a key driver of balancing shortfalls in the West Zone. Operation of the NJ-NY PARs (i.e., Ramapo, A, & JK PARs) improved after NYISO worked with PJM to incorporate the West Zone 115 kV constraints in the M2M process beginning in November 2019. These PAR operations resulted in $3.6 million of net *surpluses* on the Central-East interface and West Zone constraints in 2021 versus $5 million of net *shortfalls* in 2019.

Long Island lines contributed roughly $4.5 million of net *surpluses* in 2021, compared to nearly $7 million of *shortfalls* in 2020. This improvement was driven by several factors. First, modeling improvements have reduced inconsistencies between forecasted day-ahead and real-time Pilgrim PAR flows, which accounted for 42 percent of Long Island shortfalls in 2020. Since the NYISO started to incorporate 69 kV constraints on Long Island in the day-ahead and real-time markets, day-ahead Pilgrim PAR scheduling has improved and virtually eliminated

118 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.

associated shortfalls.[119] Second, tight transmission limitations and generation scheduling patterns increased surpluses on Long Island. Over $6 million of net *surpluses* accrued in August and September during the period when both Y49 and Y50 lines were out of service that led to severe real-time intra-zonal congestion. High real-time self schedules (hours 0-9 in particular) often exceeded scheduled generation levels in the day-ahead market, leading to congestion surpluses on Long Island lines. These surpluses usually do not occure when at either the Y49 and Y50 lines are in service because the tie line flows can be reduced to offset high self schedules.

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 markets. This provides several benefits, including:

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

However, transmission constraints on the 115 kV and lower voltage networks in New York were resolved primarily through out-of-market actions until May 2018 when the NYISO started to incorporate certain 115 kV constraints in the market that had led to:

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

Table 11 shows the frequency of out of market actions to manage constraints on the low voltage network in six areas of New York. The table summarizes the number of days from 2019 to 2021 when OOM actions were used in each area.

The NYISO has greatly reduced the use of OOM actions in recent years to manage low-voltage transmission constraints by modeling most 115 kV constraints in the day-ahead and real-time

119 Pilgrim PAR flows have significant impact on both the 138 kV and the 69 kV constraints. Pilgrim PAR adjustments to manage the 138 kV constraints are often limited by its impact on the 69 kV network, and vice versa. Prior to April 2021, only the 138 kV constraints' interaction with the Pilgrim PAR were modeled in the market software.

markets starting in December 2018.[120] OOM actions used to be most frequent in the West Zone, occurring on 260 days in 2018, but falling to just 10 days in 2021. This has helped improve the efficiency of scheduling and pricing in Upstate New York.

Table 11: Constraints on the Low Voltage Network in New York[121]
Summary of OOM Days for Managing Constraints, 2019-2021

Area	# of Days with OOM Actions		
	2019	**2020**	**2021**
West Zone	50	13	10
Central Zone	18	6	9
North & MHK VL	53	26	48
Capital Zone	83	8	27
Central Hudson	34	5	4
Long Island	156	137	120

The Capital Zone also saw a notable improvement. In addition to incorporating 115 kV transmission constraints in the market models, transmission upgrades have also reduced transmission congestion. Previously, the Bethlehem units were frequently dispatched out-of-merit to manage nearby 115 kV constraints. This has been greatly reduced following transmission upgrades completed in mid-2019. However, OOM actions rose modestly in 2021 because transmission outages (mostly to facilitate the Central East Energy Connect Project) led to increased needs for managing congestion on several unmodeled 115 kV facilities.[122]

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

- North & Mohawk Valley – 48 days – More than half of these were to commit the Saranac generator out-of-market to maintain adequate reserves for the N-1-1 requirement in the North Country load pocket that is not modeled in the day-ahead and real-time markets. Modeling local reserve needs in the market would help attract investment to such areas.
- Long Island – 120 days – These are evaluated below in detail.

OOM actions to manage low-voltage network constraints are still frequent on Long Island. Table 12 evaluates the frequency of OOM actions (including the total number of hours and the total number of days with such actions) to manage 69 kV constraints and TVR constraints in the

120 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.

121 See Section III.D in the Appendix for more details on the use of various resource types in 2021.

122 One of these, the North Troy-Reynolds 115 kV line, was identified by the NYISO routine process and incorporated in the market in the second half of 2021.

four load pockets on Long Island in 2020 and 2021. The table also shows the average estimated LBMP in each pocket based on the marginal costs of resources used to manage these constraints.

Table 12: Constraints on the Low Voltage Network in Long Island
Frequency of Action and Price Impact, 2020-2021

Year	Long Island Load Pockets	69kV OOM		TVR OOM		Avg. LBMP	Est. LBMP w/ Modeling Local Constraints
		#Hours	#Days	#Hours	#Days		
2020	Valley Stream	1050	79			$29.15	$33.70
	Brentwood	312	54			$27.97	$28.54
	East of Northport	480	52			$30.68	$35.62
	East End	114	13	1115	95	$31.45	$48.13
2021	Valley Stream	535	70			$53.78	$55.10
	Brentwood	3	2			$55.45	$55.46
	East of Northport	158	28			$55.79	$57.43
	East End	99	18	669	65	$56.97	$69.12

Although still frequent, OOM actions fell substantially in 2021 for at least two reasons. First, two 69 kV constraints have been secured in the market since mid-April 2021.[123] This allowed resources that were frequently dispatched OOM to manage these constraints to be scheduled economically (on 129 days). The NYISO has an on-going process to evaluate and incorporate additional 69 kV constraints into the market models, which identified another two 69 kV constraints that will be modeling beginning with the April 2022 software deployment.[124] This should help further reduce the OOM needs on Long Island and improve scheduling and pricing efficiency. Second, lengthy outages of the 345 kV tie lines with upstate New York (the Y49 and Y50 lines) reduced the need for OOM actions, particularly in the summer months.

This improved pricing efficiency on Long Island and lowered BPCG uplift from $14 million in 2020 to $6.5 million in 2021. Continuing to set LBMPs on Long Island more efficiently to recognize the marginal cost of satisfying local transmission constraints would provide better signals for future investment.

The current process allows the NYISO to periodically evaluate and incorporate additional 69 kV constraints into the market model as needed. However, this does not address the TVR requirements on the East End of Long Island where OOM actions for this need are still frequent. Hence, we recommend NYISO model East End TVR needs (using surrogate constraints) in the

123 These were the Brentwood-Pilgrim 69 kV line and the Elwood-Pulaski 69 kV line.

124 The two 69 kV lines are the Deposit-Indian Head line and the West Hempstead-Malverne line.

market software.[125] We illustrate in the Section III.E in the Appendix one approach to develop surrogate constraints that could be used to satisfy TVR constraints within the market models.

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 2020/21 and Summer 2021 Capability Periods (i.e., November 2020 to October 2021). Table 13 summarizes TCC cost and profit for the evaluation period separately for inter-zonal and intra-zonal TCCs.[126]

- 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 2020 to October 2021 netted a total profit of $66 million. Overall, the net profitability for TCC holders in this period was 26 percent (as a weighted percentage of the original TCC prices), compared to *negative* 33 percent in the previous 12-month period.

Table 13: TCC Cost and Profit
Winter 2020/21 and Summer 2021 Capability Periods

	TCC Cost ($ Million)	TCC Profit ($ Million)	Profit as a Percent of Cost
Intra-Zonal TCC			
West Zone	$51	-$20	-38%
Capital Zone	$32	$10	31%
Long Island	$10	$20	188%
All Other	$9	-$5	-57%
Total	**$102**	**$5**	**5%**
Inter-Zonal TCC			
Other to West Zone	$39	-$26	-68%
Other to Central New York	$40	$23	58%
Other to Capital & Hud VL	$61	$53	87%
All Other	$10	$11	106%
Total	**$150**	**$60**	**40%**

125 See Recommendation #2021-3.

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

In this reporting period, TCC buyers netted an average profit of 40 percent on the inter-zonal transmission paths and an average profit of 5 percent on the intra-zonal paths. Higher natural gas prices and more costly transmission outages led to higher-than-expected congestion in most regions in 2021. As a result, TCC buyers netted a profit on most transmission paths.

TCC buyers netted the largest loss of $46 million on transmission paths sinking at the West Zone (from a $90 million purchase cost). This coincided with lower day-ahead congestion in the West Zone in 2021, which fell nearly 20 percent from 2020. Higher imports from PJM, lower imports from Ontario, and lower Niagara generation were the key drivers of lower congestion in the West Zone, which were not well anticipated by market participants.

Conversely, TCC buyers netted a profit of $20 million on transmission paths sinking on Long Island (from a $10 million purchase cost). This coincided with a 32 percent increase in day-ahead congestion on Long Island from 2020 to 2021, driven by: (a) unexpected lengthy transmission outages of the Y49 and Y50 tie lines between upstate and Long Island; and (b) modeling of two 69 kV constraints in the market software starting in April 2021.

Similarly, TCC buyers netted a sizable profit of $63 million on transmission paths sinking in the Capital Zone and the Hudson Valley Zone (from a $93 million purchase cost). This coincided with a 168 percent increase in day-ahead congestion from Central to East from 2020 to 2021, driven primarily by: (a) the retirement of the Indian Point Nuclear Plants; and (b) lengthy transmission outages that were taken to facilitate the Central East Energy Connect project and greatly reduced the Central to East transfer capability during much of the year.

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, such as congestion caused by lengthy unplanned outages, are often a key driver of TCC profitability. TCC auction results generally show that the level of congestion was increasingly recognized by the markets from the annual auction to the six-month to the monthly auction. This is expected since more accurate information is available about the state of the transmission system and market conditions.

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.

VII. CAPACITY MARKET PERFORMANCE

The capacity market is designed to ensure that sufficient capacity is available to satisfy 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 2021 in Section A;
- Principles for compensating resources efficiently in the capacity market in Section B;
- Inefficiencies in 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,
  - Capacity accreditation enhancements in Section E,
  - Efficient capacity compensation for transmission investments in Section F,
  - Enhancements to better reflect seasonal capacity value in Section H, and
- Potential improvements to the economic transmission planning process which include appropriate consideration of the capacity value of proposed projects (Section G).

A. Capacity Market Results in 2021

The Capacity Demand Curves determine how variations in the cleared supply of capacity affect clearing prices. Table 14 shows average spot auction prices for each locality for the 2021/22 Capability Year and year-over-year changes in key factors from the prior Capability Year.[127]

Table 14 shows that capacity prices rose significantly in all regions except in New York City, where they fell sharply. Generation retirements and changes to the Installed Reserve Margin ("IRM") and Locational Capacity Requirements ("LCRs") were key drivers of year-over-year capacity price trends.

[127] Results for 2021/22 capability year, which runs from May 2021 through April 2022, are displayed through February 2022.

Table 14: Capacity Spot Prices and Key Drivers by Capacity Zone[128]

2021/22 Capability Year

	NYCA	G-J Locality	NYC	LI
UCAP Margin (Summer)				
2021 Margin (% of Requirement)	4.9%	11.7%	13.8%	8.7%
Net Change from Previous Yr	-4.4%	-3.2%	9.8%	-4.1%
Average Spot Price (Full Year)				
2021/22 Price ($/kW-month)	$4.18	$4.18	$4.31	$6.87
Percent Change Yr-Yr	160%	160%	-69%	126%
Change in Demand				
Load Forecast (MW)	37	-284	-278	21
IRM/LCR	1.8%	-2.4%	-6.3%	-0.5%
ICAP Requirement (MW)	626	-624	-946	-4
Change in UCAP Supply (Summer)				
Generation & UDR (MW)	-1289	-916	64	-80
SCR (MW)	-159	-105	-76	-11
Import/Export Capacity (MW)	378			
Change in Demand Curves (Summer)				
ICAP Reference Price Change Yr-Yr	-27%	-25%	-9%	-2%
Net Change in Derating Factor Yr-Yr	0.5%	-0.6%	-0.8%	-2.0%
Zonal EFORd Change Yr-Yr	0.6%	-0.4%	-0.6%	-1.7%

Rest of State spot prices rose by roughly $2.50/kW-month (160 percent) to average $4.18/kW-month for the year. The following factors contributed to higher prices:

- Generator retirements, chiefly that of the Indian Point 3 nuclear unit in April 2021, reduced internal supply by nearly 1,300 MW.
- Unsold capacity was higher in the 2021/22 Capability Year, primarily in the summer months. From July through October, the amount of unsold capacity averaged 200 MW. Roughly 80 percent of the unsold capacity was from one portfolio in the NYCA region.[129]
- The IRM rose to 120.7 percent, up from 118.9 percent the prior year.
- However, these factors were partly offset by increased imports from external control areas and reduced exports to external control areas.

Prices in the G-J Locality were equal to those of the NYCA because the LCR for the G-J Locality was low (87.6 percent) relative to supply. Hence, the G-J Locality cleared on the NYCA demand curve.

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128 See Sections VI.D and VI.E in the Appendix for more details.

129 We discuss this situation in greater detail later in Section IX.C.3.

Overall, the ICAP requirement for NYC declined by 946 MW of which 29 percent was attributable to a reduced load forecast and 71 percent was due to the reduced LCR. This caused NYC to clear on the NYCA demand curve in most months at a price that was 70 percent lower than the prior year. The reduction of the New York City LCR is discussed further below.

Finally, in Long Island spot prices rose by $3.83/kW-month (126 percent). The ICAP requirement was relatively unchanged from 2020/21, but generation and UDR ICAP supply fell by 80 MW (summer value). Winter prices through February 2022 were significantly higher as a consequence of higher NYCA prices.

Discussion of New York City LCR in 2021

The following factors led to lower LCRs in New York City in the 2021/22 Capability Year:

- The transfer limit across the UPNY/CONED interface between zones G and H increased by 1,000 MW as a result of operational changes by Con Edison. This increased the amount of generation from other areas that can be delivered to Zone J.
- The IRM set by NYSRC increased from 118.9 percent in 2020/21 to 120.7 percent in 2021/22. With more capacity held upstate in the resource adequacy model, the LCR Optimizer finds that less capacity is needed in higher-cost downstate localities.[130]
- Net CONE values fell in 2021/22 in other areas relative to New York City, making New York City capacity less attractive to the LCR Optimizer.
- The Long Island LCR was set at its Transmission Security Limit floor of 102.9 percent. However, the IRM was set at a level that assumed a lower Zone K LCR.[131] This caused the LCR Optimizer to remove capacity from Zone J as it shifted more to Zone K.

Our more general concerns with the LCR-setting process are addressed in Section C.

B. Principles for Achieving Efficient Locational Pricing for Capacity

Capacity markets should be designed to provide efficient price signals that reflect the value of additional capacity in each locality. This will direct investment to the most valuable locations and reduce the overall capital investment necessary to satisfy the "one day in ten year" planning reliability standard. The current framework for determining capacity prices involves:

a. Estimating Net CONE and creating a demand curve for each existing locality,

b. Determining the 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 and its demand curve.

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130 See Sections B and C for a discussion of the LCR Optimizer.

131 NYSRC's IRM-setting process does not consider the zonal Transmission Security Limits that NYISO applies in the LCR Optimizer. See Section C.2.

In this subsection, we evaluate the efficiency of LCRs that the NYISO determined for the upcoming 2022/23 Capability Year. There are numerous combinations of LCRs that could satisfy NYISO's planning reliability criteria. The NYISO sets LCRs using the "LCR Optimizer" method, which is designed to minimize consumer payments while respecting (1) the 1-in-10 reliability standard, (2) the systemwide IRM, and (3) transmission security limits (TSLs) in each locality. Increasing the LCR in an area tends to reduce its marginal reliability value because each additional unit of capacity provides diminishing benefits.

In evaluating the performance of the capacity market, we define two values 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.[132]
- Cost of Reliability Improvement ("CRI") – the estimated 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 (Net CONE) from the latest demand curve reset study divided by 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.

Figure 20 and Figure 21 show the estimated MRI, Net CONE, and CRI for each locality and zone based on the 2022/23 Final LCR Case.[133] It is apparent from Figure 21 that the use of the Optimized LCRs Method does not result in equal CRI values across zones:

- The range between the minimum CRI-value location of Zone A (at \$0.8 million per 0.001 events) and the maximum CRI-value location of Zone J (at \$3.5 million per 0.001 events) is 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 K indicates that it would be efficient to place additional capacity there, suggesting that its LCR for the 2022/23 Capability Year (99.5 percent) is below the efficient level.

Figure 21 shows that the CRI values for some zones exhibit considerable differences from those of other zones within the same capacity pricing region. This is the result of transmission constraints within in capacity pricing areas that cause resources in some zones within the area to

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

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

be much more valuable for satisfying New York's reliability needs that resources in other zones. Ideally these zones would be separated and priced to reflect this difference in reliability value.

Figure 20: Marginal Reliability Impact (MRI) and Net CONE by Locality and Zone
2022/2023 Capabilty Year

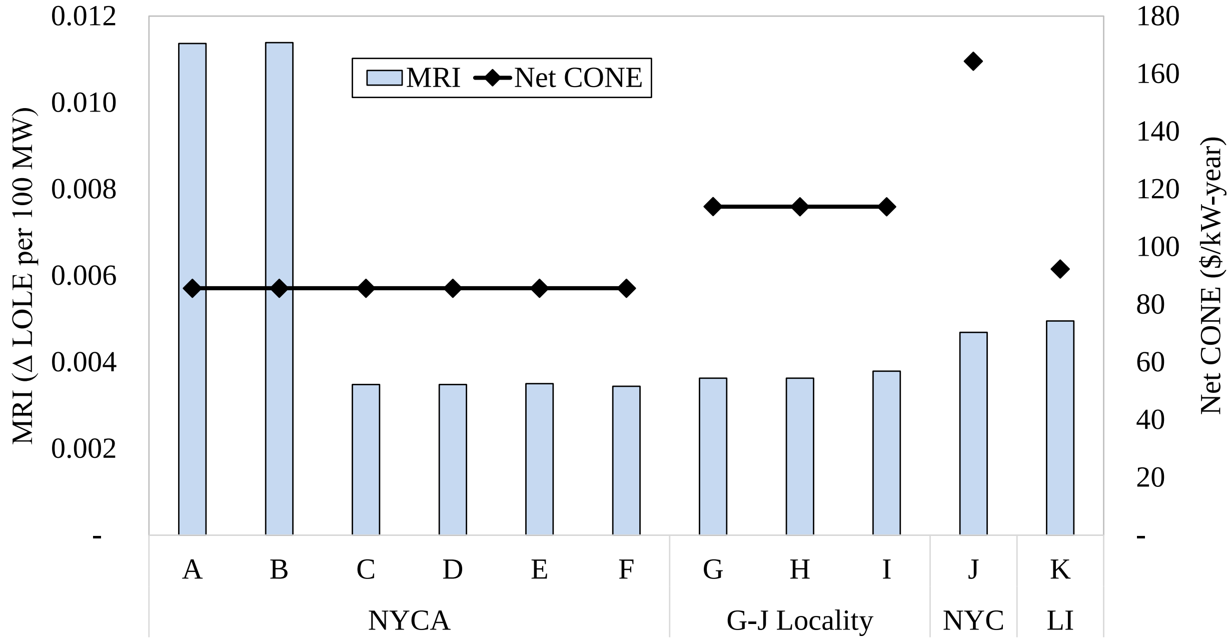
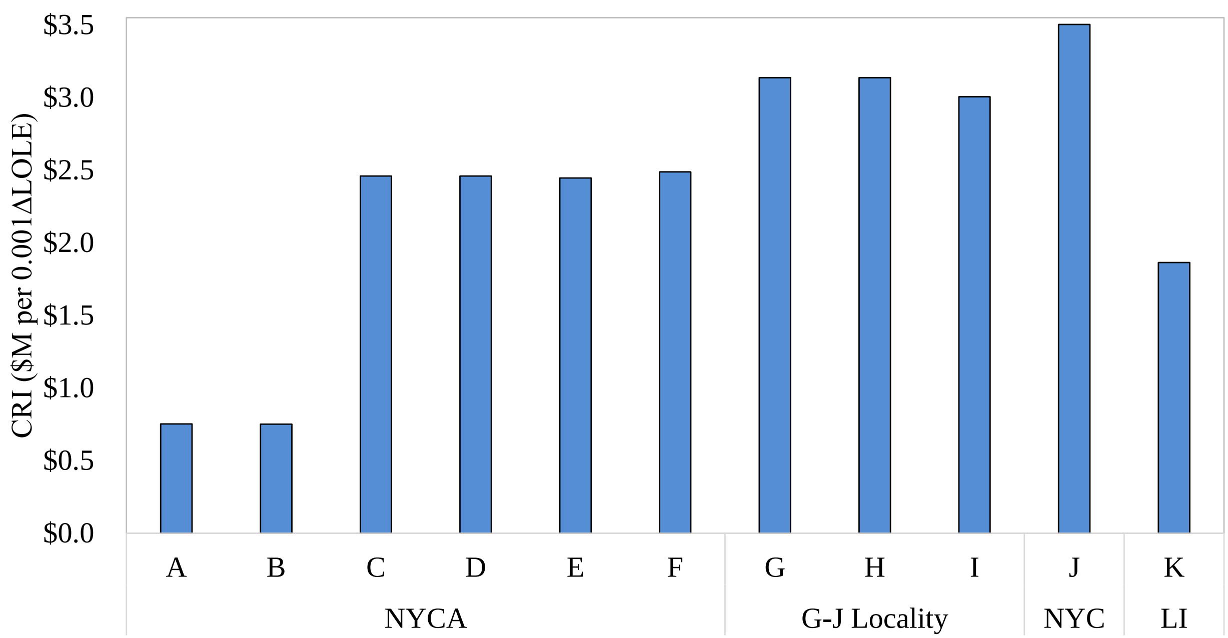


Figure 21: Cost of Reliability Improvement (CRI) by Locality
2022/2023 Capabilty Year at Level-of-Excess Conditions



The most notable intra-area differences in CRI in recent years have been:

- 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 before the 2020/2021 capability year. The emergence of the constraint is driven primarily by the retirement of the Kintigh coal unit in Zone A in 2020 and the modeling of energy limitations for certain resources in GE-MARS.[134]
- H&I Pocket – While Zones H and I will have CRIs similar to Zone G in the 2022/23 Capability Year, Zone G had a higher CRI than zones H and I in the previous capability year due to constraints on the UPNY/CONED interface between zones G and H. Depending on the degree of congestion on this interface, the CRI of Zone G could diverge more significantly in future years.[135]

Additional information on 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 supports 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. In this subsection, we identify several aspects of the current framework that can lead to inefficient capacity market outcomes.

1. Inadequate Locational Signals

Efficient locational capacity prices require capacity zones to be defined that accurately recognize the system's ability to utilize generation in different areas. As discussed above, we observe substantially different locational capacity values within a single capacity pricing area. 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 accurately reflect the locational value of resources within the NYISO system. Examples of current issues include:

- The lack of an A&B zone in the IRM-setting process has lead to a higher IRM because capacity cannot be specifically shifted into Zones A and B in the Tan45 procedure.[136]

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134 NYISO has recommended that improvements to modeling of energy limited resources (including large hydro resources) be included in the upcoming 2023/24 IRM study. It is likely that these improvements will put downward pressure on the IRM and reduce the disparity in MRI between zones A-B and C-F. See October 7, 2021 presentation to NYSRC "Sensitivity Using GE MARS in Modeling ELRs", available here.

135 Beginning in the 2021 capability year, Con Edison made operational changes to certain transmission facilities which increased the UPNY/CONED transfer limit, in response to the retirement of the Indian Point nuclear facility. Con Edison plans to revert these changes beginning in 2023 in order to resolve reliability needs in New York City that were identified in NYISO's 2020 Q3 Short Term Assessment of Reliability. See "Short-Term Reliability Process Report: 2023 Near-Term Reliability Need", available here.

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

- Deliverability of capacity from Staten Island to New York City is limited, but resources in Staten Island receive the NYC capacity price despite providing less value than other in-City units.[137]
- 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. This issue affected some projects in the interconnection process for Class Year 2019 as discussed below.

Example of Investment Disincentives Associated with Current Deliverability Rules

The results of the Class Year 2019 Long Island Additional System Deliverability Upgrade (SDU) Study completed in 2021 illustrate how the current zonal capacity market might discourage efficient new investment or lead to inefficient transmission upgrades. The study assessed SDUs that would be needed to make proposed new capacity deliverable and that would be assigned to the new entrants seeking capacity injection (CRIS) rights. Three developers were initially allocated $115.7 million in SDUs for offshore wind and storage projects on Long Island totaling 1,062 MW of installed capacity.

Table 15: Summary of CY19 Long Island Additional SDU Cost Allocations[138]

Queue #	Name	Technology	ICAP MW	Initial SDU Allocation ($ million)	Developer's Decision	Final SDU ($ million)
Q612	South Fork Wind Farm	Offshore Wind	96	11.6	Accept SDU	0.0
Q738	El Melville	Offshore Wind	816	67.5	Reject SDU, withdraw from study	N/A
Q746	Peconic River Energy Storage	Storage	150	36.6	Reject SDU, complete study without receiving CRIS	N/A

Altogether, the three projects would have had a combined qualified summer UCAP of approximately 440 MW based on the current capacity accreditation rules, so the average SDU cost would be $262 per kW of qualified UCAP. At recent 3-year average Zone K capacity prices of $4.0 per kW-month, it would take 25 years for these projects to recoup their initial SDU cost allocations from the capacity market (assuming cost of capital from the latest demand curve reset). However, it is possible that the payback period would be even longer because the qualified UCAP for these technologies is expected to fall as their penetration levels increase.

137 See our comments on NYISO's 2021-2030 Comprehensive Reliability Plan, available here.

138 See "Notice of Initial Decision Period to Class Year 2019 Long Island Additional SDU Study Projects" (March 11, 2021, available here) and "Notice of Class Year 2019 Long Island Additional SDU Study Completion" (April 27, 2021, available here).

Of these three projects, the 816 MW offshore wind facility rejected its cost allocation and did not complete the Class Year. The 150 MW energy storage facility rejected its cost allocation and completed the Class Year without receiving CRIS rights, so it will be unable to sell capacity.

Ultimately, it is inefficient to move forward with an SDU if the associated cost exceeds the additional reliability value of capacity that would result from the upgrade. In this case, it is unclear that the increased reliability value of capacity would have exceeded the upgrade costs.

It is likely that these projects would provide some capacity value even if they are not fully deliverable on a deterministic basis. Unfortunately, developers do not have the option to forgo costly upgrades and instead receive a discounted price based on the resource's sub-location within Zone K. This makes it difficult for new entrants to challenge incumbent generators affected by the same deliverability constraints, who can sell capacity and receive the Zone K price. Subsection D discusses our recommendation to implement a locational capacity market we refer to as "C-LMP", which would provide more efficient payments that do not discriminate against new entrants when deliverability is constrained within zones.

2. Problems with the LCR-Setting Process

The LCR Optimizer is designed to set LCRs satisfy reliability criteria at the minimum cost to consumers while respecting the IRM and transmission security limits (TSLs). However, the Optimizer produces results that are inefficient (i.e., that do not signal where investment is most valuable) and excessively volatile because of several design and implementation issues:

Flawed Objective Function – The LCR Optimizer uses a flawed objective function. It is designed to minimize consumer costs from the perspective of a single buyer with market power,[139] rather than minimizing investment costs (i.e., marginal production costs for capacity). By contrast, other NYISO markets are designed to minimize production costs because this is competitive and provides efficient incentives for producer behavior. The objective function also contributes to excessive volatility, as discussed below.

Sensitivity to Net CONE – LCRs are strongly influenced by Net CONE values because the LCR Optimizer sites more capacity in regions with lower costs. This process is inherently vulnerable to errors in Net CONE estimates, which can lead to an inefficient allocation of capacity across zones. Setting LCRs using Net CONE also increases volatility because updates to Net CONE values can cause LCRs to change even when underlying reliability values stay the same.

Misalignment with IRM Process – LCR values are strongly affected by the IRM, which acts as a constraint in the LCR Optimizer that limits the range of possible LCR outcomes. However, the

139 By minimizing overall consumers costs, the NYISO procures capacity acting as a monopsonist. Thus, the LCR Optimizer may shift purchases inefficiently from one area to another because of the resulting impacts on prices.

IRM itself embeds estimated LCRs determined using a different method from the Optimizer.[140] As a result, changes to the IRM can cause volatility in the LCRs. For example, the IRM does not consider the TSLs used in the LCR Optimizer, which can result in large discrepancies between the LCRs embedded in the IRM and the LCRs that the LCR Optimizer produces.

Misalignment with Demand Curves – 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, which is known as the "Level of Excess".

Figure 22 and Figure 23 illustrate how the current design of the LCR Optimizer contributes to volatility and inefficient outcomes. Both figures compare the marginal cost of capacity for the 2022/23 capability year based on two formulations:

- *Investment cost minimization* – This uses the Net CONE curves to represent marginal investment cost.[141] These are shown in the top panel of each figure, which are monotonic upward-sloping marginal cost curves.
- *LCR Optimizer formulation* – The marginal cost function at each location is derived assuming the NYISO minimizes overall consumer costs.[142] In the bottom panel of each figure, these non-monotonic marginal cost curves are shown to be discontinuous with irregular downward steps because the marginal consumer cost is strongly affected by slight changes in the steepness of Net CONE curve steps.[143] For example, Figure 22 shows that if the LCR in Zone J rises from 80.6 to 86.6 percent, the Net CONE rises just 4.4 percent, while the corresponding marginal consumer cost curve falls by 24.0 percent.

For each locality in each formulation, Figure 22 shows the marginal cost of capacity per kW-year, while Figure 23 shows the cost of reliability improvement (CRI) curve. Each CRI curve equals the marginal cost curve from Figure 22 divided by the marginal relibability impact of capacity in the locality.[144] [145] Thus, the CRI curve is the marginal cost of capacity per unit of

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140 This process is known as the "Tan 45" procedure. A description of this process can be found in the NYISO presentation to NYSRC on June 3, 2020 "Unified Methodology & IRM Anchoring Method", available here.

141 This is because the first-order conditions of the investment cost minimizing optimization problem include the Net CONE functions in each location.

142 The marginal cost function at each location is derived from the first order conditions of the consumer cost minimization problem.

143 Monotonicity is an important because it allows a solver to find the unique cost-minimizing solution more quickly, while non-monotonic cost functions make the problem non-convex and more difficult to solve.

144 We simulated MRI curves based on a set of MARS-derived LOLE values for various combinations of LCRs. Because all possible combinations of LCRs cannot be feasibly tested, the MRI curves are approximate.

145 This chart assumes a fixed IRM at the 2022/23 level of 119.6 percent. With a constant IRM, the CRI in locality X is equal to: (marginal cost of adding capacity in locality X – marginal cost of adding capacity in NYCA) / (MRI of locality X – MRI of NYCA).

LOLE improvement. The red diamonds indicate simulated LCRs determined using the LCR Optimizer cost function.[146]

Figure 22: Optimizer Cost Curves vs. Net CONE Curves
2022/2023 Capabilty Year

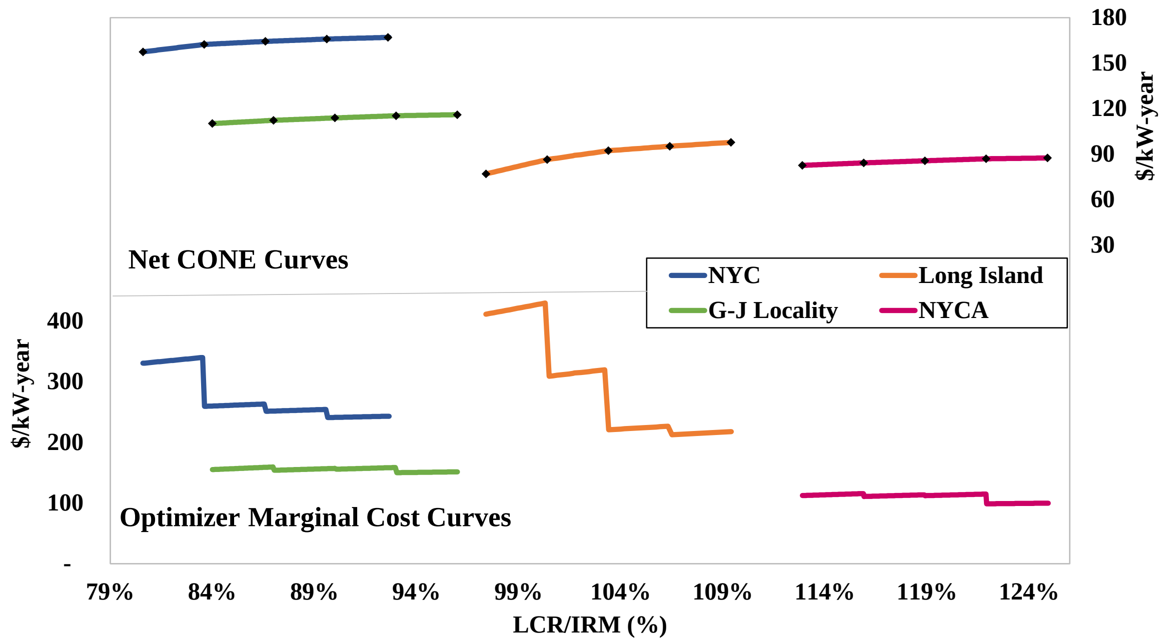
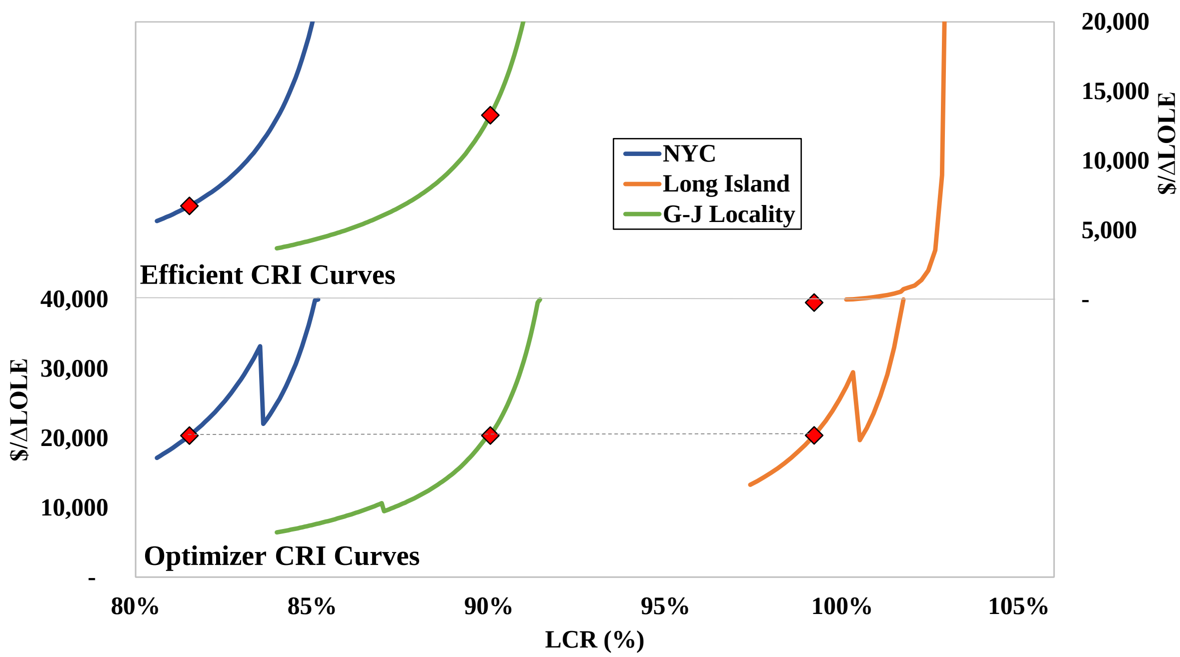


Figure 23: Optimizer CRI Curves vs. Efficient CRI Curves
2022/2023 Capabilty Year



146 The simulated LCRs indicated by the red diamonds in Figure 23 differ slightly from the actual 2022/23 LCRs because MRI was simulated using a limited number of MARS data points.

In Figure 23, the bottom panel illustrates how the LCR Optimizer seeks a solution that equalizes CRI values across localities while satisfying the LOLE criterion, IRM, and TSLs. However, because the Optimizer calculates the marginal cost of capacity based on consumer costs, it relies on CRI curves that are not monotonic and may produce similar values for multiple different LCRs. Ultimately, this raises the following concerns:

- Because the Optimizer computes each locality's CRI in a way that produces the same value at multiple different LCRs, changes in model assumptions may lead to unpredictable and volatile changes in LCRs.
- The Optimizer does not produce efficient LCRs. In this example, the Zone K LCR is inefficiently low and the G-J Locality LCR is inefficiently high.

By contrast, the top panel shows how calculating the marginal cost of capacity based on investment costs produces uniformly upward sloping CRI curves, which allow the optimal solution to be found more quickly and reliably.

3. Some Types of Capacity are Over- or Under-Compensated

Generator Capacity Accreditation – NYISO recently proposed to annually calculate resources' capacity credit based on marginal reliability contribution for all resource types. To implement this approach, it is important to ensure that all resource types are modeled accurately in the resource adequacy model and the capacity market. These accreditation issues are discussed in detail in Subsection E.

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.[147] The NYISO also does not adequately consider this value in its economic and public policy transmission processes.

The remaining sections discuss our recommended approaches to improving the capacity market and its consideration in the planning process:

- 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.

147 The NYISO has an opportunity to address this with its Internal Controllable Lines project.

- Section G discusses how to quantify capacity benefits of transmission projects and make other improvements in the planning processes.
- Section H proposes changes to better reflect seasonal variations in the value of capacity.

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 marginal reliability value of capacity in each locality. It may not be possible for the NYISO to address the concerns discussed in Subsection C in a piecemeal fashion. Hence, we propose an alternative approach to setting locational capacity prices that would address all of the issues with one comprehensive approach. Our approach, which we call "C-LMP", would:

- Reduce the costs of satisfying resource adequacy needs – In a previous study, we estimated a reduction in annual capacity payments by consumers of $516 million when the system is at the "Level Of Excess" as described later in this section,[148]
- Provide efficient incentives for investment under a wide range of conditions,
- Improve the adaptability of the capacity market to future changes in the resource mix and in the transmission network topology, and
- Reduce the complexity of administering the capacity market as the system evolves.

Additionally, our proposed C-LMP framework would address issues that we identified in Subsection C related to excessive volatility caused by the LCR Optimizer and efficient compensation of imports. The remainder of this section discusses C-LMP.

Overview of C-LMP

We recommend the NYISO adopt our proposed C-LMP Framework, which would involve: [149]

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

Under C-LMP, it would not be necessary to define LCRs or locality-specific demand curves based on estimated Net CONE values. Instead, capacity prices would be determined as the

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148 The "Level of Excess" is the amount of capacity surplus that the capacity market is designed to obtain. This study is detailed in 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. See ICAPWG presentations dated Feb. 6, Feb. 19, and Mar. 10, 2020.

149 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.

product of (1) the MRI at each location, and (2) a systemwide optimal CRI parameter designed to incentivize new entry when reliability is near the 1-in-10 criterion.[150] This approach aligns the price at each location with the marginal reliability contribution of capacity at that location.

Features of the C-LMP Approach

Under C-LMP, spot market prices reflect the MRI of each location under as-found conditions at the time of the monthly auction. The MRI values would be calculated for: (a) each location in NYISO's planning model for each type of generation and load, (b) internal transmission interfaces, (c) external interfaces, and (d) UDRs. The MRI value for each type of generation would be determined in accordance with marginal capacity accreditation principles recently filed by the NYISO and approved by FERC.[151]

The C-LMP method involves estimating one key administrative parameter every four years (concurrent with the Demand Curve reset study) – the optimal level of CRI. This parameter reflects the estimated net capital investment cost of an incremental improvement in LOLE. Because optimal CRI is a single systemwide parameter, variations in spot prices across locations are driven only by differences in their MRIs.

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.

The C-LMP approach would be less administratively burdensome than the current capacity market process 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).
- The NYISO could use the same modeling techniques for locational capacity pricing that it has proposed for determining capacity accreditation for each type of resource.

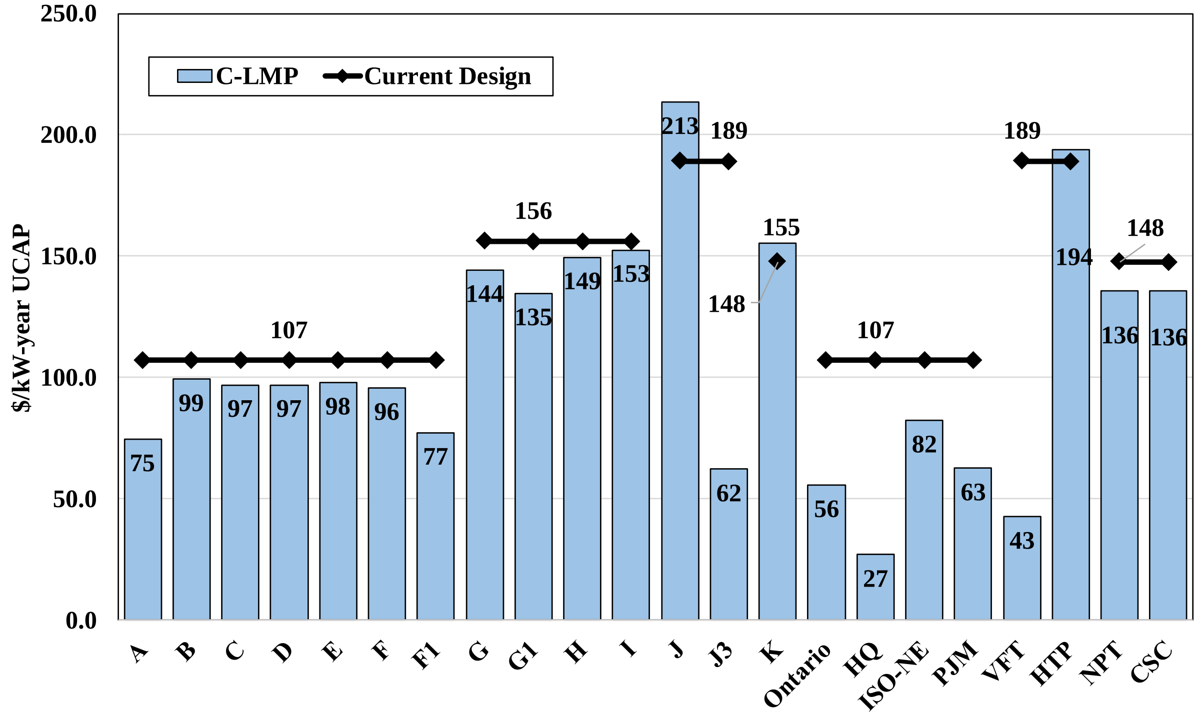
150 See Recommendation #2013-1c in Section XI.

151 See May 10, 2022 Order in Docket No. ER22-772-001.

Analysis of C-LMP

Figure 24 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.[152] 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 24: Capacity Prices at the Level of Excess for C-LMP vs. Existing Framework
Based on 2019 Final LCR MARS Case



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 for the 2019/20 capability year. In particular:

- Resources in the Staten Island (J3) 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.

152 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.

- 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.

We have also estimated that consumer payments would fall by approximately $516 million per year at "level-of-excess" conditions under the C-LMP framework.[153] The primary reasons for this reduction is that C-LMP would procure capacity more optimally based on their costs and reliability value, reduce payments to generators at locations that are currently overvalued, and reduce payments to imports that have lower reliability value than internal capacity. In addition, we assume that payments to Transmission Owners for the capacity value of transmission under C-LMP would be used to offset embedded costs of transmission infrastructure that are borne by ratepayers, thus lowering the overall net consumer payments.[154,155]

E. Improving the Capacity Accreditation of Individual Resources

Capacity accreditation refers to the fraction of a resource's installed capacity that can be sold in the capacity market. It is intended to reflect the likelihood that the resource will be available when needed for reliability. This subsection discusses methods to establish capacity credit in NYISO and proposed enhancements.

Status of NYISO Capacity Accreditation

Transactions in the capacity market are denominated in UCAP terms, so the applies methods for converting the installed capacity (ICAP) value of each resource to UCAP. These conversion methods rely on simple heuristics that do not accurately reflect the marginal reliability impact of each resource type. For example, the UCAP of an intermittent resource is calculated based on its average output in a range of hours each day, which is not necessarily when supply is tightest. As a result, the UCAP ratings of some existing resources are overvalued.

In early 2022, the NYISO filed tariff revisions with FERC to revise how it establishes resources' capacity credit ratings. NYISO proposes to establish a Capacity Accreditation Factor for each resource class reflecting its marginal contribution to reliability (e.g., its expected availability during hours when load shedding is most likely). The Capacity Accreditation Factors will be updated annually and will be calculated for each capacity market region. The new Capacity Accreditation Factors will take effect in the 2024/25 capability year.

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153 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.

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

155 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.

These changes are a major improvement to the capacity market. Aligning resources' compensation with their marginal contribution to reliability is necessary to encourage efficient investment in a diverse resource mix. A description of marginal capacity accreditation and its benefits compared to alternative approaches can be found in Appendix VI.I.

Enhancements to Capacity Value Modeling

The marginal accreditation framework should be supplemented by improvements to modeling techniques. NYISO's methodology for calculating Capacity Accreditation Factors relies on its resource adequacy model, GE MARS, which is used to establish the IRM each year. MARS is an Monte Carlo model that simulates hourly load and resource availability under a variety of conditions. Hence, the representation of each resource type in MARS will affect its capacity credit. While NYISO's MARS model is a sophisticated tool, it has limitations in modeling the following resource types:

- *Gas-Only Generators* – NYISO has 8.8 GW of gas-fired generation without dual fuel capability, of which only 2.5 GW were supported by firm fuel contracts in Winter 2021-22.[156] During extreme cold conditions, the total supply of fuel to these units is limited, so they are not able to operate simultaneously. MARS does not model shared fuel supplies and treats outages of each of these units as independent of each other. If risks to shared fuel supply are not reflected in capacity payments, the market will overvalue these resources. NYISO already has a limited capacity margin for unusually cold winter conditions, large quantities of oil-fired and dual-fuel generation are planned to retire over the next three years, and winter demand growth is expected to grow more rapidly in the future, making it important for the market to reflect this need.[157]
- *Load-Correlated Resources* – MARS models hourly load patterns independent of resource availability. In reality, a common factor may affect both load and availability of some resources. For example, weather is a key driver of both solar output and load. Similarly, despite significant growth in behind-the-meter solar, MARS uses load shapes that largely do not reflect its impact. This may cause resources that are correlated with or complementary to behind-the-meter solar to be valued inaccurately. Aligning the modeling of the resource mix and load profiles to reflect common drivers would produce more accurate capacity value estimates.
- *Energy Storage* – Modeling realistic dispatch of energy limited resources (ELRs) is challenging because it must balance considerations of optimal discharge and limited foresight. In the past two IRM studies, the NYISO modeled ELRs using a simple fixed output shape regardless of system conditions. The NYISO has recommended an

156 See December 10, 2021 NYISO presentation to NYSRC Executive Committee "2021-22 Winter Assessment & Preparedness", available here.

157 In the most recent winter season, NYISO expected to have a capacity margin of just 525 MW under extreme (99/1) weather conditions, after accounting for loss of gas-fired generation without firm fuel supply. See December 10, 2021 NYISO presentation to NYSRC Executive Committee "2021-22 Winter Assessment & Preparedness", available here.

alternative approach in which ELRs are dispatched to avoid load shedding prior to emergency actions (such as deployment of SCRs and reserves) but may only discharge in a predetermined set of hours.[158] This approach is an improvement, but it should be refined so that: (a) a portion of storage capacity is withheld until reserve deployment steps, representing a more optimal and realistic usage, and (b) remaining 'peak shaving' storage is targeted to periods when shortages are most likely, reflecting strategic behavior with imperfect foresight.[159] It may also be necessary to examine whether the sequencing of emergency actions in MARS such as external assistance results in unrealistic timing of ELR dispatch.

- *Inflexible Resources* – Inflexible units such as steam turbines with long startup lead times provide less reliability value than more flexible units, because they may be unable to respond in time when needed. However, MARS treats these units as if they are always committed and available if not in an outage state. Hence, capacity value of these resources is likely to be overvalued as net load uncertainty increases due to rising deployment of intermittent resources.

Availability of Fossil Generators

Figure 25 shows the average availability of fossil generators during 30-minute reserve shortages in the period 2017 through 2021. Cumulative availability of steam turbine, combined cycle and gas turbine capacity are shown as duration curves.[160] When calculating average performance, each interval was weighted based on the magnitude of 30-minute reserve shortage in that interval. Availability was calculated as the sum of energy and reserves provided by the unit divided by its ICAP. A unit may be unavailable if it is experiencing an outage, is not able to generate at full capacity, or cannot start or ramp up in time to respond to the shortage.

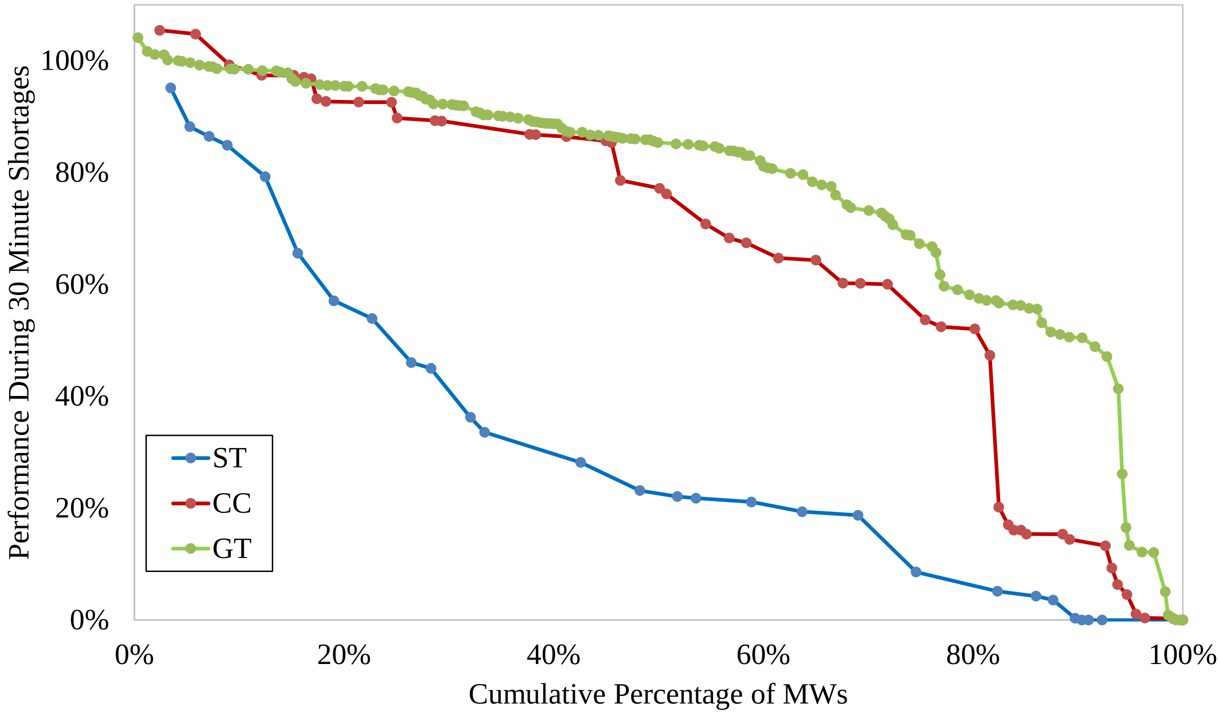
Figure 25 illustrates key facts about the performance of fossil generators. First, current methods to determine UCAP have overstated the contribution during tight hours of many units. Second, there are large differences in availability during reserve shortages based on technology, with inflexible steam turbines performing the worst and flexible gas turbines performing the best. Third, there are also large differences in performance within each technology group, suggesting that characteristics of the individual unit – such as its startup time, ramp rate, how well it is maintained and how often it is committed in the energy market – play a key role in its reliability.

158 See October 7, 2021 presentation to NYSRC "Sensitivity Using GE MARS in Modeling ELRs", available here

159 For an example of such an approach, see our comments on NYISO's 2019 storage capacity value study, available here.

160 For each point, the percentage on the X-axis of total capacity of that resource type had average performance during shortage events greater than or equal to the percentage on the Y-axis

Figure 25: Average Availability During 30-Minute Reserve Shortages
2017-2021



It is important to note that historic availability during reserve shortages does not necessarily dictate a unit's expected availability during future load-shedding conditions. For example, consider an inflexible unit that is often unavailable during brief and shallow real-time reserve shortages that occur periodically when there is a large capacity surplus, because the unit had not been committed economically. The same unit may be highly reliable in a future period when the capacity surplus is small and the unit is committed more often during high load periods.

Recommended Improvements

We recommend that that NYISO consider improvements to more accurately evaluate marginal reliability contributions of the following resource types: (a) gas-only generators with limited/no backup fuel, (b) energy limited resources, (c) resources whose availability is correlated with load, and (d) inflexible generators. (see Recommendation #2021-4) [161]

It may not be possible to derive marginal capacity values for all resource types by performing an ELCC or MRI calculation in MARS. For example, inflexible resources may be difficult to model this way because MARS is not designed to consider unit commitment separately from dispatch. Additionally, availability may depend on unit-specific factors (such as how often the

161 Recommendation #2021-4 in Section XI also includes refinements to the capacity qualification rules for conventional generators with emergency operating ranges, ambient water temperature limitations, and EFORd values that tend to overstate their availability under peak conditions.

unit is committed economically) that are not best modeled as class-based features. Hence, it may be preferable to develop a heuristic that uses thermal resources' actual availability during tight hours to adjuste their capacity credit or payments. Such an approach should consider the appropriate weighting to be assigned to each hour, the relationship between historic and expected availability, and how the approach will interact with MARS.

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.[162] The Appendix of this report analyzes how FCTRs might affect a transmission investment decision.[163]

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 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 (as discussed in Subsection C.1).

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

163 See Appendix Section VI.G for additional details.

G. Reforms to the Economic Transmission Planning Process

Integrating large amounts of renewable generation in the coming years will drive the need for transmission investments. It is important that NYISO's economic transmission planning process accurately evaluates project benefits so that the most cost-effective projects move forward.

The Economic Planning Process

The NYISO has an Economic Planning Process consisting of two main phases. The first phase assesses projected congestion patterns over the next two decades and the potential value of expanding transmission capability. The second phase evaluates specific projects proposed by developers and 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.[164] However, since being established in 2008, no transmission has been built through this process.

In 2021, FERC approved changes to the Economic Planning Process proposed by NYISO. The changes improved the initial study phase to make it more flexible and informative (the System & Resource Outlook "SRO").[165] NYISO has also adopted improvements in modeling techniques for the SRO, such as using capacity expansion tools to model scenarios reflecting policy-driven changes in the resource mix. However, the project evaluation phase remains overly restrictive and unlikely to select economic projects for approval.

The NYISO also has a Public Policy Transmission Planning Process, in which it solicits solutions to policy-driven needs identified by the NYPSC. NYISO has evaluated solutions for two Public Policy Transmission Needs ("PPTN"): the Western New York PPTN and the AC Transmission PPTN.[166] 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 2021, the NYISO was ordered by the NYPSC to consider solutions to a PPTN for transmission to deliver offshore wind energy interconnected to Long Island, and this process is currently underway.[167]

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

165 See FERC Docket ER21-1074.

166 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.

167 See NYPSC Case 20-E-0497.

New York State is establishing a process to plan investments in lower-voltage local transmission and distribution that are needed to accommodate clean energy goals.[168] As the grid evolves, congestion on bulk transmission paths may emerge that is not addressed by this process or evaluated under the lengthy and cumbersome PPTN process. The NYISO economic planning process should complement these efforts by providing a mechanism to address congestion on bulk transmission facilities. However, the project evaluation stage is burdened by overly restrictive evaluation metrics, model inputs, and procedural rules, which are discussed below.

Improvements to Planning Processes

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 have also identified a number of areas for potential improvement in that process.[169] Key areas for improvement to the economic planning process include the following:

- Capacity Benefits – The Economic Planning Process significantly undervalues some projects because its benefit-cost ratio does not include capacity market benefits.[170] Transmission projects can provide value by reducing the amount of generation capacity needed to meet local planning requirements.[171] Hence, we recommend including capacity market benefits in the benefit-cost ratio 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 balanced criteria to identify resources likely to enter in the near-to-mid term (e.g. 5-7 year horizon) that can reasonably be included when evaluating projects.
- Voting Requirement – Before an economic project is funded, the project must garner approval from 80 percent of the beneficiaries. While this is intended to ensure that only clearly economic projects move forward, the 80 percent threshold is unreasonably high and can enable a small group of participants to block an economic investment.

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168 Local transmission generally refers to facilities that serve local load or operate at less than 200 kV. See NYPSC Case 20-E-0197.

169 See March 22, 2021 comments of Potomac Economics in NYPSC Case 20-E-0197 (available here), January 22, 2019 comments of Potomac Economics in NYPSC Case 18-E-0623 (available here), and February 2019 report *NYISO MMU Evaluation of the Proposed AC Public Policy Transmission Projects (*available here*).*

170 Under the rules adopted in 2021, NYISO will calculate capacity cost benefits of relieving congested facilities in the SRO (Phase 1) and may evaluate these benefits for specific projects in the Economic Transmission Project Evaluation (Phase 2), but these calculations are for informational purposes and are not included in the benefit-cost ratio used to determine if a project is eligible for cost recovery.

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

- Size Threshold – Only projects exceeding $25 million are eligible for cost recovery. This could exclude smaller projects (such as upgrades to existing lines or substations) whose benefits exceed their costs. This project size threshold should be reduced or eliminated.

In summary, 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.[172]

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 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. [173]

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).[174] 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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172 See Recommendation #2015-7 in Section XI.

173 See Recommendation #2019-4 in Section XI.

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

VIII. 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 resources in one area to compete to serve consumers who would otherwise be limited to higher-cost resources in another area; 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.[175] Hence, NYISO's total import capability is large relative to its load, making it important to schedule the interfaces efficiently.

This section provides a summary of interchange patterns between New York and neighboring control areas in recent years (subsection A) and a discussion of loop flow patterns that cause congestion and price volatility in western New York (subsection B). Subsection C evaluates the performance of Coordinated Transaction Scheduling with ISO New England and PJM.

A. Interchange between New York and Adjacent Areas

Table 16 summarizes the net scheduled imports from neighboring control areas from 2016 through 2021 during peak (i.e., 6 am to 10 pm, Monday through Friday) hours.[176]

Table 16: Average Net Imports from Neighboring Areas

Peak Hours, 2016 – 2021

Year	Quebec	Ontario	PJM	New England	CSC	Neptune	1385	VFT	HTP	Total
2016	1,408	778	382	-664	205	590	39	129	11	2,878
2017	1,332	863	344	-416	234	563	64	156	33	3,173
2018	1,372	733	442	-564	164	561	30	201	253	3,192
2019	1,327	686	492	-810	155	610	37	224	179	2,900
2020	1,258	750	367	-965	89	509	52	179	164	2,403
2021	1,317	585	699	-586	228	313	90	256	332	3,236

175 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. The A line is a PAR-controlled line that interconnects NYC to New Jersey, which 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 Section V.F and Appendix Section V.C.

176 Figure A-67 to Figure A-70 in the Appendix provide additional details.

Total net imports from neighboring areas averaged 3.2 GW during peak hours in 2021, up noticeably by 35 percent from 2020 and 7 percent higher than the average from 2016 to 2019. The increase seen in 2021 relative to the recent years was driven largely by changes in the resource mix of internal generation, congestion patterns, regional gas price spreads.

Controllable Interfaces

Net imports from neighboring areas satisfied nearly 27 percent of Long Island's demand in 2021, comparable to the 2020 level but lower than the levels normally seen from 2016 to 2019. Reduced imports to Long Island over the last two years were driven primarily by transmission outages, including:

- Cross Sound Cable imports fell due to lengthy outages from August to December 2020.
- The Neptune line was partially available from September 2020 through the end of 2021, and it was completely out of service for the month of January 2021.

The lower net imports across the Cross Sound Cable and the Neptune Cable contributed to higher congestion and LBMPs on Long Island.[177] However, the 1385 line exhibited the highest net imports in the past six years because of higher LBMPs on Long Island.

New York City saw an increase in imports across controllable lines, particularly the HTP line, in 2021 from prior years. Together, the HTP and Linden VFT lines contributed nearly 590 MW of energy in peak hours in 2021, up from 310 MW from 2016 to 2020. Imports over these lines were highest in the winter months when regional gas price spreads rose, making PJM generation more economic relative to NYISO generation. In 2021, flows to eastern New York across the Central-East Interface were reduced because of lengthy transmission outages and the Indian Point retirements increased energy prices in Eastern New York, attracting more imports from PJM. This was especially true during the summer months.

Primary Interfaces

Average net imports from neighboring areas across the four primary interfaces rose 43 percent from 1,410 MW in 2020 to 2,016 MW in 2021 in peak hours. This increase was driven mostly by higher net imports from PJM and lower exports to New England, although these trends were partly offset by lower imports from Ontario.

The interface with Quebec accounted for most of the net imports across all the primary interfaces, accounting for 65 percent in 2021. Average net imports from Quebec consistently ranged between 1,250 MW and 1,400 MW in each year from 2016 to 2021 with very high

[177] See Appendix Section III.C for discussion in more details.

utilization of the lines. Variations in Quebec imports are largely caused by transmission outages on the interface.

Net imports across the primary interfaces with PJM, New England, and Ontario exhibited more variations over the last six years. Net interchanges with PJM and New England generally tracked variations in gas price spreads between these regions. For example, New York normally imports from PJM and 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).

Transmission outages and generator retirements also affected interchange with PJM and New England in 2021 as the average net exports to New England fell 380 MW from 2020 to 2021, while the average net imports from PJM rose by 330 MW, contributing a net increase of 710 MW of net imports. Higher congestion across the Central-East interface resulting from planned transmission outages and the Indian Point retirements have made it more costly to export to New England but more economic to import from PJM. Consequently, the primary PJM interface exhibited the highest average import levels since 2016.

Net imports from Ontario fell noticeably from prior years, averaging 585 MW in 2021, which was the lowest average since 2016. Lengthy major transmission outages reduced the transfer capability from West to East, reducing incentives to import to Western New York. In addition, the transmission work related to the Beck Project at the border often reduced the interface transfer capability, contributing to lower imports from Ontario as well.

B. Unscheduled Power Flows around Lake Erie

Unscheduled power flows (i.e., loop flows) around Lake Erie have significant effects on power flows in the surrounding control areas. Loop flows that move in a clockwise direction generally exacerbate west-to-east congestion in New York, leading to increased congestion costs. Although average clockwise circulation has fallen notably since the IESO-Michigan PARs began operating in April 2012, large fluctuations in loop flows are still common.[178] There was a strong correlation between the severity of West Zone congestion and the magnitude and volatility of loop flows in 2021, although average clockwise loop flows were small.[179]

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.

178 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.

179 See Section III.F in the Appendix for more details.

- In November 2019, the NYISO and PJM started to incorporate 115 kV constraints into the M2M JOA process.
- In April 2020, 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), which provides a more accurate representation of the effects of interchange with Ontario on loop flows.

In addition, to further reduce the market and operational impact of volatile loop flows on transmission constraints, the NYISO implemented:

- 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.
- A more conservative assumption in RTC regarding loop flows.[180] 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 initializes.[181]

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 Appendix Section V.E; and (c) the day-ahead and balancing congestion shortfall uplift in Section VI.A.

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. In this subsection, we discuss several factors that have affected CTS performance at the PJM and ISO New England interfaces, particularly the effects of transaction fees and short-term price forecasting. We also provide a detailed analysis of factors that contribute to poor short-term price forecasting.

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180 The NYISO revised the zero-MW lower bound on clockwise loop flows assumed in the RTC initialization to a 100-MW lower bound in late November 2019.

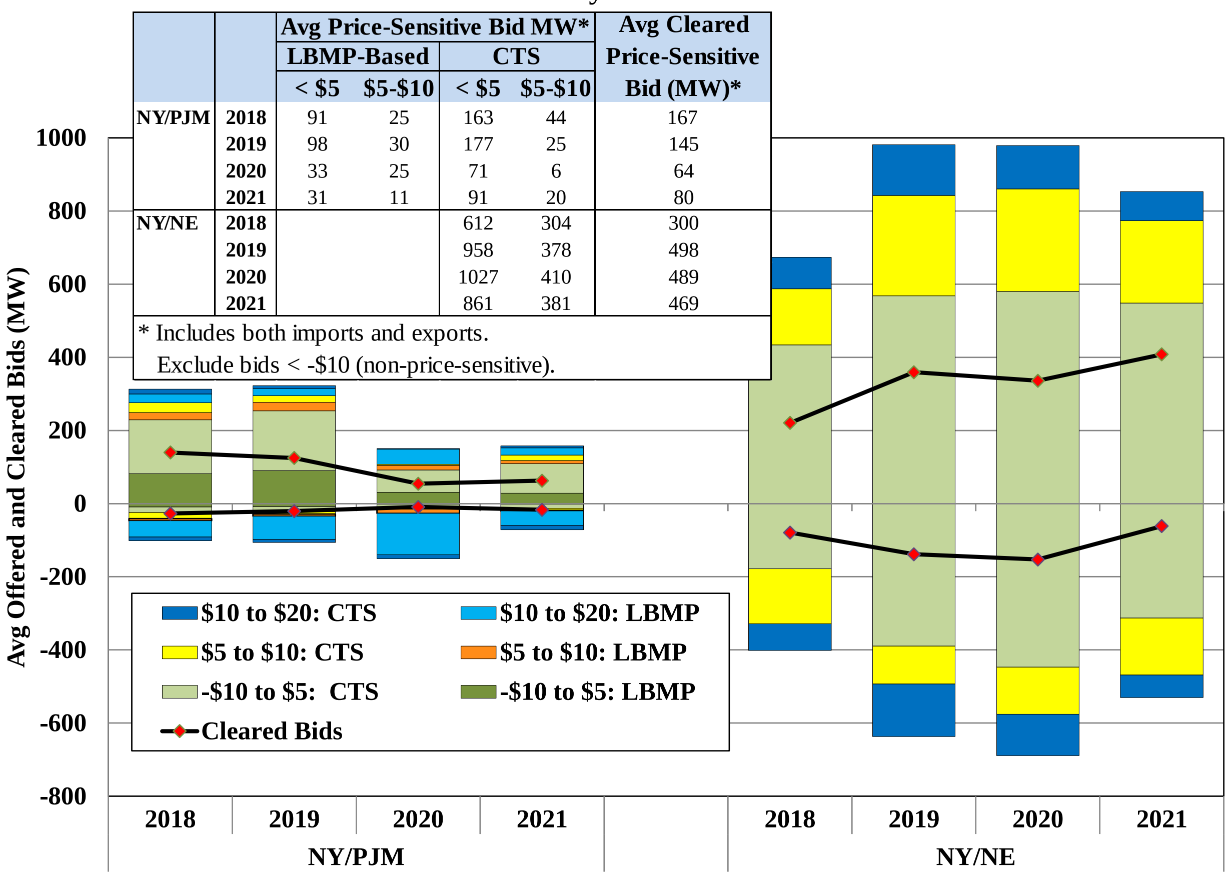
181 See Section V.E in the Appendix of our 2019 State of the Market Report for more details.

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 26 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 2021.[182] 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.[183]

Figure 26: Average CTS Transaction Bids and Offers

PJM and NE Primary Interfaces – 2018-2021



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 2021. An average of 865 MW (including

182 Figure A-72 in the Appendix shows the same information by month for 2021.

183 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.

both imports and exports) was offered between -$10 and $5 per MWh at the New England interface over this four-year period, substantially higher than the 189 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 was nearly four-times the average amount cleared at the PJM interface over this four-year period.

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.[184] The amount of real-time exports scheduled price-sensitively at the PJM border averaged just 18 MW over the four-year period from 2018 to 2021, much lower than the average amount of real-time imports scheduled price-sensitively (roughly 95 MW). This was primarily because fees were significantly higher on transactions scheduled from NYISO to PJM than the opposite direction. These charges are a significant economic barrier to achieving the potential benefits from the CTS process at the PJM border.

Figure 27 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 2021.[185] The gross profitability of scheduled real-time transactions (including both imports and exports) averaged roughly $0.45 per MWh over the five-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.

At the PJM border, the average gross profitability was significantly 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.

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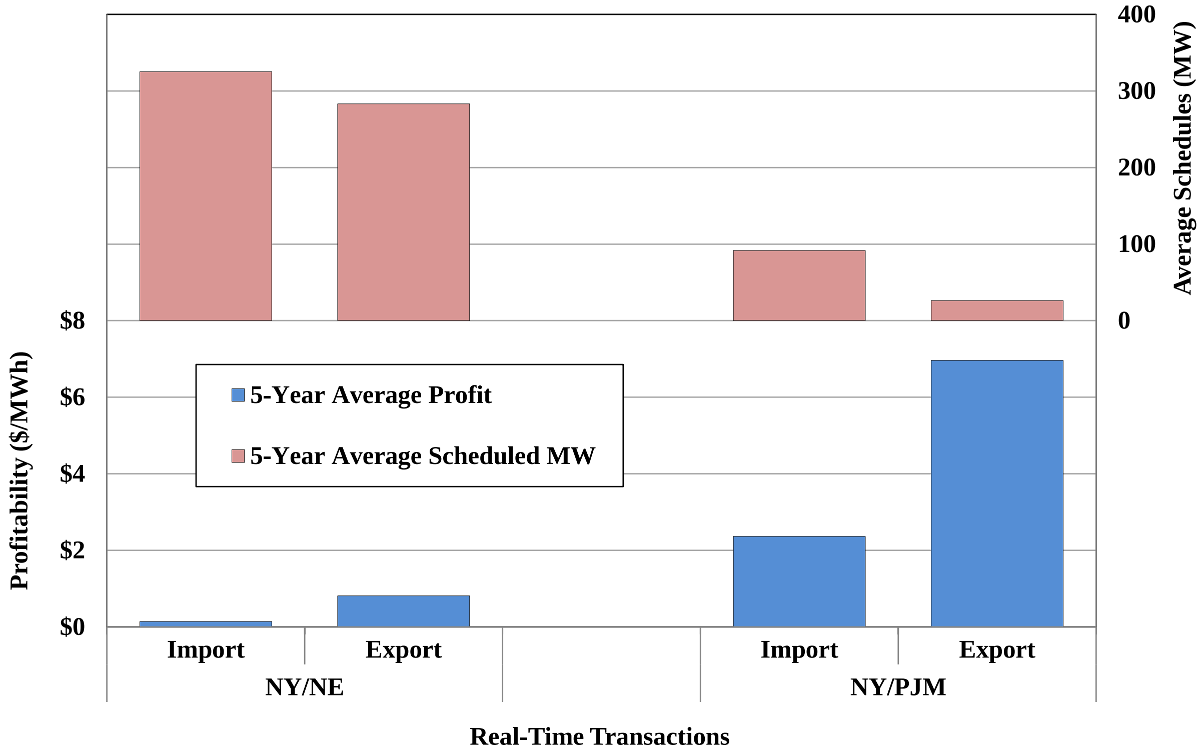
184 Although PJM increased its Transmission Service Charge substantially to firm imports/exports to $6.34/MWh in 2020, it kept the non-firm transactions at a low level of $0.67/MWh. This change to firm transactions has little impact on CTS transactions. In addition, PJM charges "real-time deviations" (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.

185 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).

Figure 27: Gross Profitability and Quantity of Scheduled Real-Time External Transactions
PJM and NE Primary Interfaces, 2017-2021



We recommend eliminating (or at least reducing) these charges at the interfaces with PJM for several reasons.[186] 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 $0.8 million in export fees from real-time exports to PJM in 2021, while PJM collected $1.7 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.

186 See Recommendation #2015-9.

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.[187]

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 2021, this adjustment (from our estimated hourly schedule) occurred in 83 percent of intervals at the New England interface, compared to 48 percent at the PJM interface. However, inaccurate price forecasts reduced the savings that were actually realized. We estimated that in 2021,[188]

- $9 million of savings were realized at the New England interface; and
- $1 million were realized at the PJM interface.

The actual production cost savings were higher at both interfaces in 2021 than in 2020, reflecting more frequent interchange adjustments and higher differences in energy prices between the markets partly because of higher regional gas price spreads in 2021. Nonetheless, production cost savings at the PJM border was still much lower than at the New England border. This resulted partly from relatively large price forecast errors. At the two CTS interfaces, the price forecasts produced by PJM were far less accurate than those produced by NYISO and ISO New England in recent years.

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 2021. 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

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

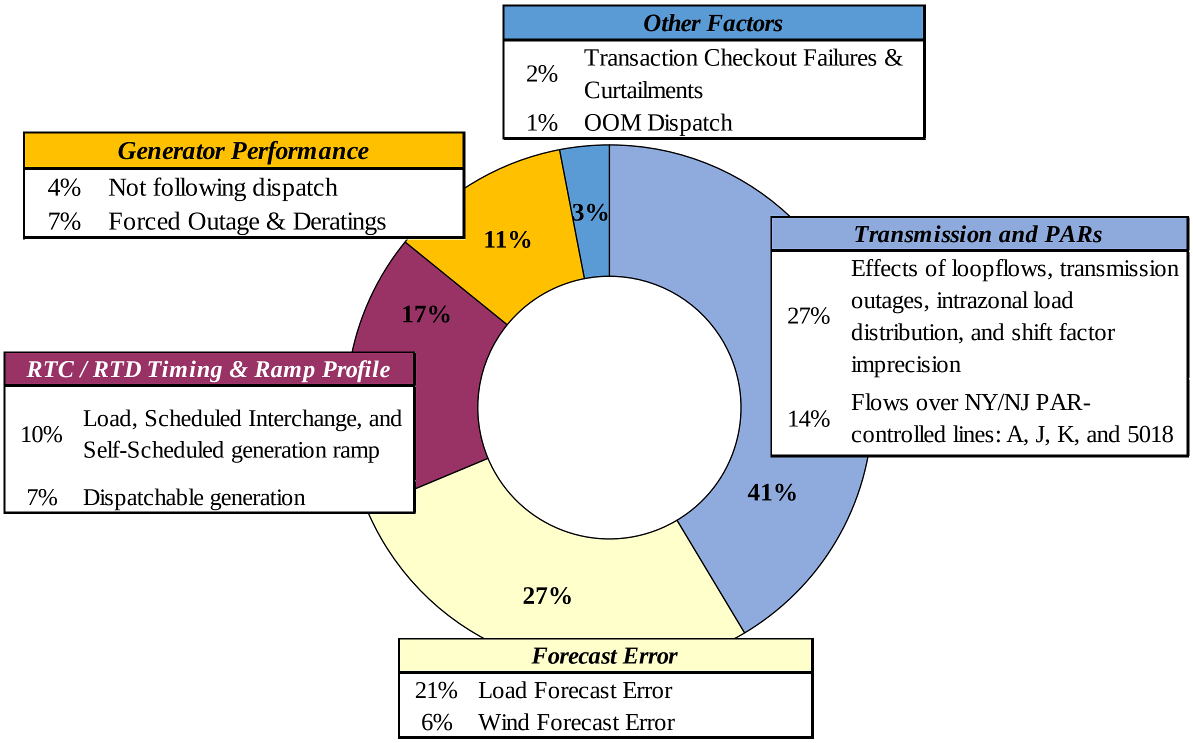
188 Our evaluation tends to under-estimate the production cost savings, because the hourly schedules that we estimate would have occurred without CTS reflect some of the efficiencies that result from CTS.

to forecast errors over time.[189] We expect that this evaluation will be useful as the NYISO and stakeholders prioritize different projects to improve market performance.

Figure 28 summarizes the RTC/RTD divergence metric results for "detrimental" factors (i.e., factors that cause or contribute to differences between RTC and RTD) in 2021.[190] Similar to our findings from previous reports, our evaluation identified three primary groups of factors that contributed most to RTC price forecast errors in 2021.[191]

Figure 28: Detrimental Factors Causing Divergence Between RTC and RTD

2021



First, transmission network modeling issues were the most significant category, accounting for 41 percent of the divergence between RTC and RTD in 2021, comparable to the 43 percent in 2020. In this category, key drivers include:

- Variations in the transfer capability available to NYISO-scheduled resources that result primarily from: (a) transmission outages; (b) changes in loop flows around Lake Erie and from New England; (c) inaccuracies in the calculation of shift factors of NYISO units, which are caused by the assumption that flows over PAR-controlled lines are not affected by generation re-dispatch; and (d) variations in the distribution of load within a zone.

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

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

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

- 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.

Second, errors in load forecasting and wind forecasting were another large contributor to price differences between RTC and RTD, accounting for 27 percent of the overall divergence between RTC and RTD in 2021.[192] The contribution of the load forecast error rose from prior years, reflecting generally higher load forecast errors in 2021 likely as a continued consequence of the Covid-19 pandemic and increased penetration of behind-the-meter solar.

Third, the next largest category, which accounted for 17 percent of the divergence between RTC and RTD prices in 2021, was related to inconsistencies in assumptions related to the timing of the RTC and RTD evaluations. This includes inconsistent ramp profiles assumed for external interchange, load, self-scheduled generators, and dispatchable generators. For example, RTC assumes external transactions ramp to their schedule by the quarter-hour (i.e., at :00, :15, :30, and :45), while RTD assumes that external transactions start to ramp five minutes before the interval and reach their schedule five minutes after the interval (five minutes later than RTC).[193]

We have recommended improving the consistency between the ramp assumptions used in RTC and RTD. A list of recommended changes is listed in Section XI.[194] Previously, we also recommended considering enhancing modeling of loop flows and flows over PAR-controlled lines to more accurately reflect the effects of expected variations.[195] Although we still believe that implementing this recommendation would provide some value in the form of more efficient scheduling, we do not recommend pursuing it at this time because the level of effort and cost involved would be large relative to the expected benefit compared to other recommendations.

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

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192 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.

193 Figure A-78 in the Appendix illustrates the ramp profiles that are assumed by RTC and RTD for external transactions.

194 See Recommendation #2012-13.

195 See Recommendation #2014-9 in our 2020 SOM report.

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.

IX. 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 2021 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 evaluates the use of the market power mitigation measures in the capacity market for New York City and the G-J Locality and capacity market outcomes in areas with no mitigation measures.

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 import-constrained areas.

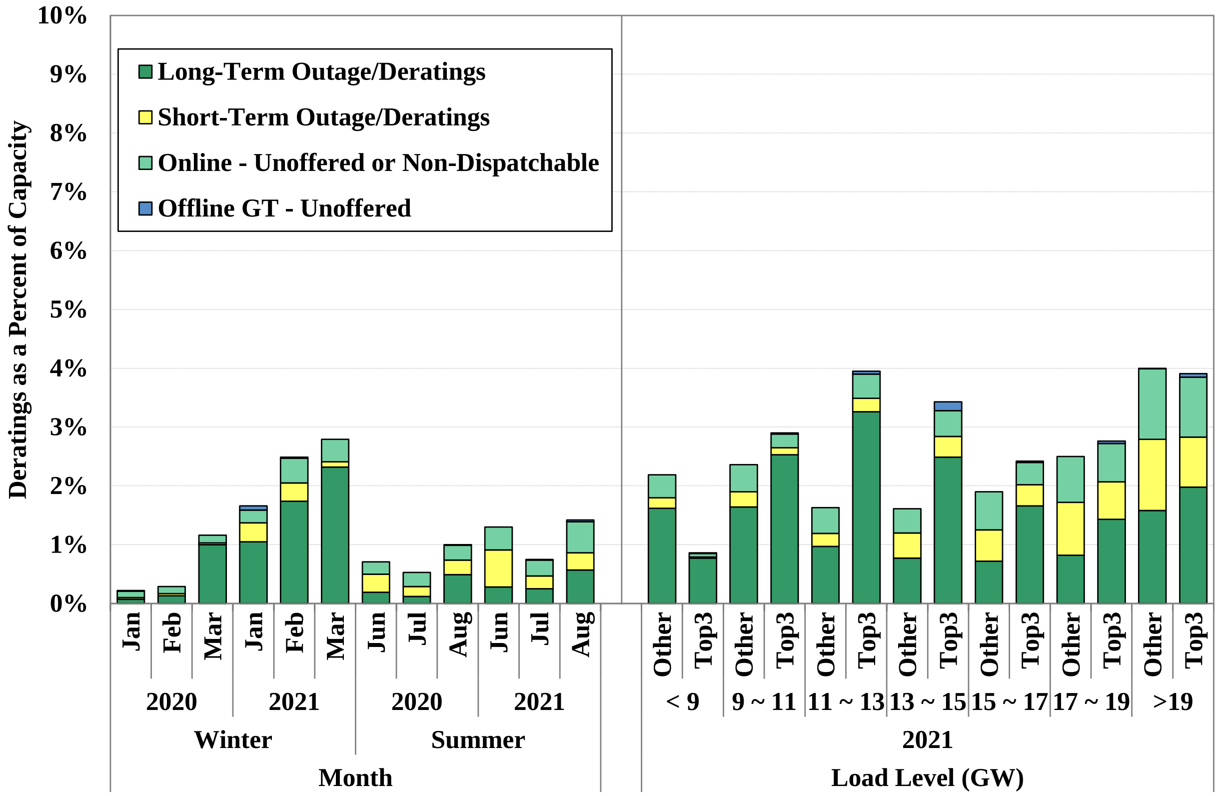
In this competitive assessment, we evaluate potential physical withholding by analyzing economic capacity that is not offered in real-time, either with or without a logged derating or outage. We evaluate potential economic withholding by estimating an "output gap" which is the amount of generation that 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.[196] Figure 29 and Figure 30 show the two potential withholding measures relative to season, load level, and the supplier's portfolio size.[197] Generator deratings

196 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.

197 Both evaluations exclude capacity from hydro and other renewable generators. They also exclude nuclear units during maintenance outages, which cannot be scheduled when the generator is not economic. Sections II.A and II.B in the Appendix show detailed analyses of potential physical and economic withholding.

and outages are shown according to whether they are short-term (i.e., seven days or fewer) or long-term.

Figure 29: Unoffered Economic Capacity in Eastern New York
2020 – 2021



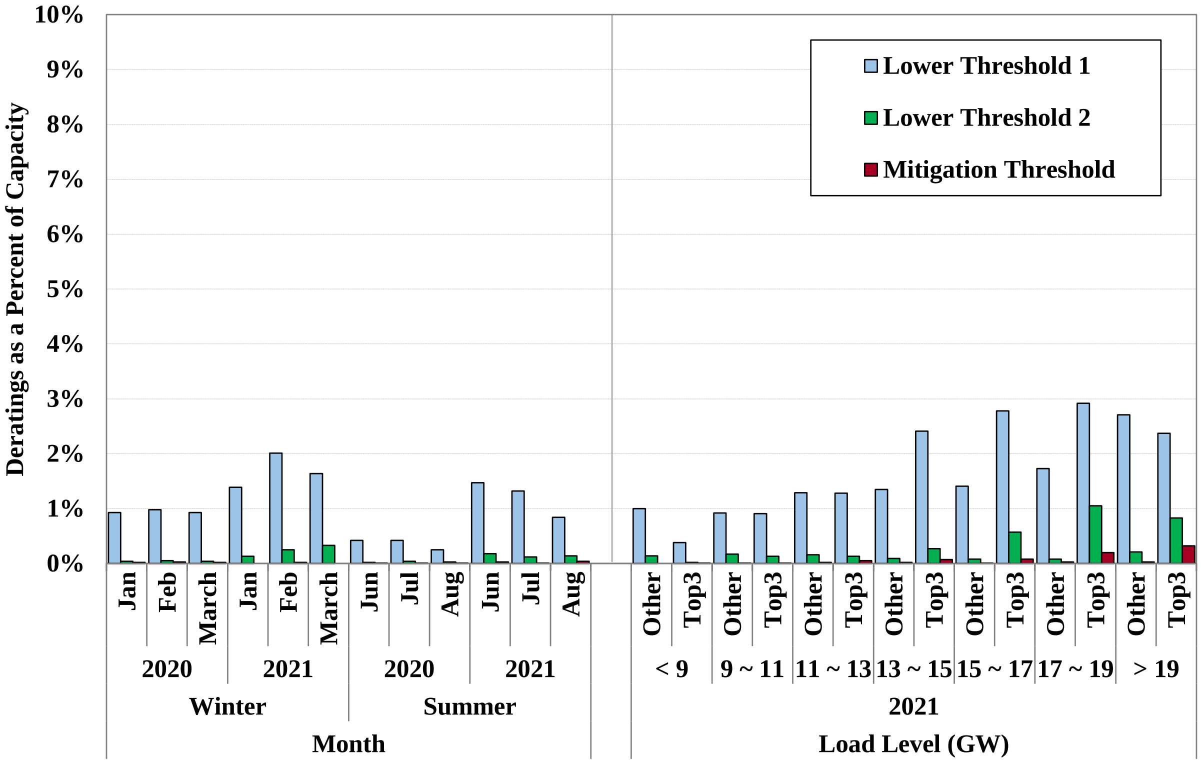
Overall levels of unoffered economic capacity remained low in 2021, consistent with prior years, but did increase from 2020 because of changes in transmission and generation outage scheduling patterns. Most unoffered economic capacity in 2021 occurred in the shoulder months, i.e., from March to May and September to November, consistent with years before 2020. However, it was different from 2020 when much of the spring maintenance work was deferred by generators during the height of the Covid-19 pandemic. Hence, unoffered economic capacity rose in 2021 due to more seasonal outages of many baseload generators, especially in the Capital Zone when coincident transmission outages contributed to higher levels of congestion than typical.

The figure shows that the top suppliers in Eastern New York exhibited higher levels of long-term outages during moderate load conditions (11 to 15 GW). This was primarily associated with multi-month-long seasonal outages that overlapped with some periods of moderate to load conditions.

The amount of unoffered economic capacity increased with load levels as roughly 4 percent of economic supply was unavailable during the highest load hours (greater than 19 GW). Both long-term and short-term outages increased during this period as low capacity factor units ran more frequently during peak load conditions. During these hours, approximately 1 percent (i.e., a quarter of the four percent of total unoffered economic capacity) of this was due to unoffered or non-dispatchable capacity from online resources. Notable reasons for online resources not offering their upper output ranges included:

- *Inflexibility of duct-firing capacity* – Some combined cycle units offer inflexibly in real-time to manage physical operating constraints on the duct burner portion of the output range. The current NYISO market models treat the duct burners as incremental energy capable of responding to AGC and eligible for 10-minute reserve products; however, duct-firing capacity is generally not flexible enough to provide either of these services.
- *Ambient temperature conditions* – Capacity ratings for temperature-dependent resources change daily based on unit-specific output factor curves that adjust for ambient air temperatures. However, this does not account for factors such as humidity and pressure. Furthermore, some units are affected during the summer by ambient water temperatures.[198]

Figure 30: Output Gap in Eastern New York
2020 – 2021



The amount of output gap in Eastern New York remained very low in 2021, averaging 0.02 percent of total capacity at the statewide mitigation threshold and 1.2 percent at the lowest threshold evaluated (i.e., 25 percent above the Reference Level).

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198 See the 2021-Q3 State of the Market report (slide 23) for more on the impact of unoffered capacity from steam and nuclear units during the summer period due to non-air-related ambient conditions.

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. Winter weather conditions were relatively mild in 2021, which contributed to low levels of output gap during those months. The summer did not witness significant amounts of output gap either.

Most of the output gap in 2021 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.[199] To limit the potential for excessive mitigation in areas with strict mitigation measures (i.e., New York City), most NYC generators have cost-based Reference Levels.

It is generally a positive indicator that the unoffered economic capacity and the output gap were comparable for top suppliers and other suppliers during high load conditions when the market is most vulnerable to the exercise of market power. Overall, the patterns of unoffered capacity and output gap were consistent with competitive expectations and did not raise significant concerns regarding potential physical or economic withholding under most conditions.

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.[200]

- 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.

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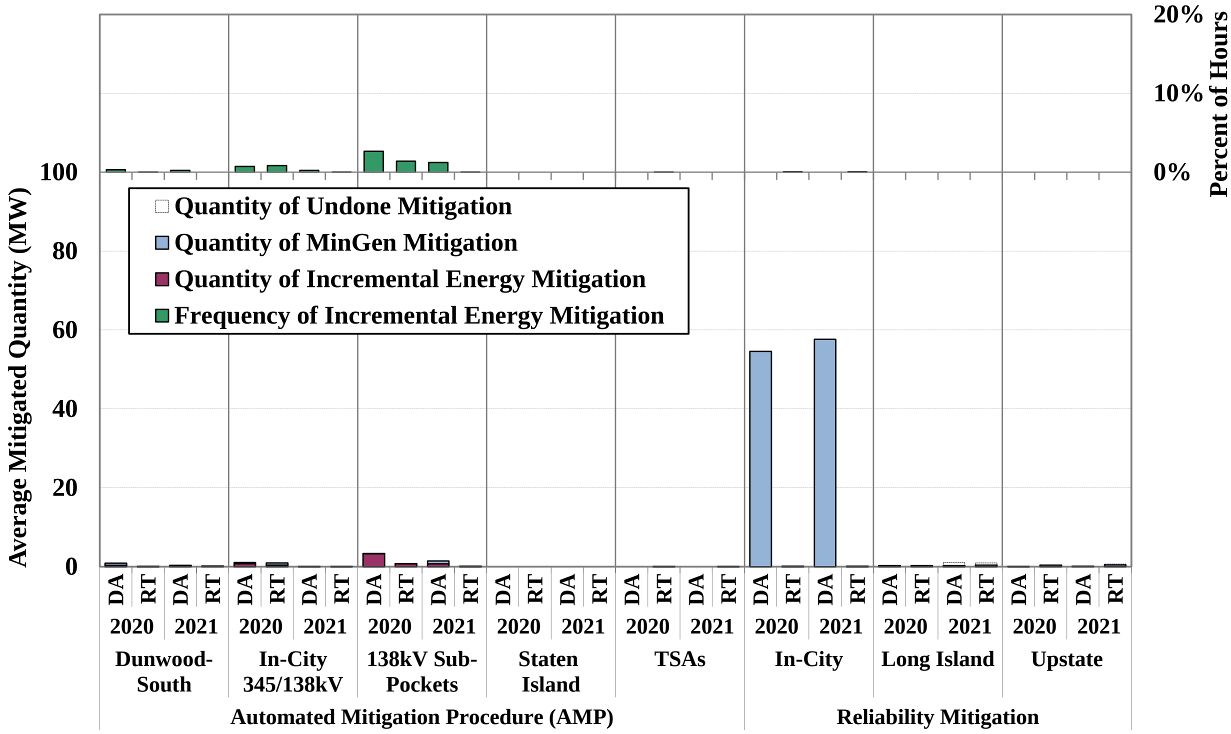
199 Attachment H of the NYISO Market Services Tariff outlines the three type of reference levels that a generator may have. The first type that will be calculated based on the availability of data is a bid-based reference level. This value is calculated as the average of accepted economic bids during 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.

200 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.

- 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 31 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.

Figure 31: Summary of Day-Ahead and Real-Time Mitigation
2020 - 2021



This figure shows that most mitigation occurs in the day-ahead market when most supply is scheduled. Reliability mitigation accounted for 97 percent of all mitigation in 2021, 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 increase from 2020 to 2021 due to higher loads driving greater reliability commitments.[201] The reliability mitigation is critical for ensuring that the market performs competitively because units that are needed for local reliability usually have market power.

AMP mitigation accounted for just 3 percent of total mitigation and was down from 2020 levels in all areas of New York City. AMP mitigation only applies when there is an active transmission constraint. The relatively low levels of congestion in New York City load pockets during 20201

201 See Section V.G for more details on the reduced reliability commitments in New York City.

along with an increase in load pocket thresholds 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 has increased in frequency as the Indian Point units have retired and eastern New York has become 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.

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.[202]

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.[203]

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

[202] See NYISO MST, Sections 23.4.5.2 to 23.4.5.6.

[203] 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.

levels. Parts 1 and 2 of this subsection discuss the application of capacity market mitigation measures in 2021. Part 3 of this subsection discusses certain market outcomes outside the Mitigated Capacity Zones during 2021.

1. 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.

2. 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") and Class Year 2019 Additional System Deliverability Upgrades ("CY19 ASDU") evaluations. Table 17 and Table 18 describe each CY19 and CY19 ASDU Examined Facility, respectively, and the final status of its BSM evaluations.

Six projects in Zone J and seven projects in Zone G, including 37.5 MW of energy storage resources, 173 MW (ICAP) of solar PV resources, and 816 MW (ICAP) of offshore wind 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 of the CY19 and CY19 ASDU Examined Facility, and we posted reports documenting the results of our review.[204, 205] Overall, we found that the NYISO's BSM determinations in CY19 and CY19 ASDU were made in accordance with the requirements of the Tariff and based on reasonable assumptions.[206]

The NYISO has made major changes to the BSM rules that will effectively eliminate mitigation for state-sponsored policy resources, starting in May 2022 during CY21.[207]

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

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

206 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 our report for all recommendations.

207 See NYISO's January 5, 2022 filing in Docket ER22-772. These were approved in the Order dated May 10, 2022 in Docket ER22-772-001.

Table 17: Results of CY19 BSM Evaluations

Examined Facility	Zone	Summer CRIS 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	

Table 18: Results of CY19 ASDU BSM Evaluations

Examined Facility	Summer CRIS MW	Unit Type	Status
CH Interconnection	1000	HVDC	Initial determinations only
Liberty Generating Alternative	1172	CC	
Ravenswood Energy Storage 1	129	ESR	
Ravenswood Energy Storage 2	129	ESR	
EI Sunset Park	816	Offshore Wind	Exempt under REE

3. Capacity Market Results Outside the Mitigated Capacity Zones

This part of the subsection discusses notable capacity market outcomes in the Rest of State region (Zones A to F) where capacity prices rose in 2021 significantly from recent years after a large increase in the NYCA capacity requirement and generator retirements at the Indian Point plant.[208] Following this increase in price levels, a substantial amount of in-service capacity went

208 See Section VII.A for additional details.

unsold for several months. This was noteworthy because, for most generators, once they incur the costs needed to be in service, there is little or no additional cost to be a capacity provider. Therefore, when a generator does not sell some capacity but continues to remain in operation, it raises concerns that the unsold capacity may have been withheld in an attempt to raise prices above competitive levels.

In the NYISO capacity market, there are at least two factors that provide some competitive discipline and which may deter attempts to exercise market power. First, the capacity demand curve is sloped, so a generator that raises its offer price above competitive levels will sell a reduced quantity. Second, there is substantial import capability from neighboring areas, so an increase in price levels may attract increased imports that will further reduce the price impact resulting from an attempt to withhold supply. Ultimately, market power is often defined as having the ability to profitably raise prices above competitive levels by withholding supply, so if a generator tests the market by withholding supply but it does not profit from doing so, the behavior is likely to stop because the generator does not have market power. In any case, we closely evaluate in-service generating capacity that is not sold in the capacity market.

From July to October 2021, an average of nearly 200 MW of installed capacity went unsold in the monthly Spot Auctions. A small amount of this was due to what should be classified as administrative errors by several generators; however, an average of roughly 150 MW of the unsold capacity was offered at prices above the market clearing price.

Figure 32 below shows the unsold capacity from internal resources during each month of the 2021/22 Capability Year along with how capacity imports from external control areas changed each month. Unsold capacity from internal generation is designated by three categories:

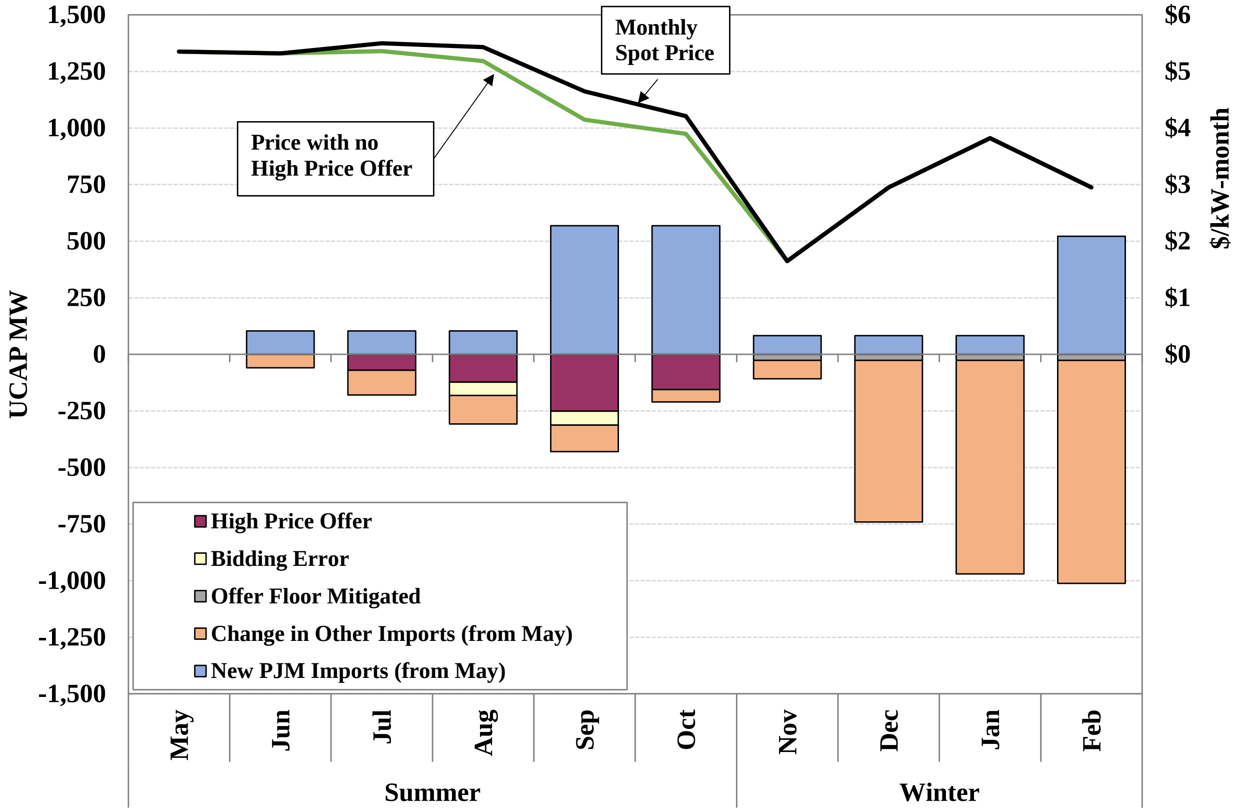
- High Offer Price: capacity that was offered into the Spot Auction but at prices above the Demand Curve.
- Bidding Error: capacity that was not offered into the Spot Auction due to administrative errors by several participants.
- Offer Floor Mitigated: capacity that was previously mitigated in the BSM process and subsequently had to offer above the demand curve.

Import capacity and unsold values from there are classified into three categories as well:

- New PJM Imports (from May): additional capacity sales from PJM after May 2021.
- Change in Other Imports (from May): changes in capacity sold from all other external control areas from the May 2021 baseline, excluding the new PJM imports.

On the secondary axis there are three values given. One shows the monthly spot auction prices as reported, containing all of the unsold capacity and new external capacity sales (as applicable). The green line below it shows the adjusted monthly spot auction prices had there been no unsold capacity from the High Offer Price category.[209] The region between the lines denotes the maximum possible price impact from the High Offer Price category, although the actual impact is smaller to the extent that unsold capacity attacted additional imports from PJM.

Figure 32: Unsold Capacity and Incremental Responses during 2021/22 Capability Year



The slope of the NYCA capacity demand curve dictates that, for the 2021 Summer Capability Period, each 100 MW of unsold UCAP resulted in an increase of $0.2004/kW-month in the capacity price.[210] Therefore, the unsold capacity may have increased capacity prices systemwide by as much as $0.30/kW-month on average between July and October 2021. However, the increase in unsold capacity coincided with an increase in imports from PJM, which fell in November after the decline in capacity prices. Although the Rest of State capacity regions does not have market power mitigation measures, the region is relatively large and the demand curve and potential for imports provide some competitive discipline in case a market participant attempts to withhold capacity.

209 Although offer floor mitigated UCAP is, definitionally, unsold, this value is not included in the price impact calculation since the offers are high by fiat through the BSM process.

210 See NYISO Translation of the Demand Curve here for more information on this.

X. DEMAND RESPONSE PROGRAMS

Participation by demand response in the market is beneficial for many reasons. Demand response contributes to reliable system operations, long-term resource adequacy, lower 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 – This is scheduled for implemention in the fourth quarter of 2022. which should allow individual large consumers and aggregations of consumers to participate more directly in the market and to 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 1,170 MW of demand response resources registered in New York are reliability demand response resources.[211]

211 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 1,170 MW of resources participating in 2021. The primary incentive to participate in this program is that SCRs can sell capacity in the NYISO's capacity market. However, the registered quantity of reliability program resources fell by more than 50 percent from 2010 to 2021 primarily because of enhancements to auditing and baseline methodologies for SCRs since 2011 (registered quantity did not change significantly each year from 2013 to 2021).[212] These have improved the accuracy of baselines for some resources, reducing the amount of capacity that 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.

In the six months of the Summer 2021 Capability Period, SCRs made contributions to resource adequacy by satisfying:

- An average of 4.1 percent of the UCAP requirement for New York City;
- An average of 3.3 percent of the UCAP requirement for the G-J Locality;
- An average of 0.6 percent of the UCAP requirement for Long Island; and
- An average of 2.8 percent of the UCAP requirement for NYCA.

The SCR contributions to resource adequacy fell modestly in 2021, partly because of the Expanding Capacity Eligibility market rules that became effective on May 1, 2021. All SCR resources are now required to have a 4-hour duration and their UCAP MWs reflect a Duration Adjustment Factor of 90 percent set currently for 4-hour resources.[213]

Demand-Side Ancillary Services Program

This program allows demand-side resources to offer operating reserves and regulation service in the wholesale market. Currently, five 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 can provide up to 175 MW of operating reserves. However, the NYISO will retire this program when DSASP resources become eligible to utilitze the Distributed Energy Resource ("DER") and Aggregation market rules.[214] In preparation for the retirement of the DSASP, the NYISO plans to stop accepting DSASP resource applications at 5:00 PM on May 2, 2022.

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212 See Figure A-133 in the Section VIII.A of the Appendix for more details.

213 See Section 4.1.1 of ICAP Manual for more details.

214 See market rules accepted by FERC on January 23, 2020 in Docket No. ER19-2276.

Day-Ahead Demand Response Program

No resources have participated in this program since 2010.

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 2021, the TDRP was activated for subzone J2 (roughly 30 MW) on two days at the end of June in response to Transmission Owner requests. Responses to TDRP activations are voluntary, and scarcity pricing is not applied.

The NYISO activated SCR resources for Long Island (< 40 MW) on six days in August. The scarcity pricing rule was only triggered for a total of five five-minute intervals during the August 25th event. Scarcity pricing was triggered very infrequently because the scarcity pricing rules depend in part on the reserve market requirement for the region where the SCR activations occur. As we discuss in Section V, there are two deficiencies in the reserve market related to Long Island that account for the lack of scarcity pricing during these events:

- The reserve market requirements are understated relative to the actual reliability needs in Long Island – Recommendation 2021-2 is intended to address this concern by raising the market requirement to reflect the full reliability need.
- The reserve clearing prices in Long Island do not consider the costs of satisfying the reserve market requirements for Long Island – Recommendation 2019-1 would address this by setting reserve clearing prices for Long Island that consider all of the reserve constraints that are binding in the market scheduling model.

In addition, demand response resources in local utility programs were activated on 12 days in 2021. The amount of these deployments exceeded 200 MW on 8 days and ranged up to 650 MW on one day, most of which was activated for peak-shaving in local TOs' servicing areas. Our analysis shows that these deployments helped avoid a brief NYCA capacity deficiency on just three days.[215] Prices in the wholesale energy market did not indicate a need for peak load reduction on the other days.[216]

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

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

216 Utility demand response resources are paid primarily for availability (including capacity). Utility programs often provide large payments (~$1,000/MWh) for peak-shaving that are far above the value of load reduction in the real-time market.

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. Peak-shaving also results in lower capacity requirements in future periods. It would be beneficial for the NYISO to work with TOs to evaluate the feasibility and appropriateness of including utility demand response deployments in its market scheduling and pricing processes.

XI. RECOMMENDATIONS

Our analysis in this report indicates that the NYISO electricity markets performed well in 2021, although we recommend additional enhancements to improve market performance. Nineteen recommendations are presented in four 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 2020 SOM Report, but Recommendations #2021-1 to #2021-4 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>V.G</td><td>Model local reserve requirements in New York City load pockets.</td><td rowspan="2">Study completed in 2021; Dynamic Reserves project targets market design concept proposal in 2022.</td></tr>
<tr><td>2015-16</td><td>V.A</td><td>Dynamically adjust operating reserve requirements to account for factors that change the amount of reserves that must be held on internal resources.</td></tr>
<tr><td>2016-1</td><td>V.E</td><td>Consider rules for efficient pricing and settlement when operating reserve suppliers provide congestion relief.</td><td></td></tr>
<tr><td>2017-2</td><td>V.A</td><td>Modify operating reserve demand curves to improve shortage pricing and ensure NYISO reliability.</td><td></td></tr>
<tr><td colspan="4">Capacity Market – Design Enhancements</td></tr>
<tr><td>2021-4</td><td>VII.E</td><td>Improve capacity modeling and accreditation for specific types of resources.</td><td>Improving Capacity Accreditation Phase II process underway.</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			
2021-1	V.G	Evaluate need for longer lead time reserve products to address increasing operational uncertainties.	Grid in Transition 2022 study may provide useful analysis.
2021-2	V.G, V.H	Model full reserve requirements for Long Island.	
2021-3	V.G, VI.B	Consider modeling transient voltage recovery constraints on Long Island in the energy market.	
2019-1	V.G, X	Set day-ahead and real-time reserve clearing prices considering reserve constraints for Long Island.	*Dynamic Reserves* targets 2022 market design concept proposal.
2015-9	VIII.C	Eliminate transaction fees for CTS transactions at the PJM-NYISO border.	
2015-17	V.A	Utilize constraint-specific graduated transmission demand curves to set constraint shadow prices during transmission shortages.	Partial changes approved by stakeholders in 2021. *Lines in Series* 2022 project underway.
Energy Market Enhancements – Real-Time Market Operations			
2020-1	V.D	Consider enhancements to the scheduling of duct-firing capacity in the real-time market that more appropriately reflects its operational characteristics.	*Improve Duct-Firing Modeling* 2022 Project underway.
2020-2	V.A	Eliminate offline fast-start pricing from the real-time dispatch model.	
2012-8	V.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	VIII.C	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 – 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.	
2012-1c	VII.F	Grant financial capacity transfer rights between zones for market-based transmission upgrades that help satisfy planning reliability needs.	
Planning Process Enhancements			
2015-7	VII.G	Reform the transmission planning process to better identify and fund economic transmission investments.	

This section describes each recommendation and their expected benefits, identifies the section of the report that discusses them in more detail, and describes the status if there is a current NYISO project or initiative designed to address the recommendation. The last subsection discusses several prior recommendations that we 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 most cases, our recommendations provide high-level changes, 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.

In each report, we designate a few recommendations as "High Priority" based on our assessment of their effects on market efficiency or, in some cases, the magnitude of the market or pricing issue. When possible, we quantify a recommendation's benefits by estimating the production cost savings and/or investment cost savings it would produce because these are the most accurate measures of economic efficiency. We focus on maximizing economic efficiency because this will minimize the costs of satisfying the system's needs over the long-term. We do not use other potential measures that focus largely on economic transfers associated with changing prices, such as consumer savings, because they do not measure economic efficiency.

In addition to these considerations, we often consider the feasibility and cost of implementation. Relatively quick or low-cost recommendations generally warrant a higher priority because they produce higher benefit-to-cost ratios. 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

2021-1: Evaluate need for longer lead time reserve products to address increasing operational uncertainties (Current Effort)

The NYISO currently operates markets for 30-minute, 10-minute and 10-minute spinning operating reserves. These products provide the system flexibility to respond to unexpected contingencies in real time by converting reserve suppliers to energy with relatively short notice. There is a growing set of possible situations where larger quantities of reserves are needed over longer time horizons. For example, generators are routinely committed out-of-market in New York City load pockets to satisfy multiple contingency requirements that could be satisfied by resources with longer response times. In the long term, entry of intermittent renewables is expected to lead to large deviations of net load from the forecast over multiple hours.[217] Procuring some of the additional reserves from resources with longer response times would allow NYISO to cost-effectively maintain security and reliability in these situations, since a larger set of resources can provide reserves over longer time intervals. It would also allow these out-of-market actions to be priced more efficiently to the extent that these actions could occur through the market by deploying a longer-lead time reserve product.

We recommend that NYISO evaluate the need for longer lead time reserve products of up to four-hours. Such products could allow NYISO to address reliability needs more efficiently and avoid the use of out of market commitments to secure against multi-hour net load ramps. This would also provide better incentives for building and maintaining flexible resources that help integrate renewables. This evaluation should also consider the impact of energy limitations on a resource's eligibility to provide reserves over a given timeframe.

2021-2: Model full reserve requirements for Long Island

The current Long Island reserve requirement is usually adequate to maintain security and reliability following the largest contingency, but it is necessary to hold reserves on Long Island to satisfy N-1-1-0 criteria (i.e., normal line loading following the two largest contingencies). Because this requirement is not included in the market software, system operators frequently relied on out-of-market commitments in 2021.[218] Modeling the full reserve requirements for Long Island would improve efficiency and encourage new resources to locate where they are most valuable. Hence, we recommend that the NYISO implement local reserve requirements in Long Island that are adequate to maintain reliability rather than rely on out-of-merit actions. This will likely require sufficient reserves to satisfy N-1-1-0 criteria.

2021-3: Consider modeling transient voltage recovery constraints on Long Island in the energy market

Transient voltage recovery (TVR) criteria for the East End of Long Island are not represented in the market software, so TVR criteria is frequently satisfied by scheduling generation out-of-market during the summer.[219] This sometimes leads to inefficient generation scheduling and fails to provide efficient incentives to resources that can contribute to satisfying TVR criteria. Hence, we recommend that NYISO satisfy these criteria in the day-ahead and real-time markets using surrogate constraints, so that generation scheduled to satisfy TVR criteria for the East End

217 NYISO's *2021-2030 Comprehensive Reliability Plan* finds that in a long-term scenario with all goals of the Climate Leadership and Community Protection Act (CLCPA) met, maximum winter ramp requirements could exceed 10 GW over an hour and 25 GW over a six-hour period.

218 See discussion in Section V.G. Also see our Q3 2021 Quarterly Report on the NYISO markets (pages 11 and 76), available here.

219 See discussion in Section VI.B.

of Long Island are compensated appropriately. Appendix III.E illustrates how surrogate constraints could be used to satisfy TVR criteria within the market models.

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.[220] This recommendation is particularly important if Recommendation 2021-2 to model local reserve requirements in Long Island load pockets is adopted, so that price signals attract and utilize resource in those load pockets efficiently.

Status: In 2021, the NYISO performed a study of dynamic reserve scheduling (see Recommendation 2015-16) that recommended considering pricing of Long Island reserves in future years.[221]

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 can satisfy the local requirements.[222] Hence, we recommend the NYISO implement local reserve requirements in the New York City load pockets.

220 2022 Project Candidate: *Long Island Reserve Constraint Pricing* and 2022 project *Dynamic Reserves*.

221 See Recommendation #4 in NYISO's December 2021 "Reserve Enhancements for Constrained Areas (Dynamic Reserves)" study, available here.

222 See discussion in Section V.G and Appendix VII.D.

We designate this recommendation as High Priority partly because of significant transmission and resource mix changes planned for New York City over the next five to ten years.[223] New transmission and the retirement of peaking generation will shift the location of reserve-constrained areas from relatively localized load pockets to larger load pockets within New York City. Further, the interconnection of offshore wind generation in New York City will lead to larger and more variable operating reserve requirements. Localized operating requirements will help the NYISO maintain reliability efficiently by providing better incentives for investment in new and existing resources that can provide reserves at a low cost.

Status: The NYISO conducted a study in 2021 under its *Reserve Enhancement for Constrained Areas* project. The study recommended that NYISO consider modeling load pocket reserve requirements in New York City along with dynamic reserve scheduling.[224] We also encourage NYISO to consider whether local reserve requirements should consider the loss of multiple generators due to a natural gas system contingency, rather than soley based on the loss of two Bulk System transmission elements. The 2022 NYISO Market Project *Dynamic Reserves* aims to incorporate New York City load pocket reserve requirements into the market software and aims to propose a market design concept by Q4 2022.[225] We encourage NYISO to continue supporting this effort.

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

Shortage prices during operating reserve deficiencies are currently too low to adequately encourage market participants to take actions that preserve reliability during critical conditions. This is because the demand for operating reserves in the market do not fully reflect their value in ensuring the load is served, or the value-of-lost-load ("VOLL"). In addition to failing to schedule resources and incent resource actions that will help avoid load-shedding in the short-term, this reduces the incentive to replace inflexible and poor-performing resources with fast-ramping generation and storage in the longer-term.[226] The shortage prices are also sometimes too low to schedule available resources that are needed to satisfy reliability requirements, which compels operators to resort to out-of-market actions to preserve reliability.

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223 ConEd's Local Transmission Plan includes three new PAR-controlled lines to replace retiring peakers in the Astoria East/Corona and Greenwood/Fox Hills load pockets. See ConEdison, *CECONY's Updated Local Transmission Plan*, presented to Electric System Planning Working Group on January 25, 2021.

224 See December 14, 2021 ICAPWG presentation "Reserve Enhancements for Constrained Areas (Dynamic Reserves): Study Findings/Recommendations". The full study is available here.

225 See January 20, 2022 ICAPWG presentation "2022 Market Projects".

226 See discussion in Appendix Section VII.D.

This problem is exacerbated by the implementation of PFP ("Pay For Performance") rules in ISO New England and PJM, which result in much higher incremental compensation for energy and reserves during reserve shortages in NYISO's neighbors. Resources selling into ISO-NE and PJM could receive over $8,000 per MWh during even slight shortages of 10-minute and 30-minute reserves, while NYISO sets prices between $750 and $3,000 per MWh during *deep* 10-minute and 30-minute shortages.[227] This will likely result in inefficient imports and exports during tight regional conditions, negatively affecting NYISO's reliability as energy is drawn to neighboring markets even when shortages in NYISO are much deeper.

Status: The NYISO implemented revised reserve demand curves in summer 2021. The changes increased the quantity of NYCA 30-minute reserves that are assigned the current maximum shadow price of $750/MWh and added demand curve steps at higher levels that should reduce the need for out-of-market actions to maintain reliability.[228] However, the reserve demand curve levels still remain far below levels needed to: (a) avoid out-of-market actions when neighboring control areas also experience reserve shortages and (b) properly reflect the value of reserves for avoiding load shedding during deep reserve shortages.

Hence, we recommend that the NYISO modify 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 ("VOLL") and the risk of load shedding given the depth of the reserve shortage;
- The incentive effects of neighbors' PFP rules are minimized; and
- The real-time market schedules available resources so that NYISO operators do not need to engage in out-of-market actions to maintain reliability.

This recommendation is high priority because the need for resources to be responsive to emergency conditions in real time will become increasingly important. The entry of intermittent renewables and retirement of conventional generators is likely to increase net load forecast uncertainty and create new operational challenges. This recommendation will improve incentives for generation and load flexibility and efficient usage of regional resources to preserve reliability. 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. (High Priority)

227 See discussion in Section V.A.

228 See FERC docket ER21-1018 and NYISO Project *Ancillary Services Shortage Pricing*.

The NYISO is required to maintain flows such that if a contingency were to occur, no transmission facility would be loaded above its Long-Term Emergency ("LTE") rating post-contingency. In some cases, the NYISO is allowed to use operating reserves and other post-contingency operating actions to satisfy this requirement. This allows the NYISO to increase utilization of the transmission system into load centers, thereby reducing production costs and pollution in the load center. Since these operating reserve providers are not compensated for helping manage congestion, the market does not provide efficient signals for investment in new and existing resources with flexible characteristics. Hence, we recommend the NYISO evaluate means to efficiently compensate operating reserves that help manage congestion.[229]

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 $0.8 million in 2021 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.[230]

229 We describe a conceptual approach to providing efficient compensation in this report. See discussion in Section V.E, Appendix V.L, and Appendix VII.D.

230 See Section VIII.C. See 2022 Project Candidate: *Eliminate Fees for CTS Transactions with PJM*.

2015-16: Dynamically adjust operating reserve requirements to account for factors that change the amount of reserves that must be held on internal resources. (Current Effort, High Priority)

The amount of operating reserves that must be held on resources in many local areas can be reduced when there is unused import capability into the areas. In many cases, it is less costly to produce more energy from resources in an area, reducing the flows into the area and treating the unused interface capability as reserves. This report outlines how local reserve requirements and associated price signals could be determined dynamically based on load, transmission capability and online generation. 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. Section V.L of the Appendix describes a mathematical modeling approach to determine dynamic reserve requirements. We recommend that the NYISO modify the market software to optimize the quantity of reserves procured for each of the requirements described below.[231]

In some cases, the operating reserve requirements above could be satisfied with resources having lead times longer than 30 minutes (rather than 10-minute and 30-minute reserve providers). Accordingly, we have recommended that the NYISO evaluate the need for longer leadtime reserve products (see Recommendation #2021-1). Before longer lead time reserve products have been created, the most efficient way to represent such requirements may be with a 30-minute reserve requirement in the market models. The NYISO should consider these tradeoffs in its evaluation of Dynamic Reserves.

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 resource mix evolves over the coming decade.

Status: In 2021, NYISO conducted a study under its *Reserve Enhancements for Constrained Areas* project (the "RECA Study") that developed a prototype for dynamic reserve scheduling and concluded that such an approach is feasible. The *Dynamic Reserves* project underway in 2022 aims to establish market design proposals considering the study's findings. We identify six examples where dynamic reserve functionality would provide significant benefits below and comment on the treatment of each of them in the RECA Study:

- *Long Island reserve requirements* – Resources in Zone K are limited in satisfying operating reserve requirements for SENY, Eastern NY, and NYCA, but the amount of 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

[231] See discussion in Section V.A. See Section V.L of the Appendix for a potential mathematical modeling approach. See 2021 Project Candidate: *Reserve Enhancements for Constrained Areas*.

on Long Island to support the requirements outside of Long Island. Converting Long Island reserves to energy in these cases would be accomplished by simply reducing imports to Long Island, thereby reducing the required generation outside of Long Island.

- ✓ The prototype analyzed by NYISO in the RECA Study would address this by allowing additional reserves to be scheduled on Long Island to support requirements in other areas, and vice versa.

- *Eastern and Southeastern New York reserve requirements* – Operating reserve requirements can be satisfied more efficiently by holding reserves on the interfaces into Eastern New York or into SENY.
  - ✓ The prototype analyzed by NYISO in the RECA Study would address this by setting reserve requirements dynamically and allow available transmission capacity to reduce local reserve needs.
- *HQ-NYCA imports* – 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 prototype analyzed by NYISO in the RECA Study would address this by allowing HQ interface limits to increase while scheduling additional reserves when it is economic to do so.
- *NYCA reserve requirement* – The reserve market requirement is frequently satisfied in the day-ahead market by under-scheduling physical energy supply needed to satisfy the forecast load. Under peak conditions, this can lead to insufficient total day-ahead market commitment, leading the NYISO to commit generation out-of-market. This 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 commits and prices resources efficiently.
  - ✓ The prototype analyzed by NYISO in the RECA Study would not address this. We recommend NYISO incorporate this feature into its Market Design Concept proposal in the 2022 Dynamic Reserves project.
- *New York City zone-level and load pocket reserve requirements* – If the NYISO implements recommendation 2017-1, operating reserve requirements may be satisfied more efficiently by holding some of the local reserves on the interfaces into New York City and its load pockets. This will become particularly important when offshore wind is added to New York City because it will allow the NYISO to utilize the wind output and free up interface capability into the load pockets that can hold reserves.
  - ✓ NYISO is considering modeling NYC load pockets as part of its 2022 *Dynamic Reserves* project, and the prototype analyzed by NYISO in the RECA Study would allow those requirements to be set dynamically.
- *Allow manual operator adjustments to reserve requirements as necessary* – Currently, when a NYISO operator identifies a temporary condition requiring additional operating reserves in a specific area, the operator manually commits generation to increase available reserves. This may be justified by system conditions, but it undermines

efficient pricing and market incentives by artificially injecting additional supply into the market. Instead, we recommend allowing the operator to increase the reserve requirement for the appropriate area, so that the reliability need can be met through the day-ahead and real-time market scheduling processes.

- ✓ The prototype analyzed by NYISO in the RECA Study did not address this. We recommend NYISO incorporate this feature into its Market Design Concept proposal in the 2022 Dynamic Reserves project.

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 was 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.

Status: The NYISO has advanced a project that would largely implement this recommendation by aligning GTDCs with the actual constraint reliability margin (CRM) of specific transmission facilities.[232] These enhancements were approved by stakeholder vote at NYISO's Management Committee in October 2021. NYISO is currently developing functional requirements to implement these changes and evaluating changes to the application of transmission shortage pricing when multiple transmission constraints (such as lines in series or contingency combinations) are active.[233] We support the NYISO's project as a significant enhancement.

<u>Energy Market Enhancements – Real-Time Market Operations</u>

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

232 See discussion in Section V.A. See 2022 Market Project: *Constraint Specific Transmission Shortage Pricing*.

233 See NYISO MIWG/ICAPWG presentations on "Constraint Specific Transmission Shortage Pricing" and "Lines in Series" / "Multiple Active Transmission Constraints".

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 800 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.[234] We recommend NYISO evaluate 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.

Status: The NYISO is pursuing a 2022 Market Project to explore changes to accommodate the operating capability of CCGTs when they are in the duct-firing region and called upon to provide reserves.[235] The NYISO also intends to explore related changes to the Regulation product if necessary (since many units cannot provide regulation and use duct firing simultaneously). The project's target deliverable is a Market Design Concept Proposed in Q3 2022.

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.[236] We recommend that NYISO eliminate the feature which is known as offline fast-start pricing.

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 2021, 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) 98 percent of the time. We estimate that their operation increased production costs by $10

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234 See discussion in Section V.D.

235 See 2022 Market Project *Improve Duct-Firing Modeling*.

236 See discussion in Section V.A and 2022 Project Candidate *Eliminate Offline GT Pricing*. This project was not prioritized for 2022 but is included in NYISO's 2021 Master Plan with deployment targeted for 2024.

million. Furthermore, we estimate that their operation increased New York State emissions of carbon dioxide by 1.4 percent (426 thousand tons) and nitrous oxide by 7.8 percent (606 tons).[237]

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: [238]

a) 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.
b) 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.
c) Enable RTD to delay the shut-down of a gas turbine for five minutes when it is economic to remain on-line.
d) 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.
e) 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.
f) 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).

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[237] See discussion in Section V.F. See 2022 Project Candidate: *Long Island PAR Optimization & Financial Rights*.

[238] See discussion in Sections VIII.C. See 2021 Project Candidate: *RTC-RTD Convergence Improvements*.

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.

Capacity Market – Design Enhancements

2021-4: Improve capacity modeling and accreditation for specific types of resources.

The NYISO filed tariff revisions in 2022 that would set resources' capacity credit annually based on their marginal contribution to reliability, beginning in the 2024/25 capability year. A resource type's Capacity Accreditation Factor will be calculated based on the impact of an incremental amount of that resource type on the reliability metric (e.g. LOLE) in NYISO's resource adequacy model GE MARS. These changes establish a framework for efficiently compensating resources in the capacity market. However, limitations in current MARS modeling techniques may prevent some resource types from being evaluated as accurately as possible:

a) Winter fuel limitations – MARS does not model limits on the output of gas-fired units without backup fuel that are jointly unavailable during extreme cold weather;
b) Energy storage modeling – MARS uses a simplified method to dispatch energy limited resources that could better reflect strategic dispatch under imperfect foresight;
c) Resource/Load Correlations – MARS models renewable output shapes independently of load shapes, but these are correlated in practice because both are driven by weather. Similarly, MARS does not model the effect of behind-the-meter solar on load shapes;
d) Inflexible Resources – MARS does not accurately model the availability of inflexible units with long startup lead times because it assumes they are always committed and available; and
e) Conventional Generators Receiving Excessive Credit – Several categories of generation receive excessive credit under current rules, including (i) generators with ambient water temperature restrictions under peak summer conditions, (ii) emergency generating capacity that cannot be deployed in real-time with the existing market software, and (iii) generators receiving EFORd values that overstate their reliability in critical hours due to frequent off-peak operation.

We recommend that NYISO consider improvements to more accurately evaluate marginal reliability contributions for: (a) gas-only generators with limited/no backup fuel, (b) energy limited resources, (c) resources whose availability is correlated with load, (d) inflexible generators, and (e) conventional generators receiving excessive capacity credit.[239]

[239] See discussion in Section VII.E. Also see discussion of functionally unavailable capacity on high load days in our Q3 2021 Quarterly Report on the NYISO markets (pages 23 and 87), available here.

NYISO should develop changes to MARS needed for accurate capacity accreditation directly, while working with the New York State Reliability Council (NYSRC) to include these changes in IRM studies expeditiously. Where it is not possible to derive a resource type's marginal reliability contribution directly from MARS, NYISO should consider a heuristic approach that would apply a settlement adjustment or discount to UCAP based on availability during actual reserve shortages.

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).[240] 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.

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. Reliance on four fixed capacity zones will also prevent the current market from responding to significant resource additions, retirements, or transmission network changes.

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

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.[241] 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.

We designate this recommendation as high priority because it would produce sizable economic and reliability benefits over the long term. In particular, it 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 for market-based transmission upgrades that help satisfy planning reliability needs.

This is similar to the NYISO's current rules to provide Transmission Congestion Contracts ("TCCs"). New transmission projects can increase transfer capability over interfaces that bind in the NYISO's capacity market. Hence, transmission projects can provide resource adequacy benefits that are comparable to capacity from resources in constrained areas. Accordingly, transmission should be compensated for the resource adequacy benefits through the capacity market. Creating financial capacity transfer rights will help: (a) provide efficient incentives for economic transmission investment when it is less costly than generation and DR alternatives, and (b) reduce barriers to entry that sometimes occur under the existing rules when a new generation project is required to make uneconomic transmission upgrades.[242]

Enhance Planning Processes

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

The current economic transmission planning process does not accurately estimate the economic benefits of proposed projects when evaluating their eligibility for cost recovery. We identify in this report several key assumptions and procedural issues that lead transmission projects to be systematically under-valued. Recommended improvements include:

- Valuation of the transmission project's capacity benefits;
- More realistic modeling of incoming new generation driven by policy requirements; and

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

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

- Revise current overly restrictive requirement that 80 percent of beneficiaries vote in favor.

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.[243] A functional economic planning process will provide a path for valuable bulk-system transmission projects that are not specifically identified in the Public Policy Transmission Planning Process.

FERC approved tariff revisions in 2021 that revised aspects of the economic planning process, focused on making the initial system assessment phase more flexible and informative.[244] We support these improvements, and encourage NYISO to pursue changes to the project evaluation stage that would facilitate economic transmission projects.

C. Discussion of Recommendations Made in Previous SOM Reports

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

Market Developments Since the 2020 SOM Report

The NYISO has moved forward with market reforms in response to the following recommendations from the 2020 State of the Market Report:

<u>*2018-1:*</u> *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* – NYISO has established a process to periodically review OOM actions on Long Island and model associated 69 kV constraints if needed. In April, 2021, the NYISO began securing two 69 kV circuits in the market software that were among the most significant drivers of OOM dispatch and PAR operations that affect flows on the 138 kV system. In April, 2022, the NYISO began securing two additional facilities. This process should significantly improve the efficiency of prices and schedules in Long Island. However, the NYISO continues to manage TVR issues on

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243 See discussion in Section VII.G.

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

the low-voltage system on the East End of Long Island using out-of-merit dispatch of generation. New Recommendation #2021-3 urges the NYISO to consider TVR issues through the market models.

2020-3: *Revise the capacity accreditation rules to compensate resources in accordance with their marginal reliability value* – The NYISO developed capacity accreditation rules based on marginal reliability value in 2021, as part of its Comprehensive Mitigation Review stakeholder process. The NYISO filed tariff changes with FERC on January 5, 2022 and proposed to implement new capacity accreditation rules beginning in the 2024/25 capability year. See FERC Docket ER22-772 and NYISO ICAPWG documents on Comprehensive Mitigation Review. FERC approved these on May 10, 2022.

2019-5: *Translate demand curve reference point from ICAP to UCAP terms based on the demand curve unit technology* – NYISO included changes that would address this recommendation in its Comprehensive Mitigation Review tariff filing (FERC Docket ER22-772). FERC approved these on May 10, 2022.

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* – The NYISO filed tariff changes that address this recommendation with FERC in 2020. The proposed changes were accepted by FERC on February 17, 2022. See FERC Docket ER20-1718.

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* – We consider this recommendation to be resolved by FERC's February 2022 order accepting NYISO's proposed Part A Enhancements (ER20-1718).

2013-2d: *Enhance Buyer-Side Mitigation Forecast Assumptions to deter uneconomic entry while ensuring that economic entrants are not mitigated* – We consider this recommendation to be no longer necessary following FERC's February 2022 order accepting NYISO's proposed Part A Enhancements (ER20-1718).

2017-3: *Modify mitigation rules to address deficiencies in the current rule related to uneconomic over-production* – The NYISO filed tariff changes that address this recommendation with FERC in 2021. NYISO's proposal amends its market power mitigation measures to better address uneconomic over-production where a generator can profit from over-producing and being paid to relieve the resulting congestion in real-time, and to better account for generators with negative marginal costs. The proposed changes were accepted by FERC on February 18, 2022. See FERC Docket ER22-705.

Other Recommendations Not Included on the List for 2021

2017-4*: Modify mitigation rules to deter the use of fuel cost adjustments by a supplier to economically withhold* – We previously identified potential gaps where mitigation rules may not adequately deter withholding behavior in certain situations. In the ensuing years, we have not observed significant market impacts from this issue. We continue to monitor market participants' behavior and may re-issue a similar recommendation in the future if necessary.

2019-2*: Adjust offer/bid floor from negative $1000/MWh to negative $150/MWh* – We have removed this recommendation due to lack of stakeholder support and relatively minor expected benefits.

2014-9*: Consider enhancing modeling of loop flows and flows over PAR-controlled lines to reflect the effects of expected variations more accurately* – While we believe that implementing this recommendation would provide some value in the form of more efficient scheduling, we do not recommend pursuing it at this time because the level of effort and cost involved would be large relative to the expected benefit compared to other recommendations.

Analytic Appendix

2021 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 2021 in the following areas:

- Wholesale market prices;
- Fuel prices, and generation by fuel type;
- Fuel usage under tight gas supply conditions;
- Emissions from internal generators;
- 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

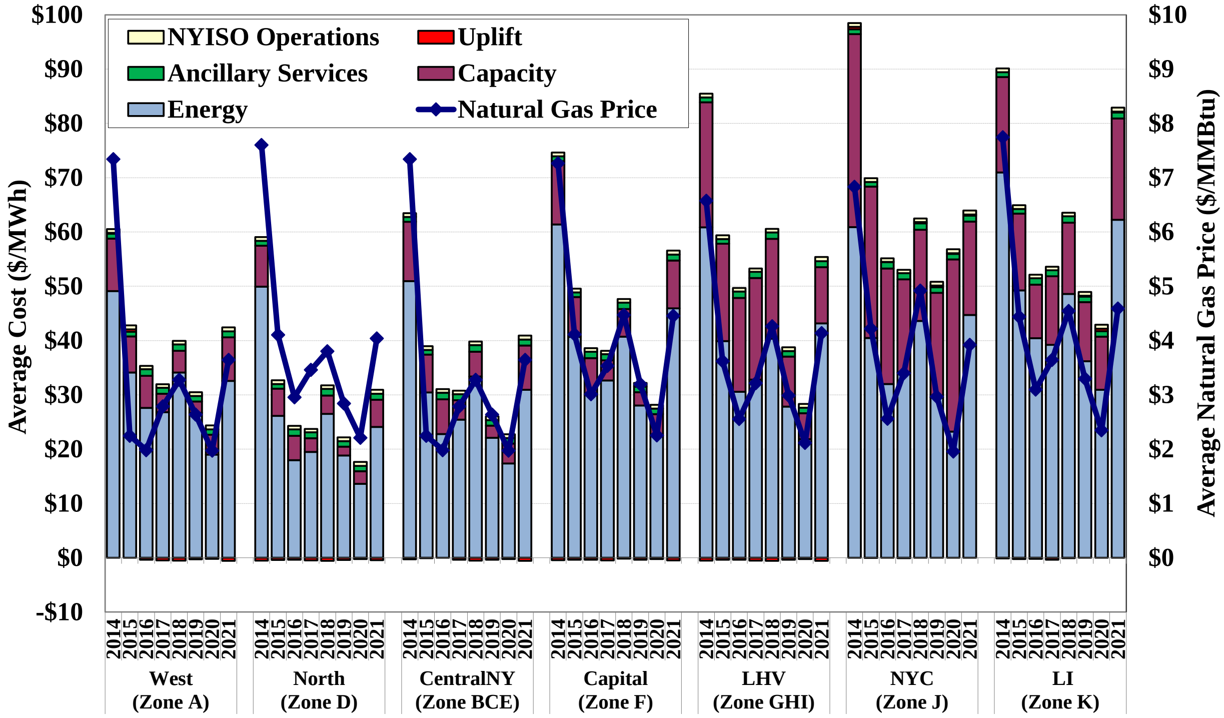
Figure A-1: Average All-In Price by Region

The first analysis summarizes the total costs of serving load from the NYISO markets as the all-in price for electricity as the sum of the energy and other wholesale market costs. 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 since 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 2014 to 2021 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

2014 – 2021



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.[245] 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.

245 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.

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 2021 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 2020 and 2021. 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.[246]

Figure A-2: Day-Ahead Electricity Prices and Natural Gas Costs
By Month, 2021

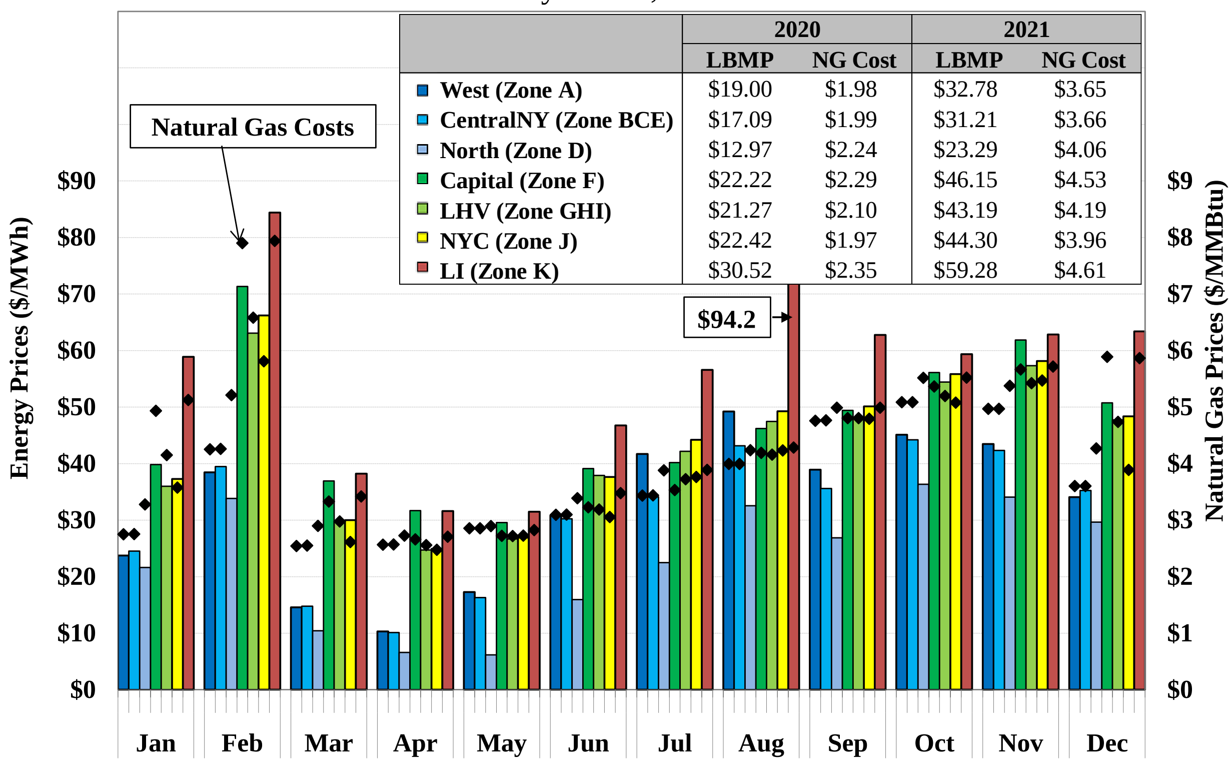


Figure A-3: Average Monthly Implied Marginal Heat Rate

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

The *Implied Marginal Heat Rate* equals the day-ahead electricity price minus a generic unit Variable Operations and Maintenance ("VOM") cost then divided by the fuel cost that includes the natural gas cost and greenhouse gas emission cost (i.e., RGGI Allowance Cost).[247] Thus, if

246 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.

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

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.[248]

Figure A-3 shows the load-weighted average implied marginal heat rate in each month of 2021 for the seven locations shown in Figure A-1 and in Figure A-2. The table in the chart shows the annual averages of the implied marginal heat rates in 2020 and in 2021 at these seven locations. By adjusting for the variation in natural gas prices, the implied marginal heat rate shows more clearly the seasonal variation in electricity prices.

Figure A-3: Average Monthly Implied Marginal Heat Rate
Day-Ahead Market, 2021

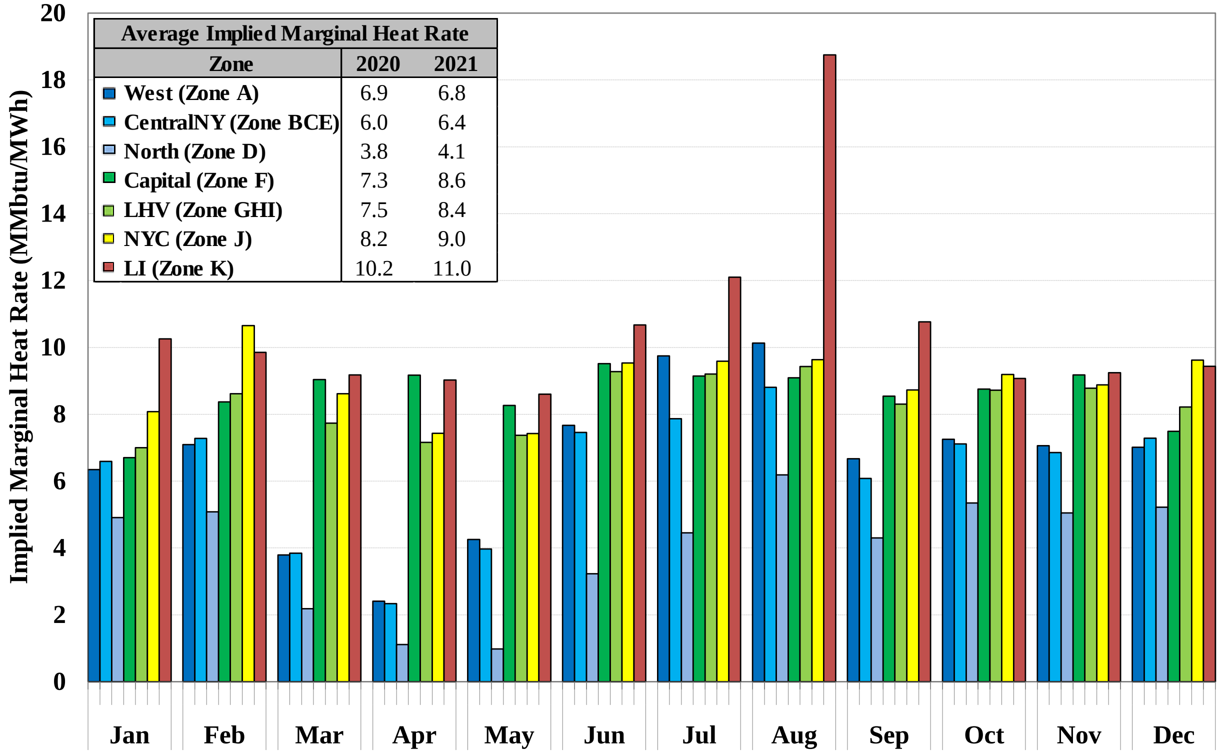


Figure A-4 – Figure A-5: Price Duration Curves and Implied Heat Rate Duration Curves

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 2021, 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

248 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.

on the vertical axis. The table in the chart shows the number of hours in 2021 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.[249] Fuel price changes from year to year are more apparent in the flatter portion of the price duration curve, since fuel price changes affect power prices most in these hours.

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

2021

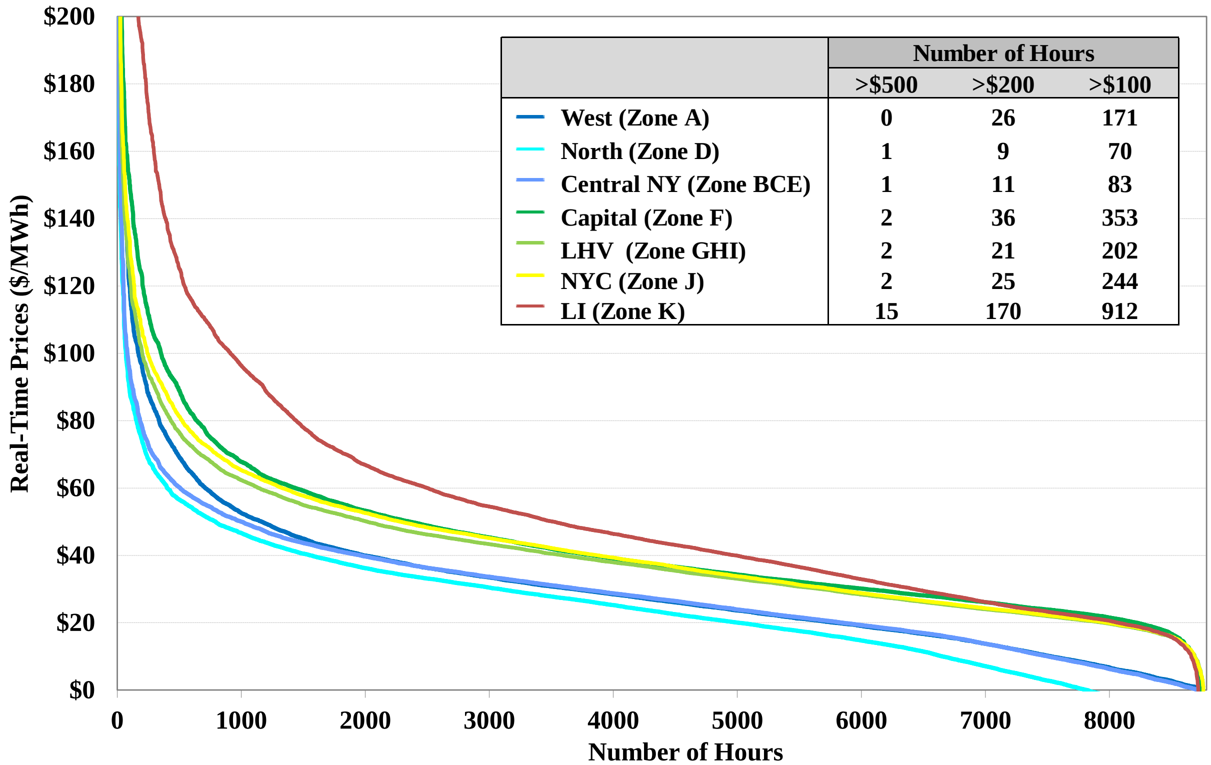
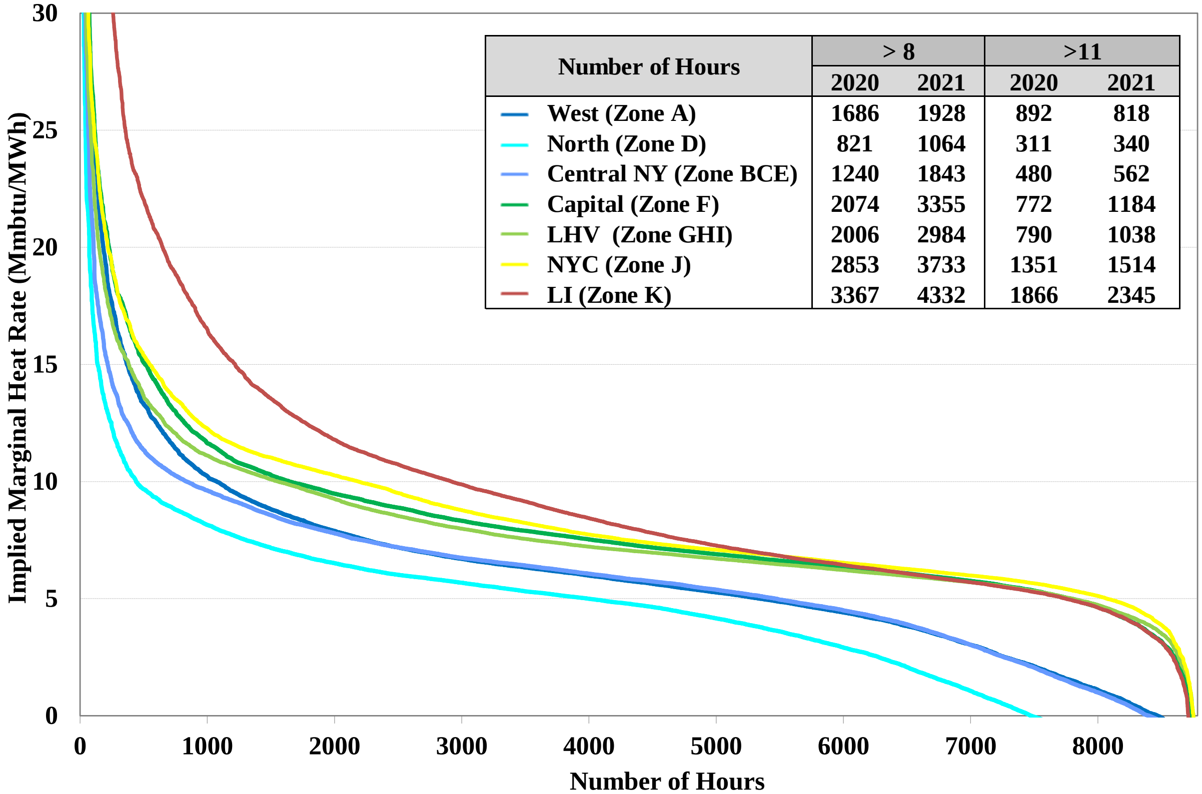


Figure A-5 shows the implied marginal heat rate duration curves at each location from the previous chart during 2021. Each curve shows the number of hours on the horizontal axis when the implied marginal heat rate for each sub-region was greater than the level shown on the vertical axis. The calculation 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 2020 and 2021.

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

Figure A-5: Implied Heat Rate Duration Curves by Region
2021



Number of Hours	> 8		>11	
	2020	2021	2020	2021
West (Zone A)	1686	1928	892	818
North (Zone D)	821	1064	311	340
Central NY (Zone BCE)	1240	1843	480	562
Capital (Zone F)	2074	3355	772	1184
LHV (Zone GHI)	2006	2984	790	1038
NYC (Zone J)	2853	3733	1351	1514
LI (Zone K)	3367	4332	1866	2345

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.[250] 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.[251] Since most large steam units can

250 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.

251 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.

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.[252]

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

- Tennessee Zone 6 prices are representative of gas prices in Capital Zone 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 2018 to 2021. The table compares the annual average fuel prices for these four years. [253]

Figure A-7 shows the quantities of generation by fuel type in seven regions of New York in each quarter of 2021 as well as for NYCA as a whole.[254] The table in the chart shows annual average generation by fuel type from 2019 to 2021.

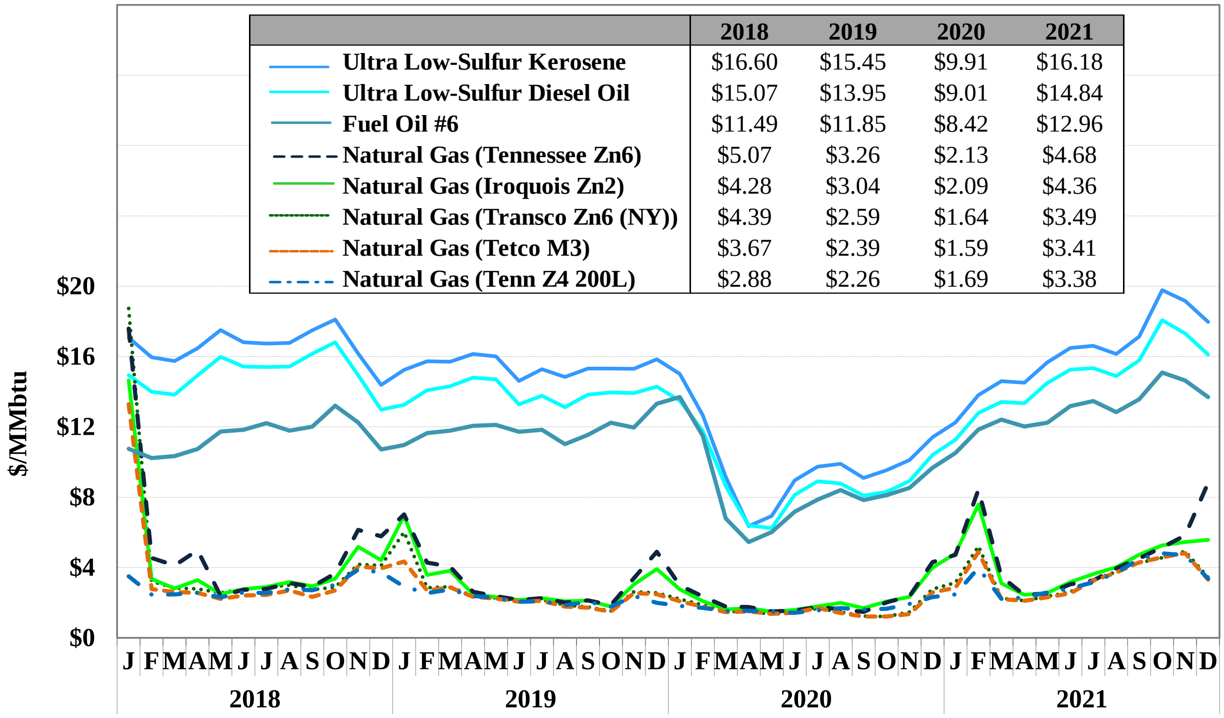
252 Emissions restrictions have tightened over the past years such that some steam turbines in New York City burn a No. 4 residual fuel oil blend.

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

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

Figure A-6: Monthly Average Fuel Index Prices

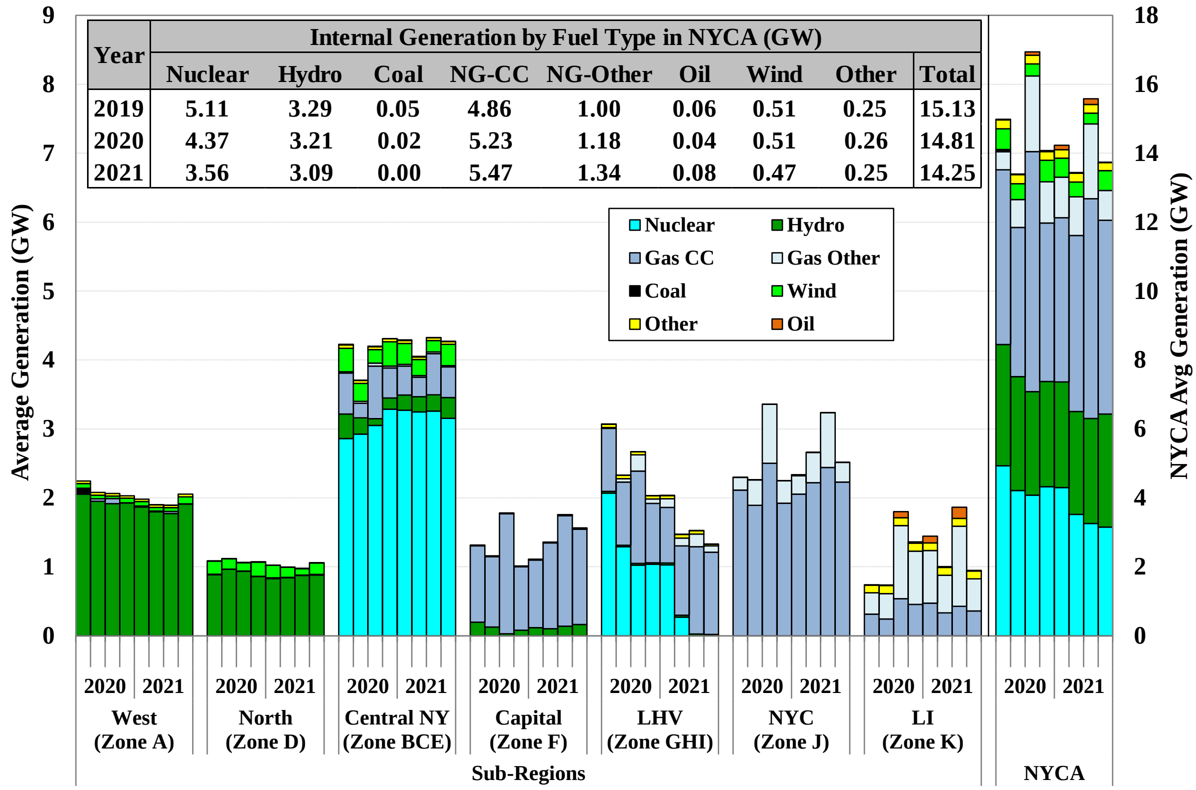
2018 – 2021



	2018	2019	2020	2021
Ultra Low-Sulfur Kerosene	$16.60	$15.45	$9.91	$16.18
Ultra Low-Sulfur Diesel Oil	$15.07	$13.95	$9.01	$14.84
Fuel Oil #6	$11.49	$11.85	$8.42	$12.96
Natural Gas (Tennessee Zn6)	$5.07	$3.26	$2.13	$4.68
Natural Gas (Iroquois Zn2)	$4.28	$3.04	$2.09	$4.36
Natural Gas (Transco Zn6 (NY))	$4.39	$2.59	$1.64	$3.49
Natural Gas (Tetco M3)	$3.67	$2.39	$1.59	$3.41
Natural Gas (Tenn Z4 200L)	$2.88	$2.26	$1.69	$3.38

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

By Quarter by Region, 2021

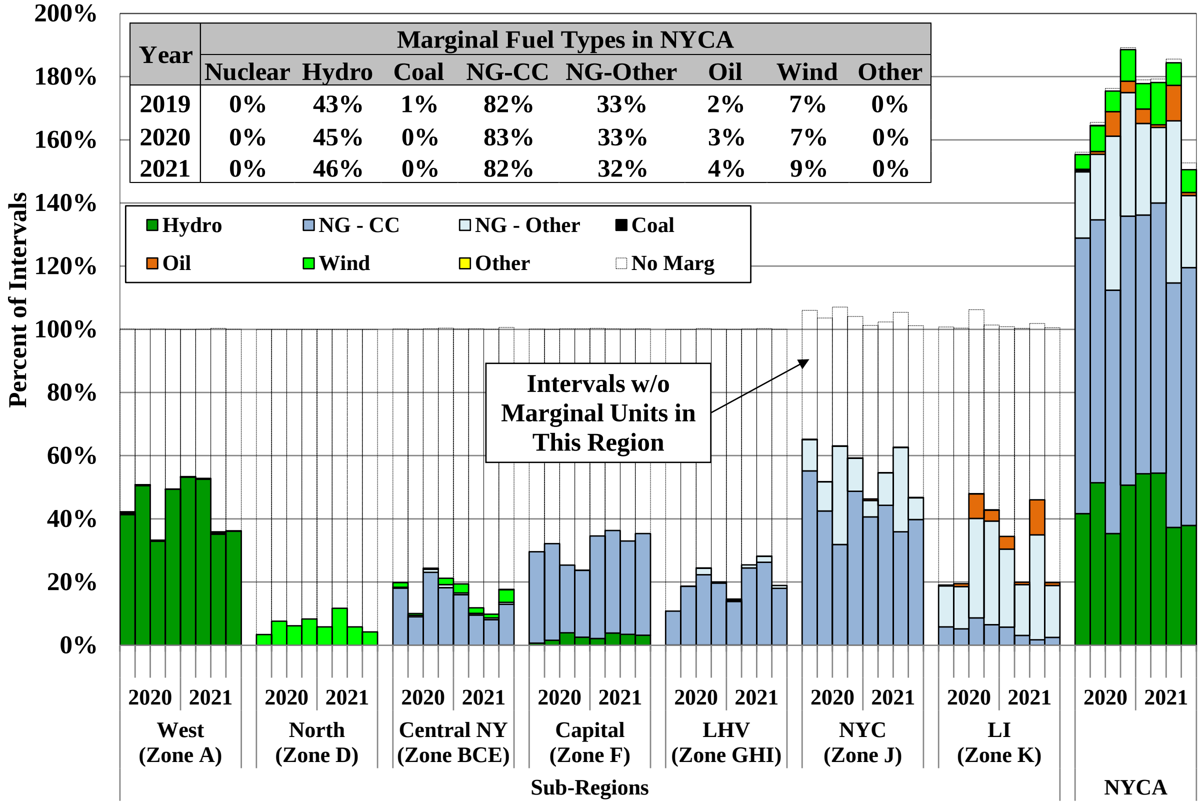


Year	Internal Generation by Fuel Type in NYCA (GW)								
	Nuclear	Hydro	Coal	NG-CC	NG-Other	Oil	Wind	Other	Total
2019	5.11	3.29	0.05	4.86	1.00	0.06	0.51	0.25	15.13
2020	4.37	3.21	0.02	5.23	1.18	0.04	0.51	0.26	14.81
2021	3.56	3.09	0.00	5.47	1.34	0.08	0.47	0.25	14.25

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 2021. More than one type of unit may be marginal in an interval, particularly when a transmission constraint is binding (different fuels may be marginal in the constrained and unconstrained areas). Hence, the total for all fuel types may be greater than 100 percent. For example, if hydro units and gas units were both on the margin in every interval, the total frequency shown in the figure would be 200 percent. When no unit is on the margin in a particular region, the LBMPs in that region are set by: (a) generators in other regions in the vast majority of intervals; or (b) shortage pricing of ancillary services or transmission constraints in a small share of intervals.

The fuel type for each generator in both charts is based on its actual fuel consumption reported to the U.S. Environmental Protection Agency ("EPA") and the U.S. Energy Information Administration ("EIA").

Figure A-8: Fuel Types of Marginal Units in the Real-Time Market in New York
By Quarter by Region, 2021



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:

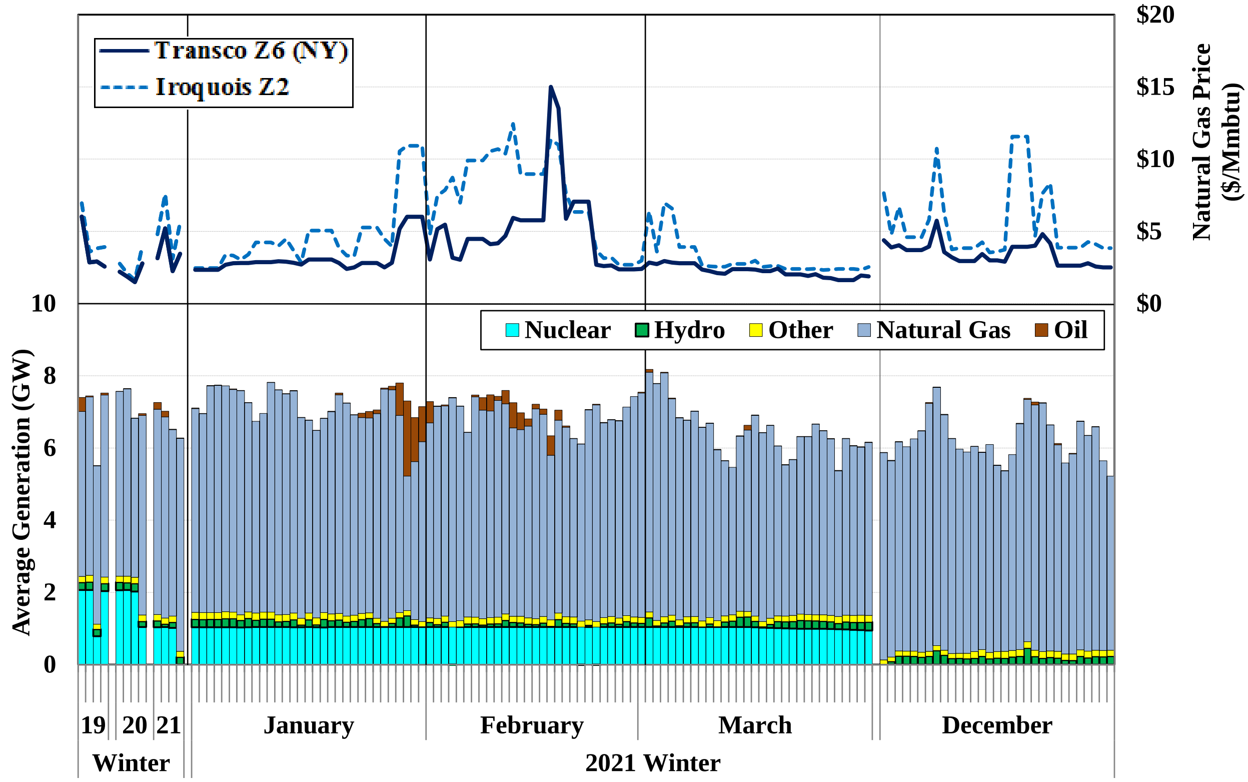
- Not having the necessary air permits;
- Not having oil-firing equipment in serviceable condition;
- Low on-site oil inventory;
- Physical limitations and gas scheduling timeframes that may limit the flexibility of dual-fueled units to switch from one fuel to the other; and
- NOx emissions limitations.

This subsection examines actual fuel usage in the winter of 2021, 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 2021 (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 2019 and 2021. 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, 2021



D. Emissions from Internal Generation

Power plants generate three main air pollutants when generating electricity: sulfur dioxide (SO_2), nitrogen oxides (NO_x), and carbon dioxide (CO_2). These emissions from electricity generation vary by type of fuel, energy technology, and power plant efficiency and have declined substantially since the inception of the NYISO markets. Policy makers have set up aggressive agenda in recent years for an ambitious clean energy transition from conventional energy resources. It is important for the NYISO markets to provide strong and clear incentives to attract new technologies and help integrate clean energy resources. This subsection examines the emission levels of the three major pollutants from internal generaion resources in the NYISO markets.

Figure A-10: Historical Emissions by Quarter in NYCA

Figure A-10 shows the historical trend of annual total emissions since 2000 in the NYISO footprint for CO_2, NO_x, and SO_2 by quarter.

Figure A-10: Historical Emissions of CO_2, NO_x, and SO_2 in NYCA
By quarter, 2000-2021

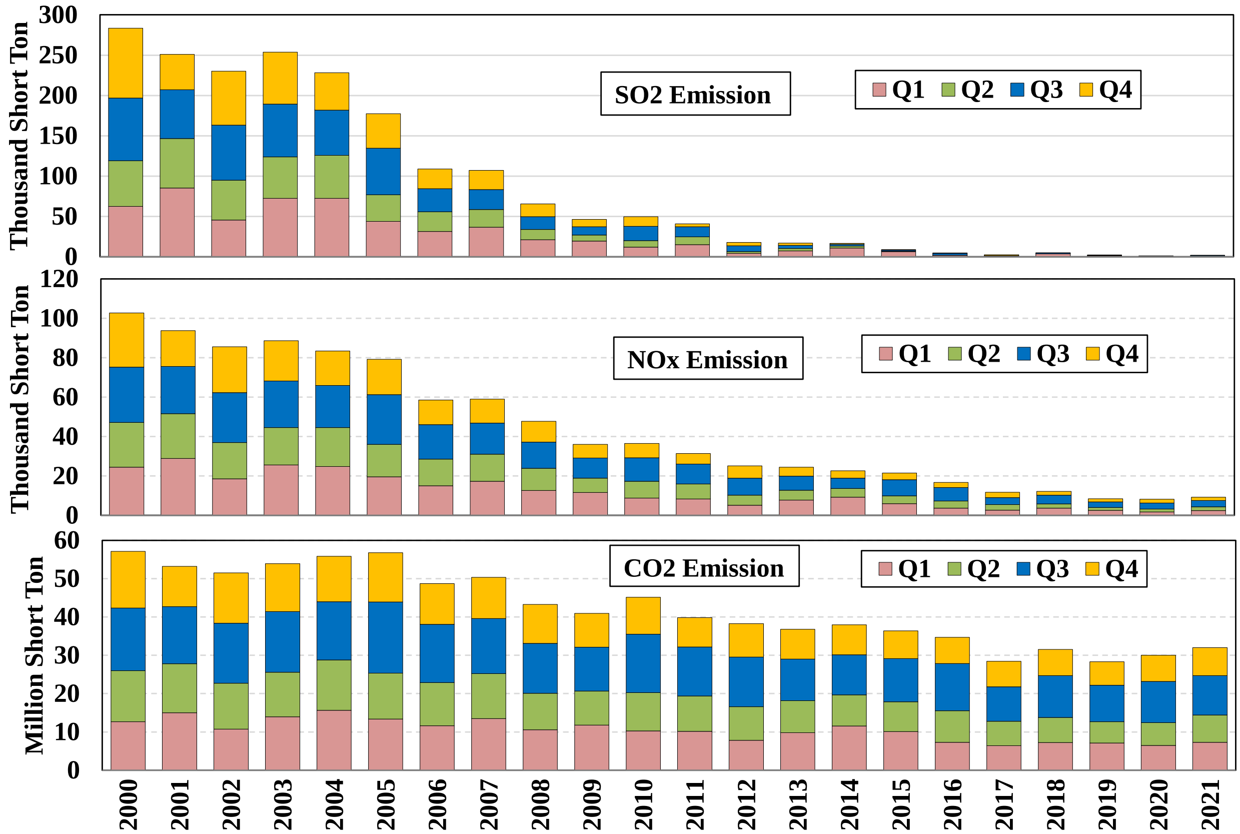


Figure A-11 - Figure A-13: Emissions by Region by Fuel Type

The following three figures show quarterly emissions across the system by generation fuel type for $CO_{2,}$ NOx, and $SO_{2,}$, respectively. Emission values are given for seven regions as well as the system as a whole for 2020 and 2021. The emission tonnage is given by aggregating the total pollution from operations on the various fossil fuel types for each month of the quarter. The inset tables in each chart provides summary data on the total tonnage of emissions by fuel type.

Figure A-11: CO_2 Emissions by Region by Fuel Type
by quarter, 2020-2021

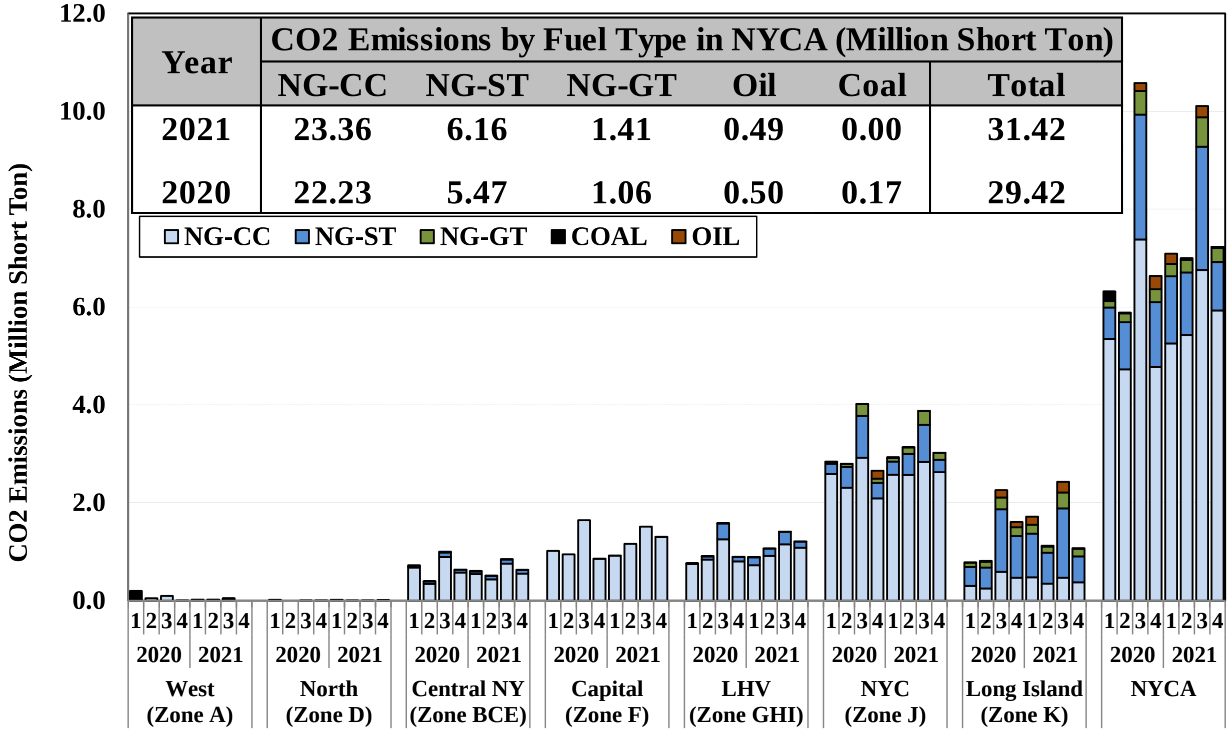


Figure A-12: NOx Emissions by Region by Fuel Type
by quarter, 2020-2021

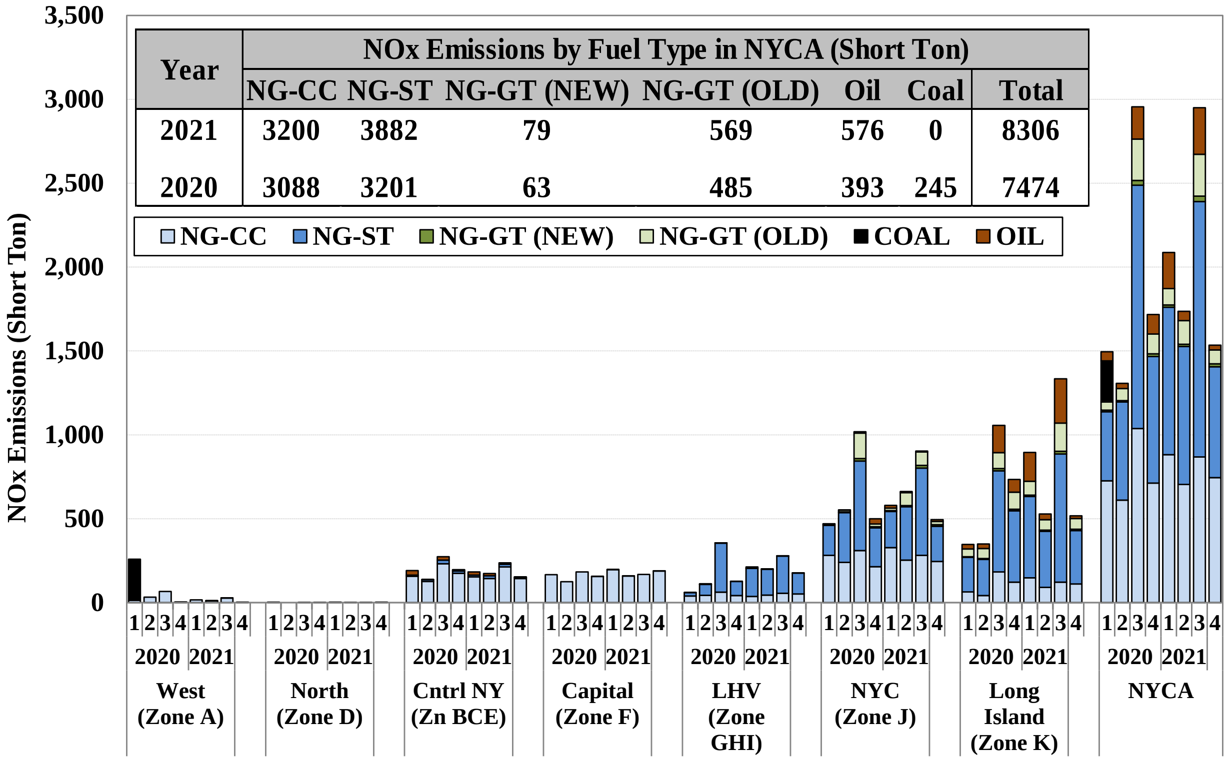
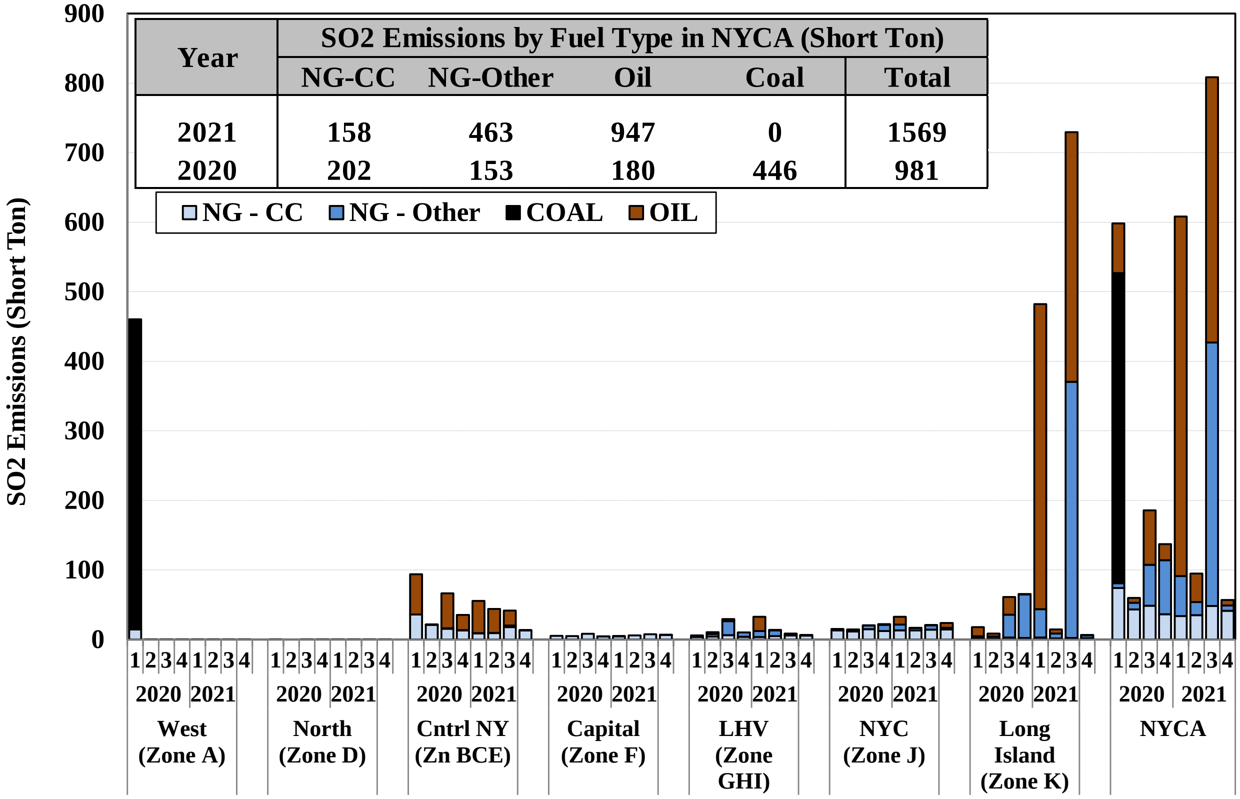


Figure A-13: SO_2 Emissions by Region by Fuel Type
by quarter, 2020-2021



Year	SO2 Emissions by Fuel Type in NYCA (Short Ton)				
	NG-CC	NG-Other	Oil	Coal	Total
2021	158	463	947	0	1569
2020	202	153	180	446	981

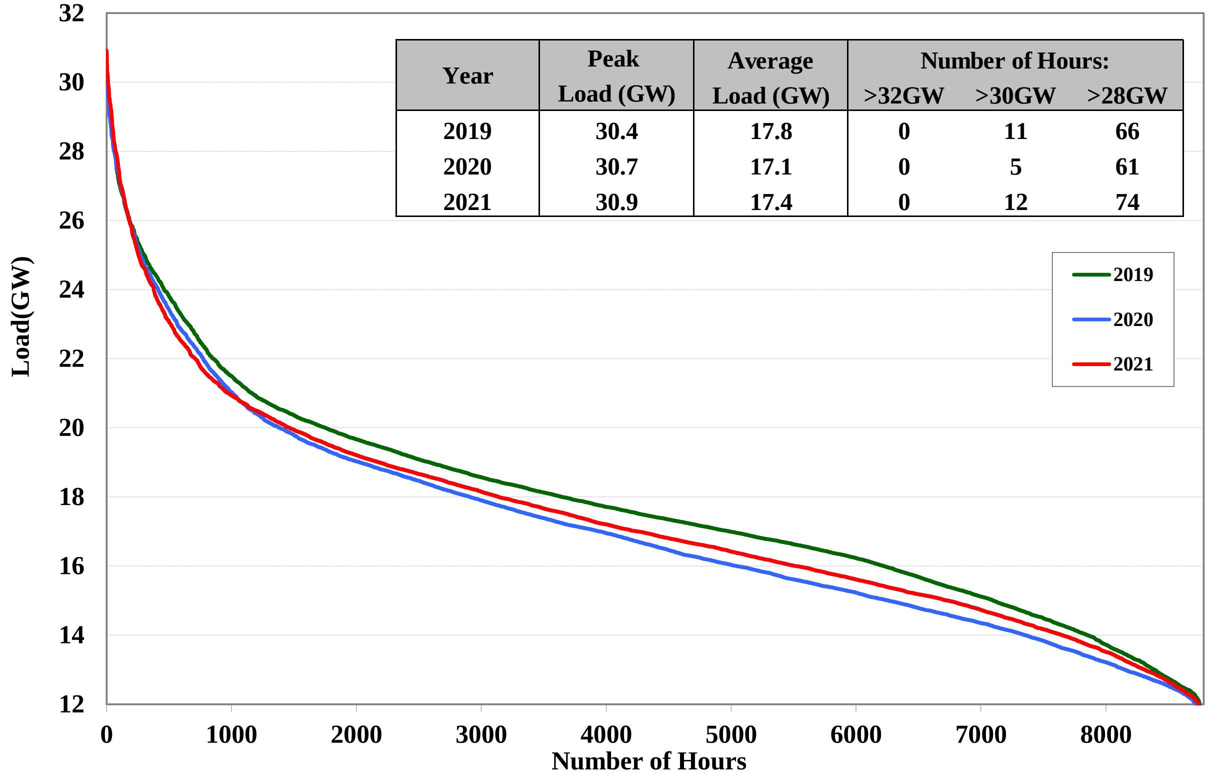
E. Load Levels

Figure A-14: 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-14 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-14: Load Duration Curves for New York State
2019 – 2021



Year	Peak Load (GW)	Average Load (GW)	Number of Hours: >32GW	>30GW	>28GW
2019	30.4	17.8	0	11	66
2020	30.7	17.1	0	5	61
2021	30.9	17.4	0	12	74

F. Day-Ahead Ancillary Services Prices

Figure A-15: 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-15 shows the average day-ahead prices for these four ancillary services products in each month of 2020 and 2021. The prices are shown separately for the following four distinct regions: (a) New York City, (b) Southeast New York (including Zones G-I and Zone K); (b) the Capital Zone (Zone F, in Eastern New York but outside Southeast New York); and (c) West New York (including Zones A-E).

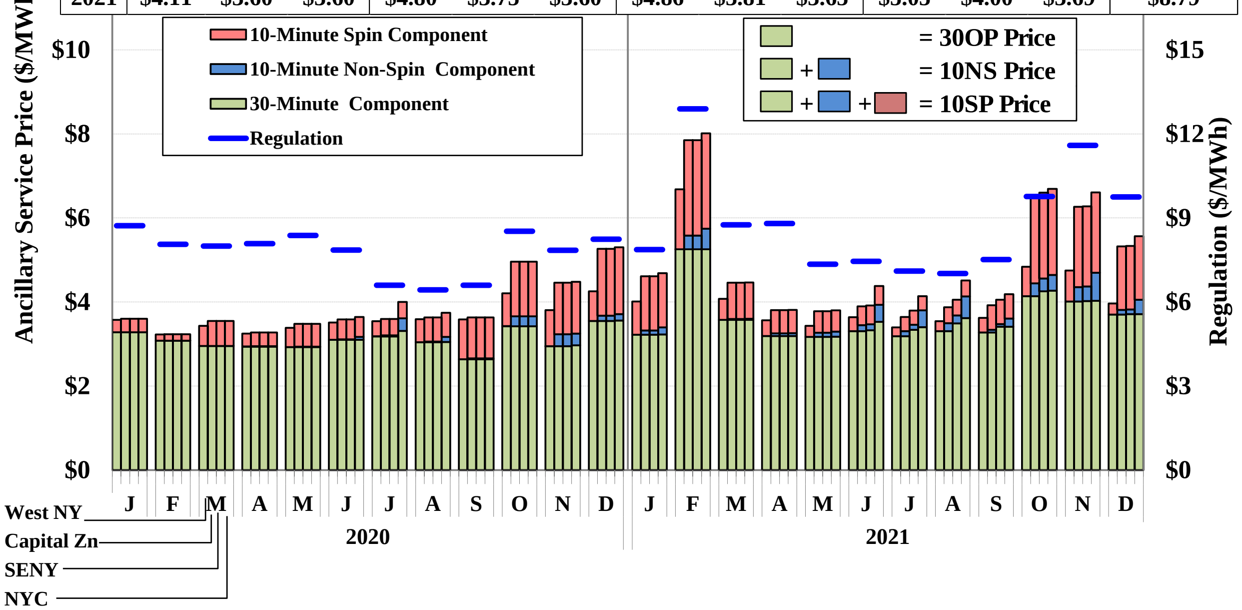
The stacked bars show three price components for each region: the 10-minute spinning component, the 10-minute non-spin component, and the 30-minute component, each representing the cost of meeting applicable underlying reserve requirements. Take New York City as an example:

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

Therefore, in the figure, the 30-minute reserve price in each region equals its 30-minute component, the 10-minute non-spin reserve price equals the sum of its 30-minute component and 10-minute non-spin component, and the 10-minute spinning reserve price equals the sum of all three price components. The inset table compares average final prices (not the components) in 2020 and 2021 on an annual basis.

Figure A-15: Day-Ahead Ancillary Services Prices
2020- 2021

	West NY			Capital Zone			Southeast NY			New York City			Regulation
Year	10SP	10NS	30OP	10SP	10NS	30OP	10SP	10NS	30OP	10SP	10NS	30OP	
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
2021	$4.11	$3.60	$3.60	$4.80	$3.75	$3.60	$4.86	$3.81	$3.65	$5.05	$4.00	$3.69	$8.79



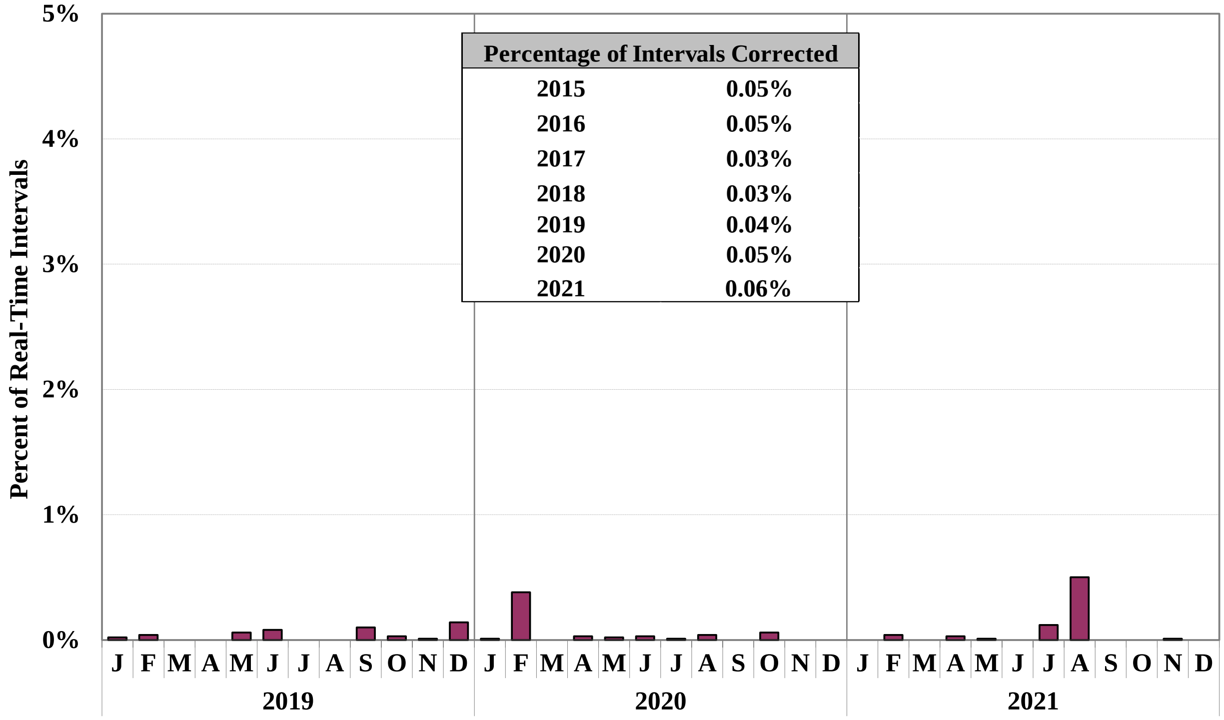
G. Price Corrections

Figure A-16: 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-16 summarizes the frequency of price corrections in the real-time energy market in each month from 2019 to 2021. 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-16: Frequency of Real-Time Price Corrections
2019-2021



H. 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.

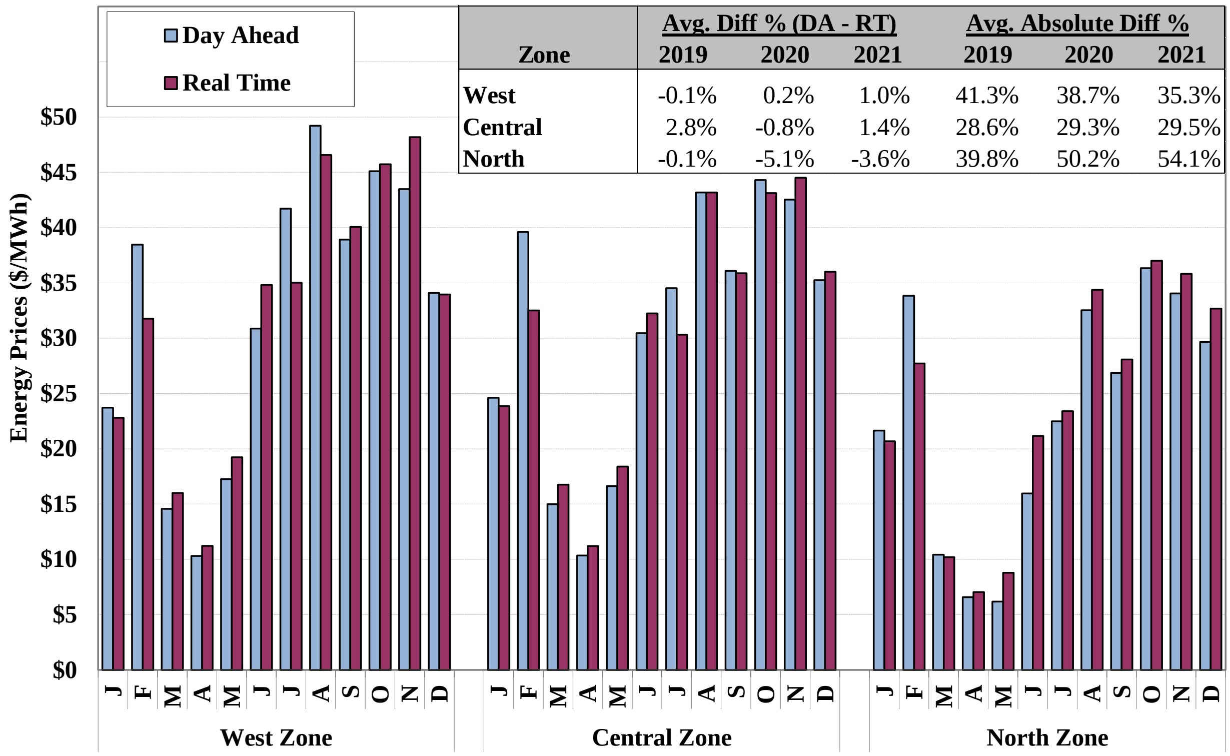
Figure A-17 & Figure A-18: Average Day-Ahead and Real-Time Energy Prices

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-17 and Figure A-18 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-17: Average Day-Ahead and Real-Time Energy Prices in Western New York

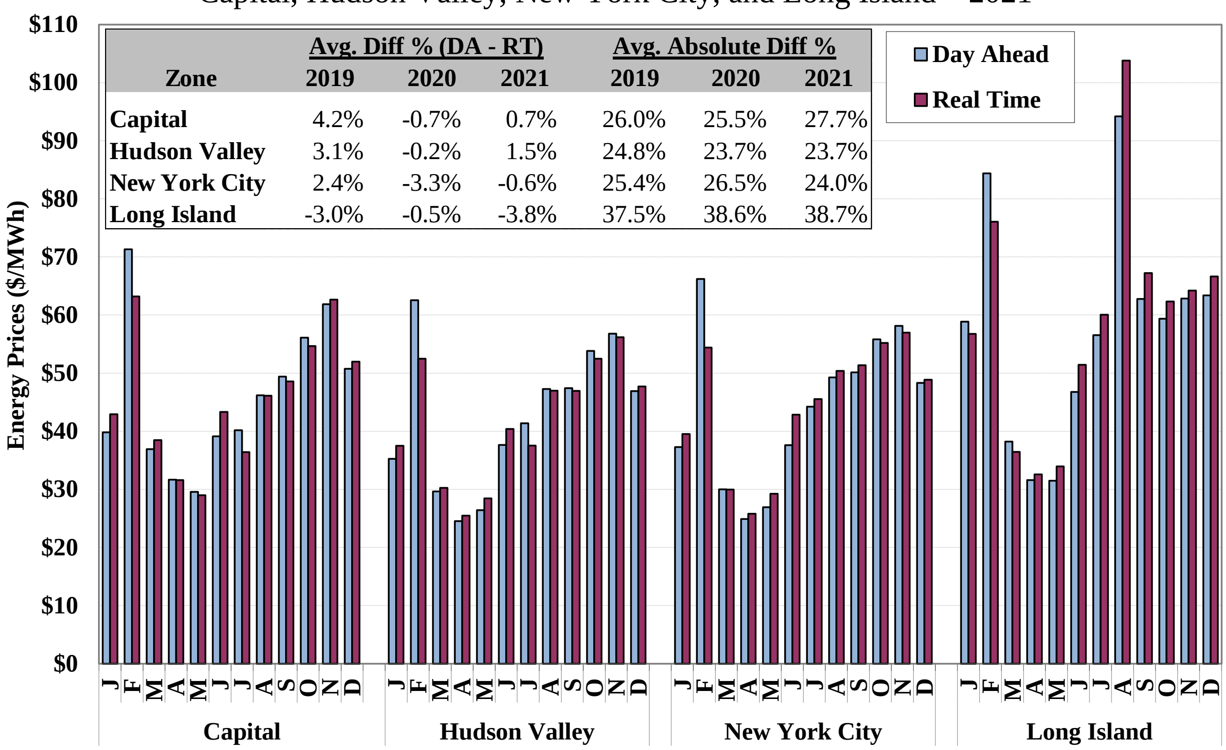
West, Central, and North Zones – 2021



Zone	Avg. Diff % (DA - RT) 2019	2020	2021	Avg. Absolute Diff % 2019	2020	2021
West	-0.1%	0.2%	1.0%	41.3%	38.7%	35.3%
Central	2.8%	-0.8%	1.4%	28.6%	29.3%	29.5%
North	-0.1%	-5.1%	-3.6%	39.8%	50.2%	54.1%

Figure A-18: Average Day-Ahead and Real-Time Energy Prices in Eastern New York

Capital, Hudson Valley, New York City, and Long Island – 2021



Zone	Avg. Diff % (DA - RT) 2019	2020	2021	Avg. Absolute Diff % 2019	2020	2021
Capital	4.2%	-0.7%	0.7%	26.0%	25.5%	27.7%
Hudson Valley	3.1%	-0.2%	1.5%	24.8%	23.7%	23.7%
New York City	2.4%	-3.3%	-0.6%	25.4%	26.5%	24.0%
Long Island	-3.0%	-0.5%	-3.8%	37.5%	38.6%	38.7%

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.

I. 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-19 to Figure A-25: 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-19 shows that the day-ahead Western 30-minute reserve prices for approximately 85 percent of hours had a day-ahead premium of $5.00/MWh or less, in 2021 including intervals where the day-ahead premium was negative (i.e. real-time prices exceeded day-ahead prices).

The figures compare the distributions between 2020 and 2021. 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 $2.50 and $5.00/MWh for 70 percent of the hours in 2021 (between $2.75 and $3.75/MWh in 2020). The inset tables summarize the following annual averages in 2020 and 2021: (a) the average day-ahead price; (b) the average real-time price; (c) the difference between the average day-ahead price and the real-time price; and (d) the average absolute difference between the day-ahead price and the real-time price.

Figure A-19: Day-Ahead Premiums for 30-Minute Reserves in West New York

2020 – 2021

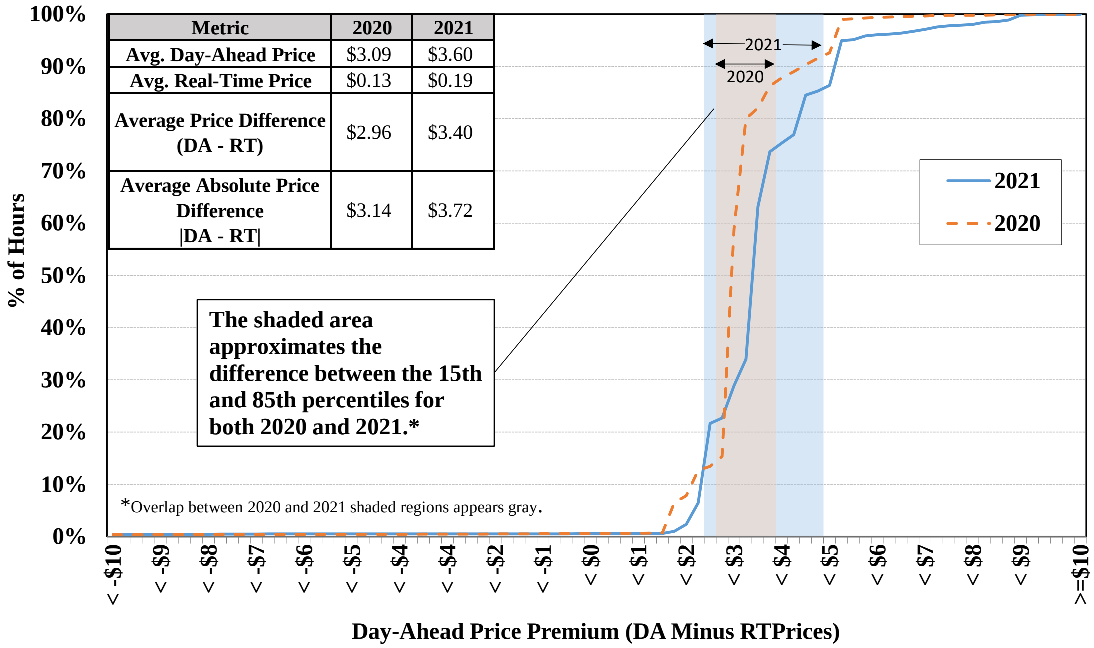


Figure A-20: Day-Ahead Premiums for 10-Minute Spinning Reserves in West New York
2020 – 2021

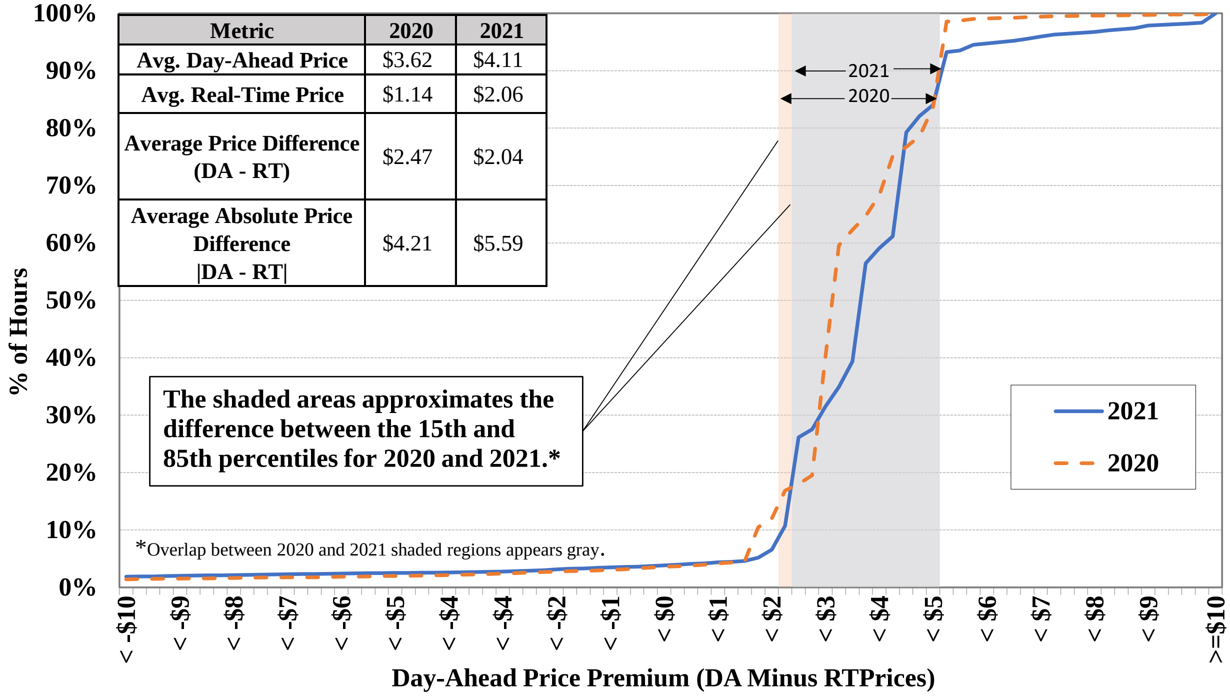


Figure A-21: Day-Ahead Premiums for 10-Minute Spinning Reserves in East New York
2020 – 2021

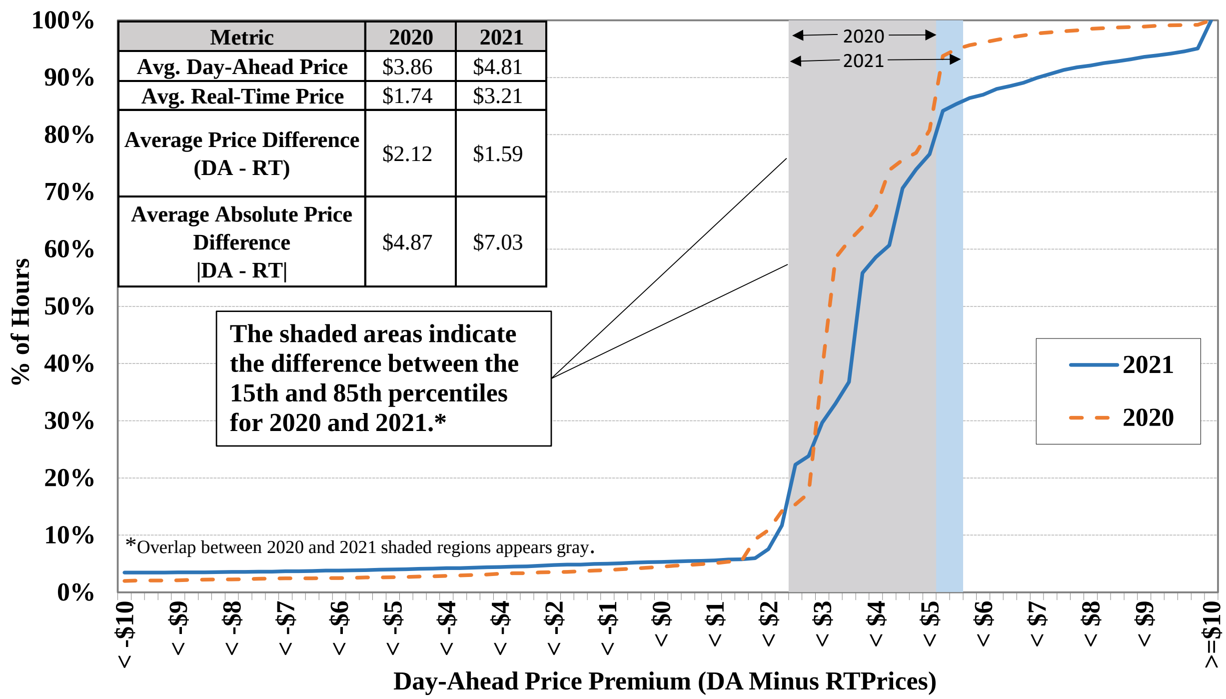
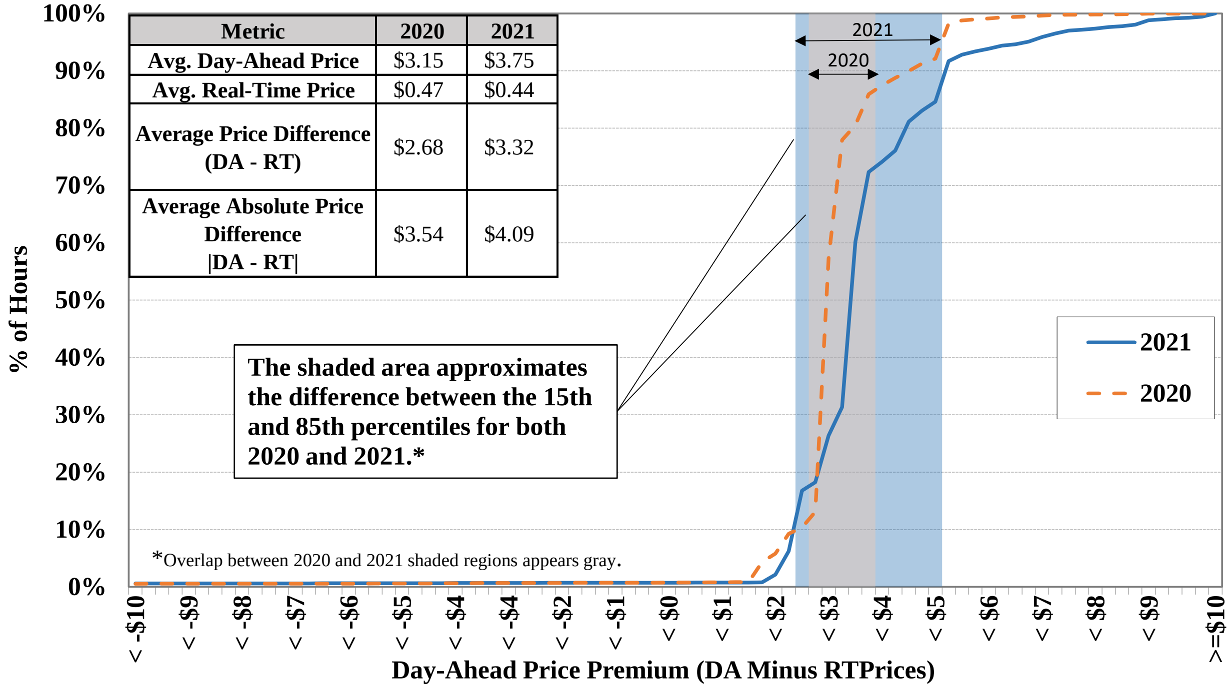
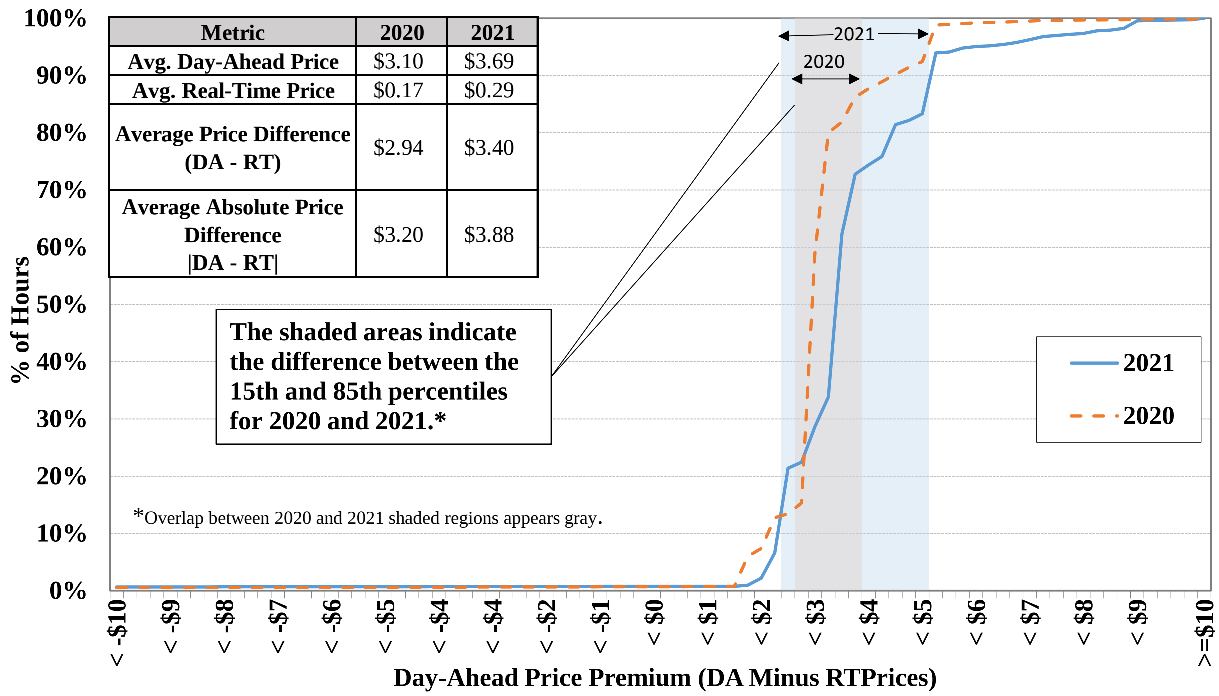


Figure A-22: Day-Ahead Premiums for 10-Minute Non-Spin Reserves in East New York
2020 – 2021



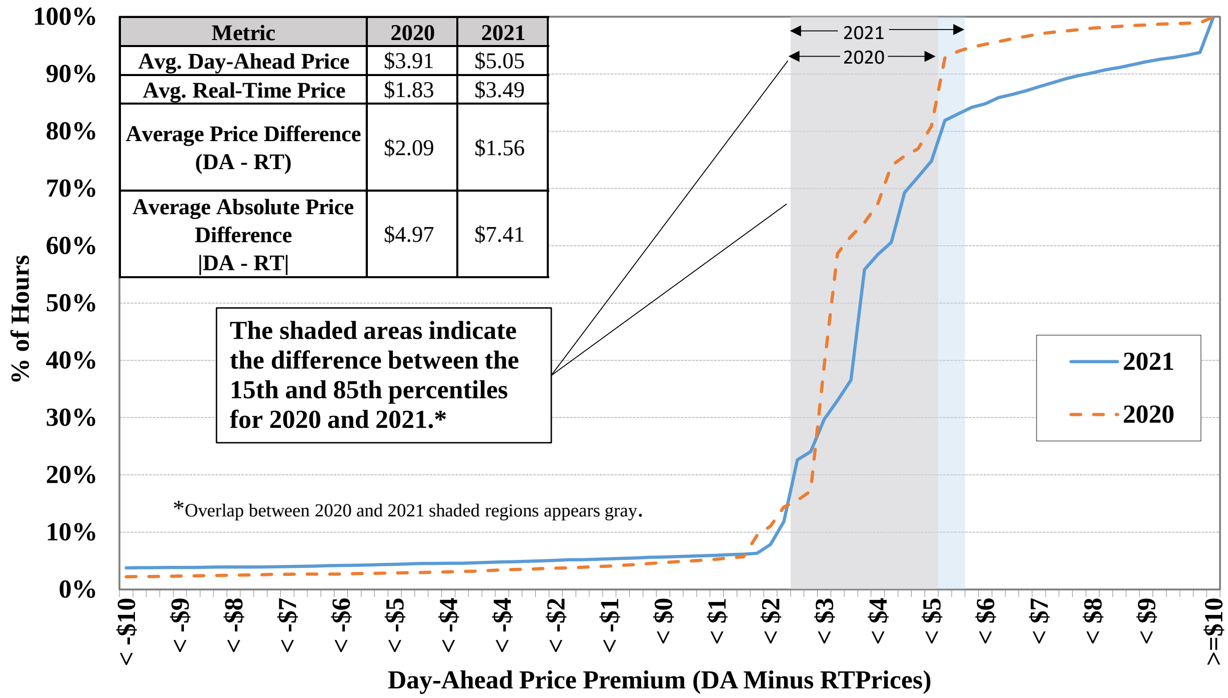
Metric	2020	2021
Avg. Day-Ahead Price	$3.15	$3.75
Avg. Real-Time Price	$0.47	$0.44
Average Price Difference (DA - RT)	$2.68	$3.32
Average Absolute Price Difference |DA - RT|	$3.54	$4.09

Figure A-23: Day-Ahead Premiums for 30-Minute Reserves in New York City
2020 – 2021



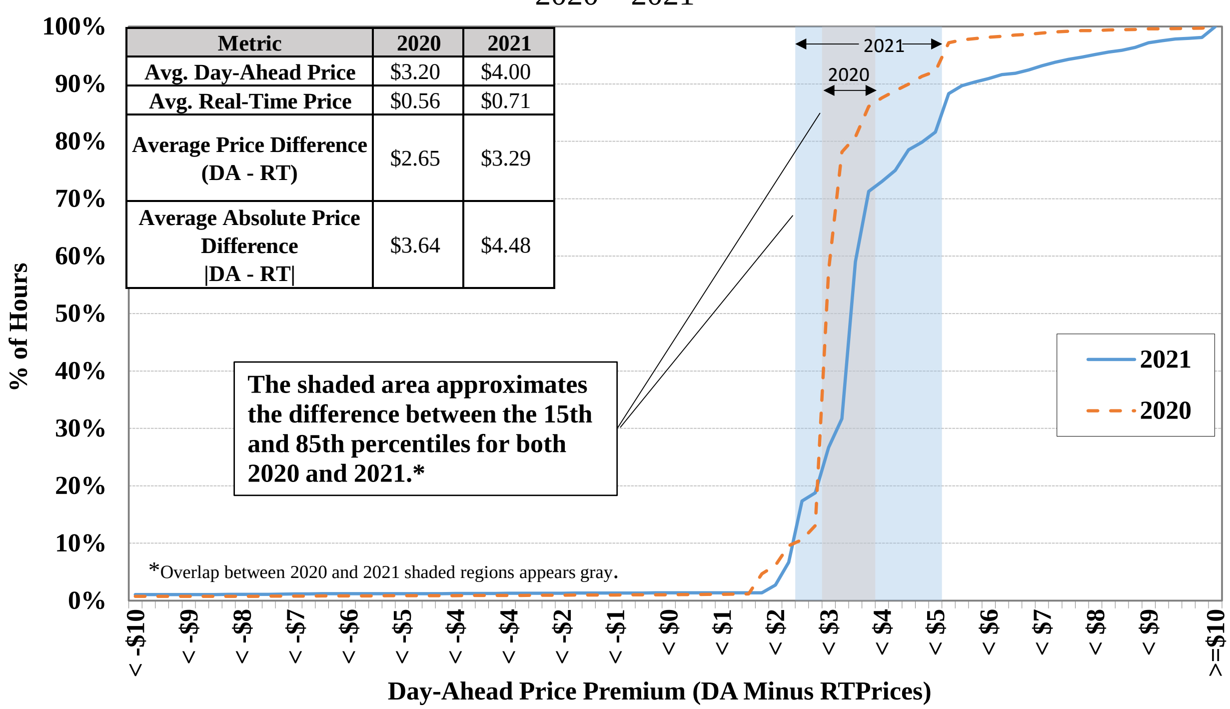
Metric	2020	2021
Avg. Day-Ahead Price	$3.10	$3.69
Avg. Real-Time Price	$0.17	$0.29
Average Price Difference (DA - RT)	$2.94	$3.40
Average Absolute Price Difference |DA - RT|	$3.20	$3.88

Figure A-24: Day-Ahead Premiums for 10-Minute Spinning Reserves in New York City
2020 - 2021



Metric	2020	2021
Avg. Day-Ahead Price	$3.91	$5.05
Avg. Real-Time Price	$1.83	$3.49
Average Price Difference (DA - RT)	$2.09	$1.56
Average Absolute Price Difference |DA - RT|	$4.97	$7.41

Figure A-25: Day-Ahead Premiums for 10-Minute Non-Spin Reserves in New York City
2020 – 2021



Metric	2020	2021
Avg. Day-Ahead Price	$3.20	$4.00
Avg. Real-Time Price	$0.56	$0.71
Average Price Difference (DA - RT)	$2.65	$3.29
Average Absolute Price Difference |DA - RT|	$3.64	$4.48

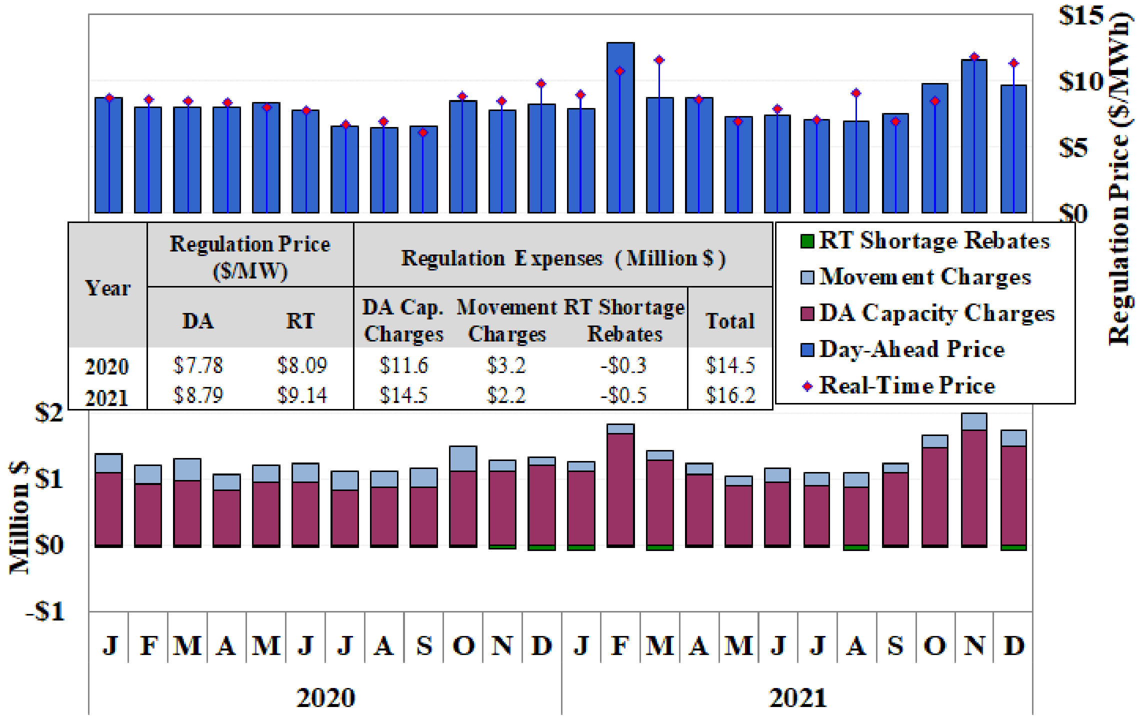
J. Regulation Market Performance

Figure A-26 – Regulation Prices and Expenses

Figure A-26 shows the regulation prices and expenses in each month of 2020 and 2021. The upper portion of the figure compares the regulation prices in the day-ahead and real-time markets.[255] 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-26: Regulation Prices and Expenses
by Month, 2020 – 2021



Year	Regulation Price ($/MW)		Regulation Expenses (Million $)			
	DA	RT	DA Cap. Charges	Movement Charges	RT Shortage Rebates	Total
2020	$7.78	$8.09	$11.6	$3.2	-$0.3	$14.5
2021	$8.79	$9.14	$14.5	$2.2	-$0.5	$16.2

255 The day-ahead regulation price shown in the upper portion of the chart is a composite value of the capacity price and a movement component.

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 during the peak winter periods 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. Alternatively, 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.* [256]

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.

[256] 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.

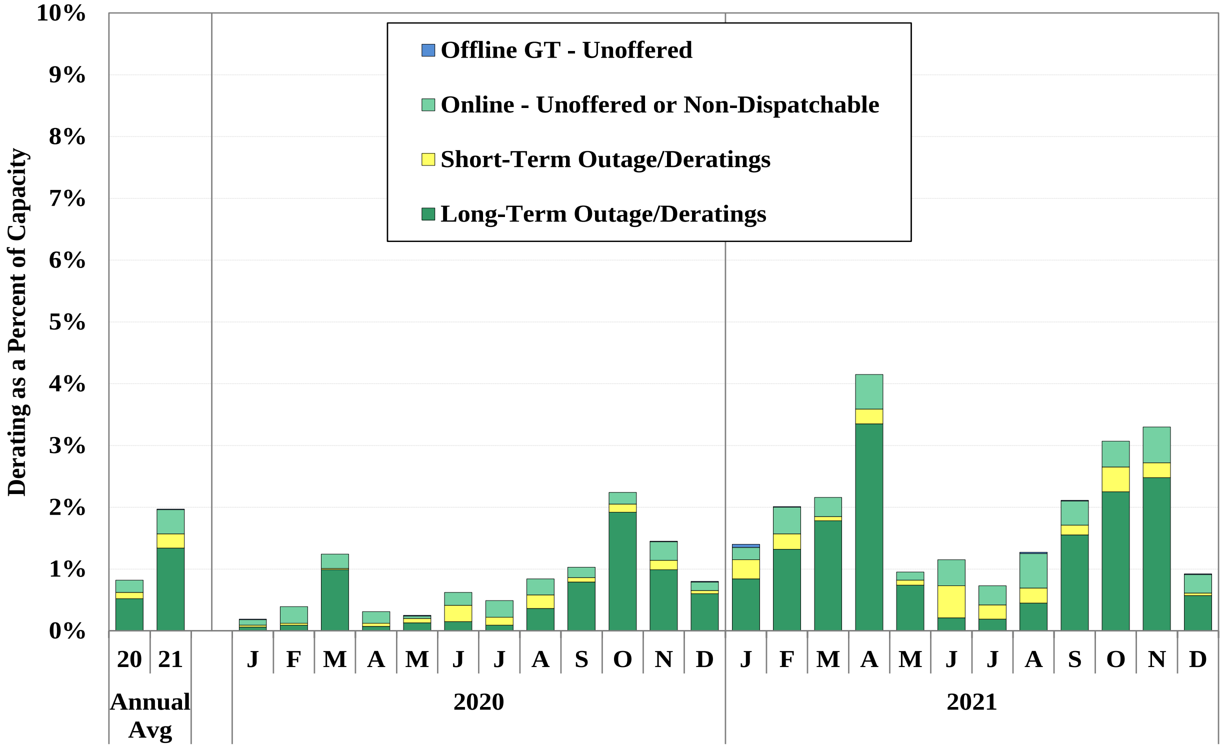
We also focus on economic capacity, since derated and unoffered capacity that is uneconomic does not raise prices above competitive levels and, therefore, is not an indicator of potential withholding.

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.[257] 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.[258] Quick-start units that were economic to commit must have been economic at both forecast RTC prices and settlement RTD prices.[259]

Figure A-27 - Figure A-28: Unoffered Economic Capacity by Month

Figure A-27 and Figure A-28 show the broad patterns of deratings and real-time unoffered capacity in New York State and Eastern New York in each month of 2020 and 2021.

Figure A-27: Unoffered Economic Capacity by Month in NYCA
2020 – 2021



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

258 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.

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

Figure A-28: Unoffered Economic Capacity by Month in East New York
2020 - 2021

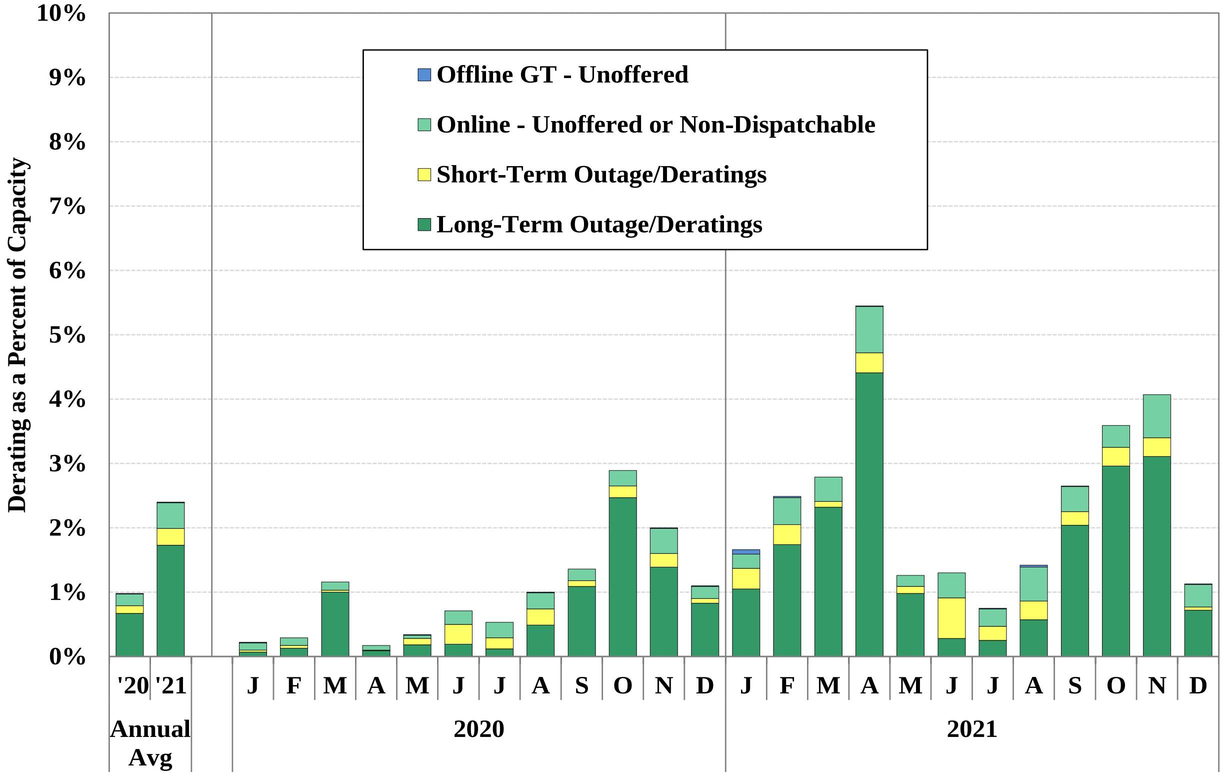


Figure A-29 & Figure A-30: Unoffered Economic Capacity by Load Level & Portfolio Size

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-29: Unoffered Economic Capacity by Supplier by Load Level in New York
2020 – 2021

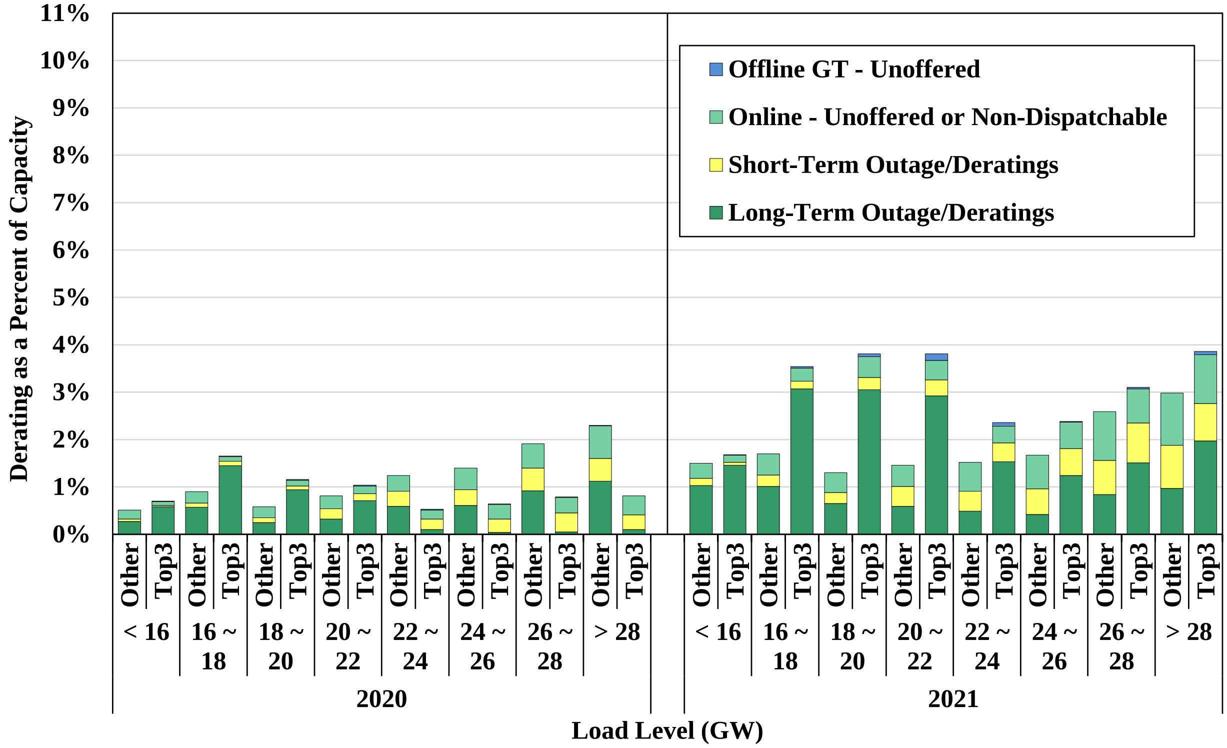
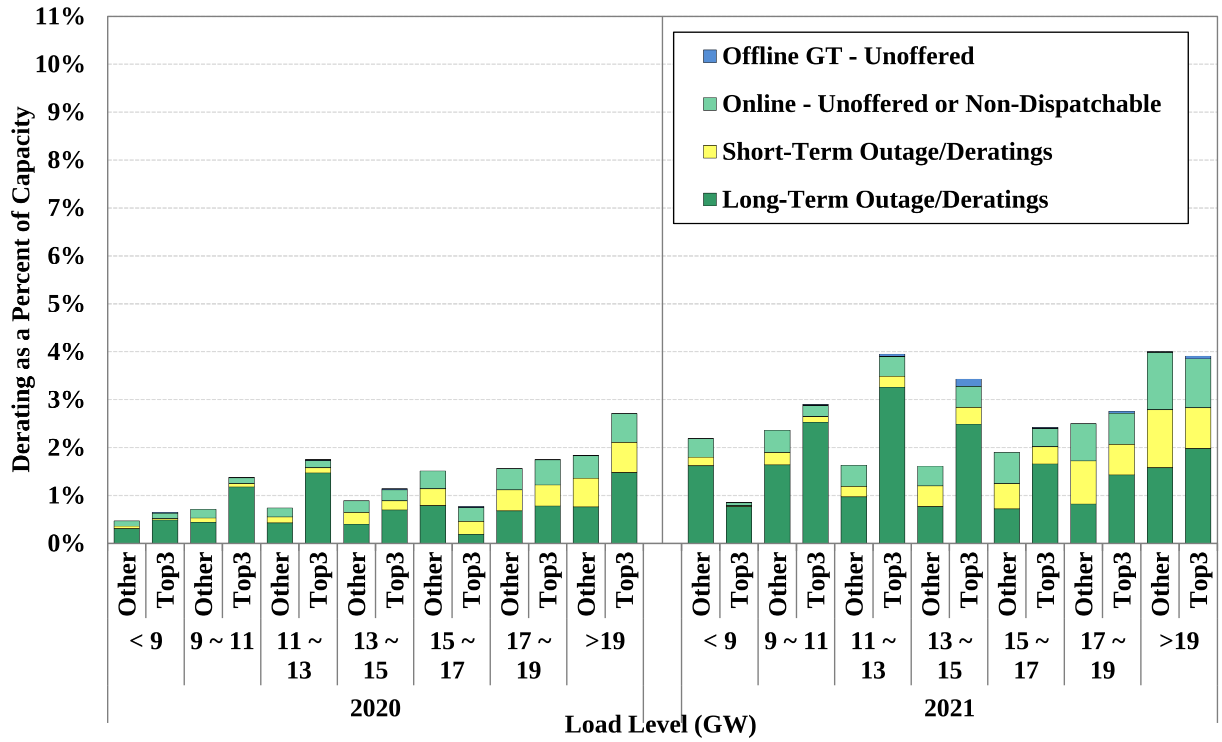


Figure A-30: Unoffered Economic Capacity by Supplier by Load Level in East New York
2020 – 2021



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-29 and Figure A-30 to determine whether the conduct is consistent with workable competition.

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.[260, 261] An offer parameter is generally considered to be above the competitive level if it exceeds the reference level by a given threshold.

Figure A-31 to Figure A-34: 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 the owner's elevated offer.[262] We assume that the unit's competitive offer price is equal to its reference level. To determine whether a unit is economic, we evaluate whether it would have been economic to commit based on day-ahead prices and whether its incremental energy would have been economic to produce based on real-time prices. Since gas turbines can be started in real-time, they are evaluated based on real-time prices. Like the prior analysis of potential physical withholding, we examine the broad patterns of output gap in New York State and Eastern New York, and we address the relationship of the output gap to the market demand level and participant size.

The following four figures show the output gap using three thresholds: the state-wide mitigation threshold (i.e., the standard conduct threshold used for mitigation outside New York City), which is the lower of $100 per MWh or 300 percent of a generator's reference level; and two additional lower thresholds: Lower Threshold 1 is 25 percent of a generator's reference level, and Lower Threshold 2 is 100 percent of a generator's reference level. The two lower thresholds are

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260 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.

261 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.

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

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

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-31: Output Gap by Month in New York State
2020 – 2021

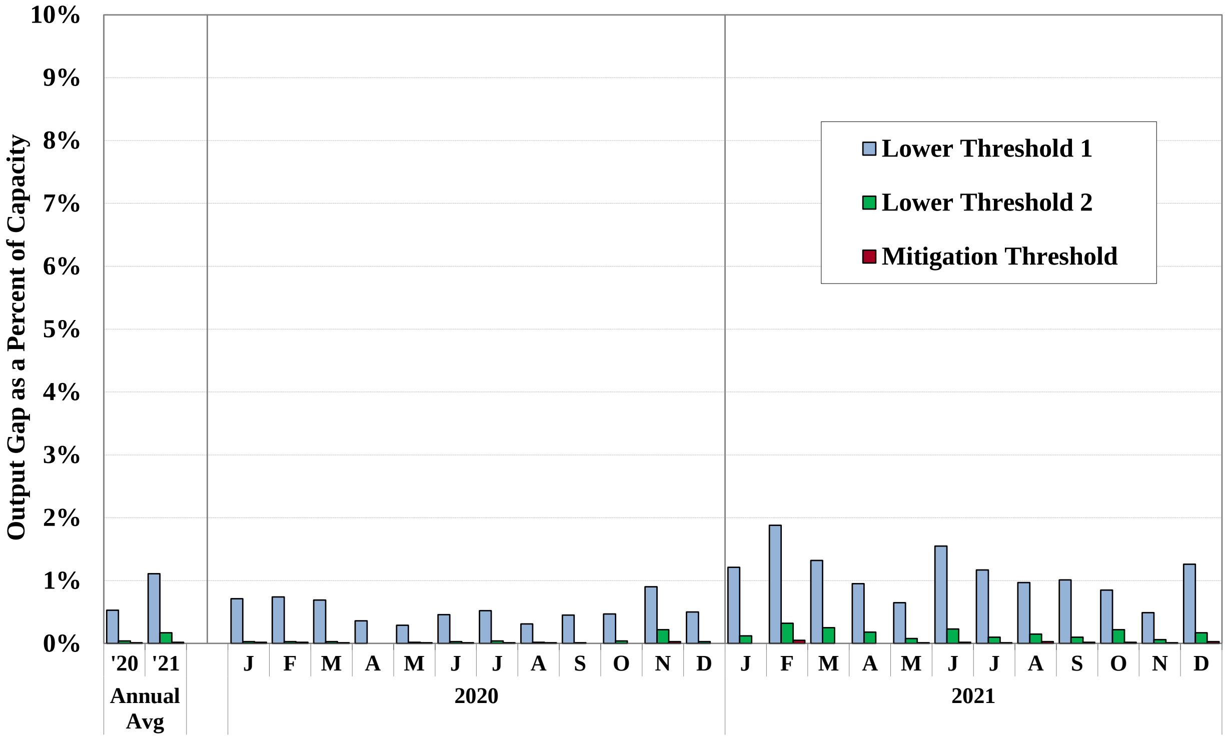


Figure A-32: Output Gap by Month in East New York
2020 - 2021

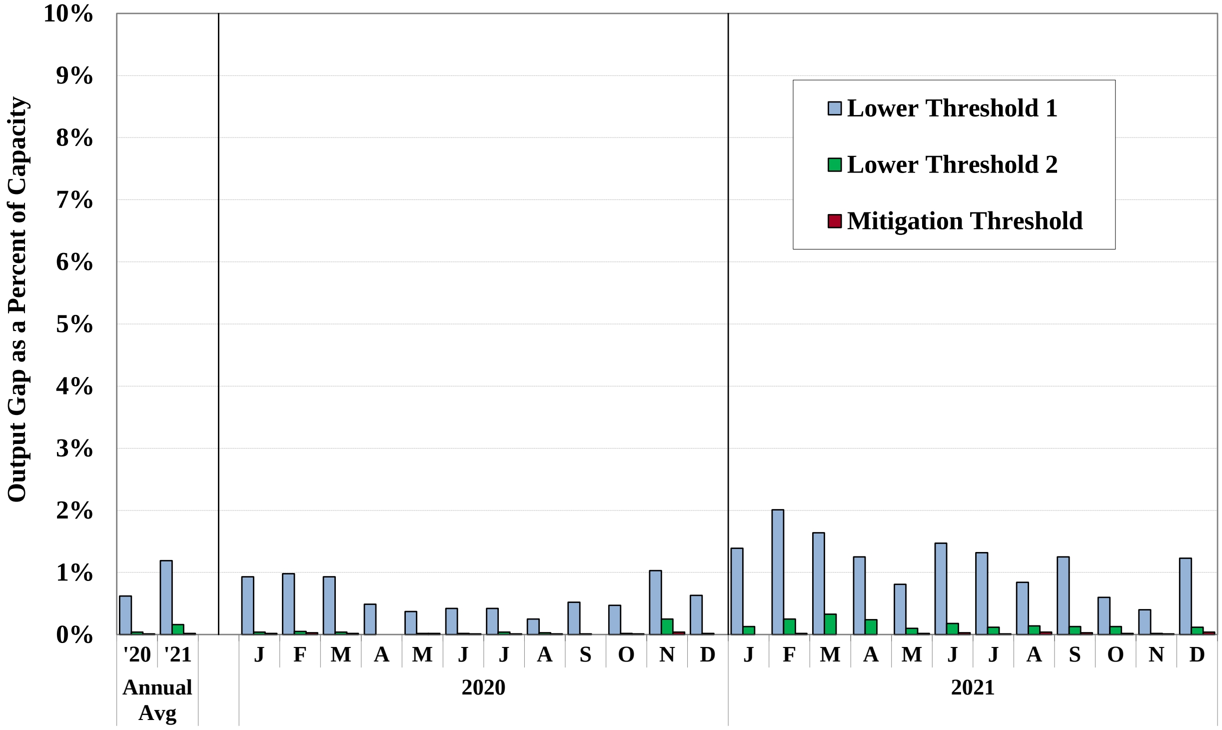


Figure A-33: Output Gap by Supplier by Load Level in New York State
2021

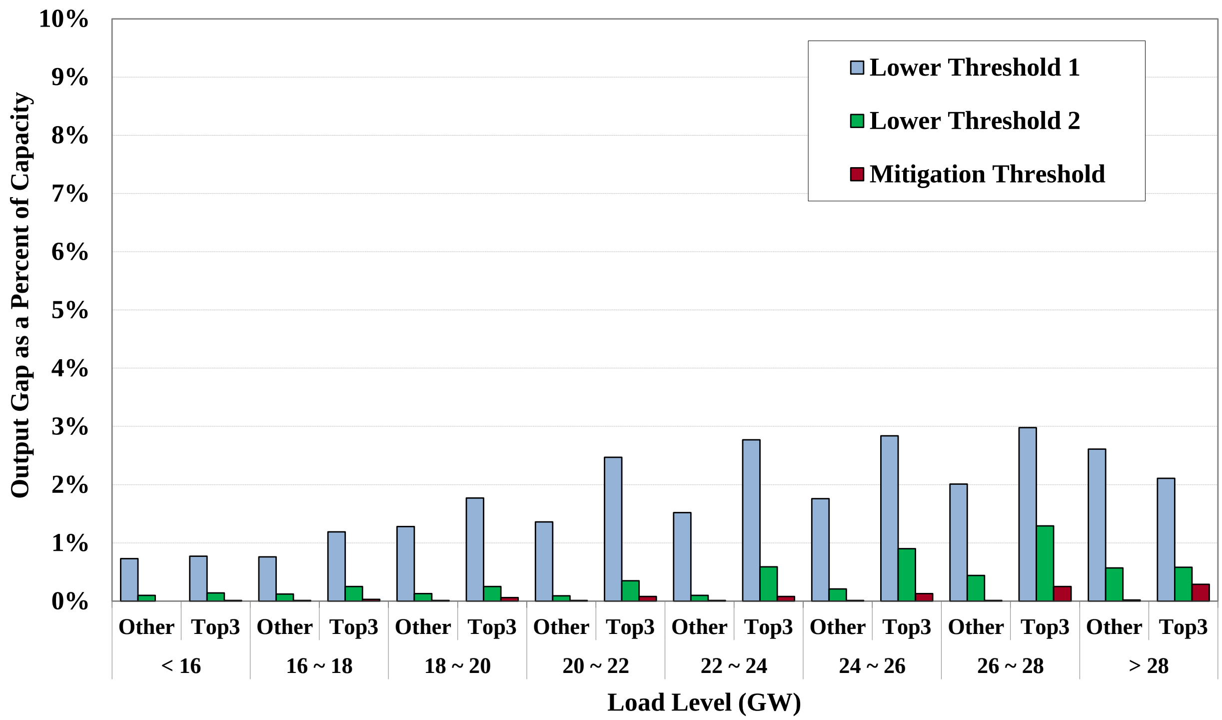
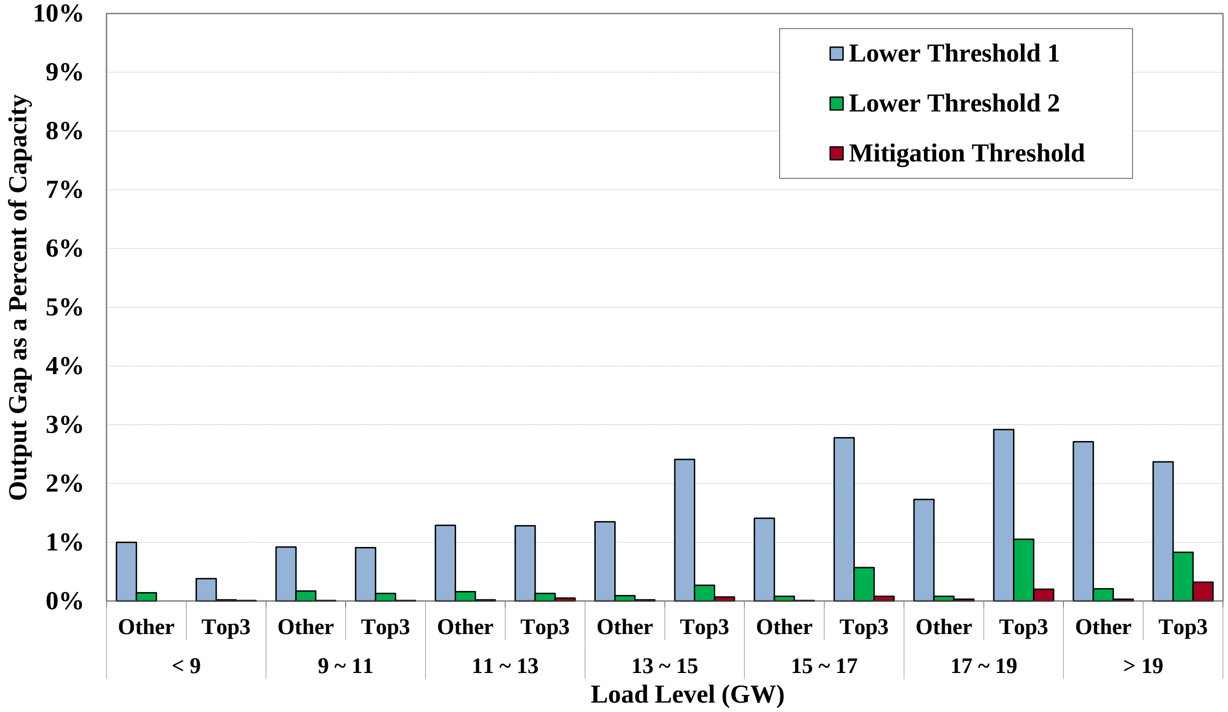


Figure A-34: Output Gap by Supplier by Load Level in East New York
2021



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.[263] 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

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

preceding twelve-month period.[264] 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.[265] 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.[266]

While uncommon, a generator can be mitigated initially in the day-ahead or real-time market and unmitigated after consultation with the NYISO.[267] 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.[268]
- 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.

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264 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.

265 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.

266 See NYISO Market Services Tariff, Section 23.3.1.2.3.

267 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.

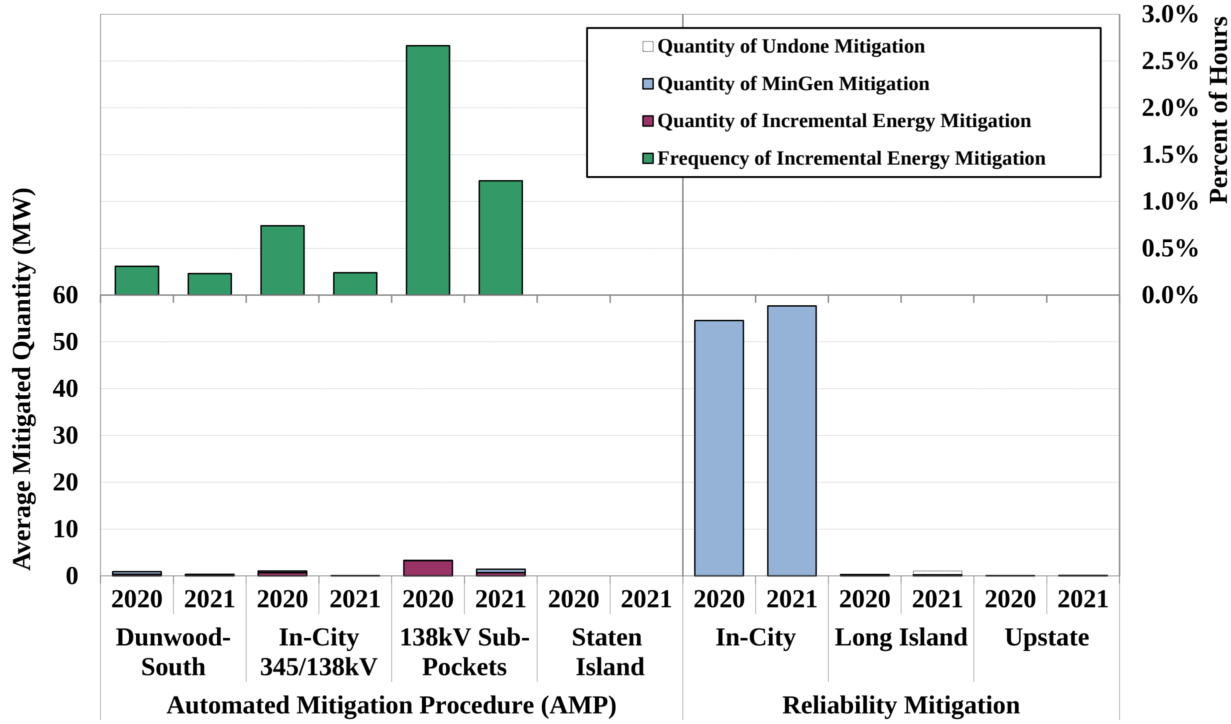
268 The hierarchy of information that is used to calculate reference levels is provided in NYISO Market Services Tariff, Section 23.3.1.4. It is possible for a generator to have a bid-based or LBMP-based reference level that is less accurate than the reference level determined through consultation.

Figure A-35 & Figure A-36: Summary of Day-Ahead and Real-Time Mitigation

Figure A-35 and Figure A-36 summarize the amount of mitigation in New York that occurred in the day-ahead and the real-time markets in 2020 and 2021. These figures do not include guarantee payment mitigation that occurs in the settlement system.

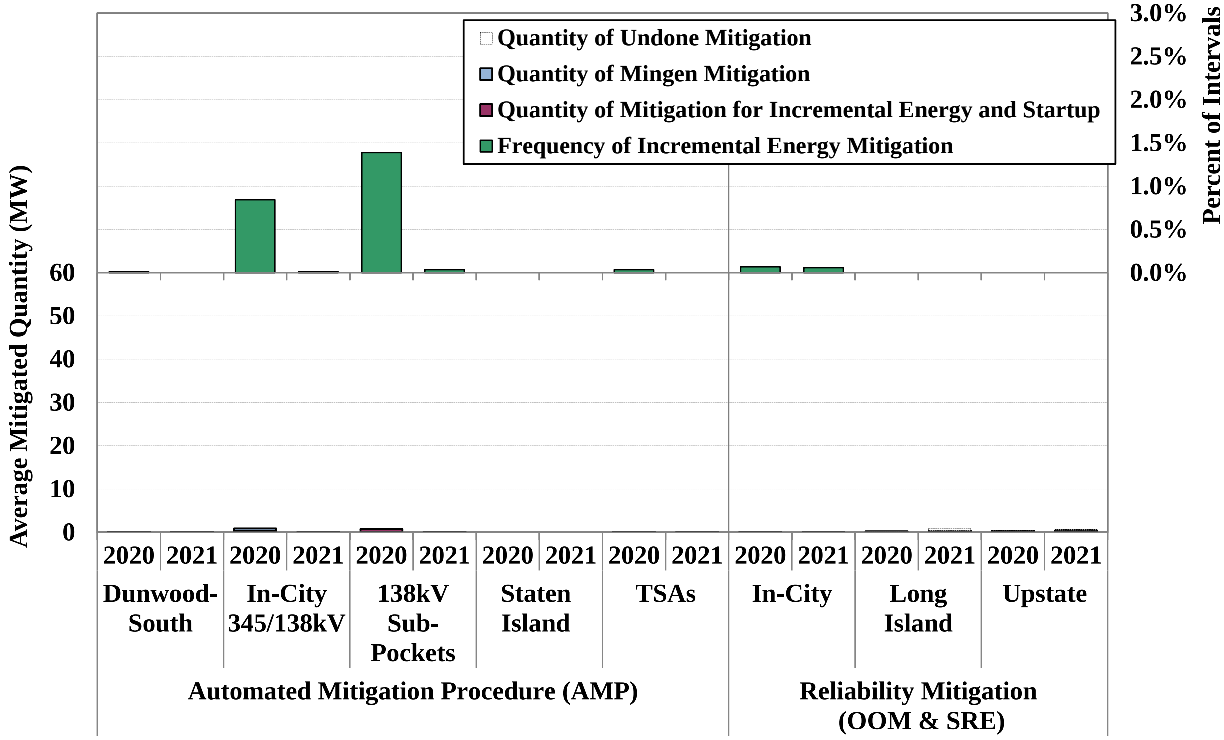
The bars in the upper panel of the figures indicate the percent of hours when incremental energy offer mitigation was imposed on one or more units in each category, while the bars in the lower panel indicate the average amount of capacity mitigated in hours when mitigation occurred (as well as the portion 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).[269] In each figure, the left portion shows the amount of mitigation by the Automated Mitigation Procedure ("AMP") on the economically committed units in load pockets of New York City, and the right portion shows the amount of mitigation on the units committed for reliability in New York City, Long Island, and the upstate area.

Figure A-35: Summary of Day-Ahead Mitigation
2020 – 2021



269 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-36: Summary of Real-Time Mitigation
2020 – 2021



D. Ancillary Services Offers in the Day-Ahead Market

Multiple factors, including opportunity costs, demand curves, and offers, determine the prices of ancillary services. The NYISO co-optimizes the scheduling of energy and ancillary services in the day-ahead and real-time markets. Co-optimization causes the prices of energy and ancillary services to reflect the costs to the system of diverting resources to provide ancillary services that would otherwise provide energy.

The ancillary services markets use demand curves that represent the economic value placed on each class of reserves. When the reserve requirements cannot be satisfied at a cost lower than the demand curve, the system is in a shortage and the reserve demand curve value is included in the reserve price and the energy price. This approach is recognized for producing efficient prices during shortages of reserves because it provides a mechanism for reflecting the value of reserves in the price of energy during shortages.

This subsection focuses on ancillary services offer patterns in the day-ahead market. In an efficient market, we expect suppliers to respond to predictable differences between day-ahead and real-time prices by raising or lowering their offer prices in the day-ahead market. However, the high volatility of real-time clearing prices is difficult to predict in the day-ahead market. High volatility of real-time prices is a source of risk for suppliers that sell reserves in the day-ahead market, since suppliers must forego real-time scarcity revenues if they have already sold reserves in the day-ahead market. Some suppliers may reduce their exposure to this risk by raising their reserves offer prices in the day-ahead market.

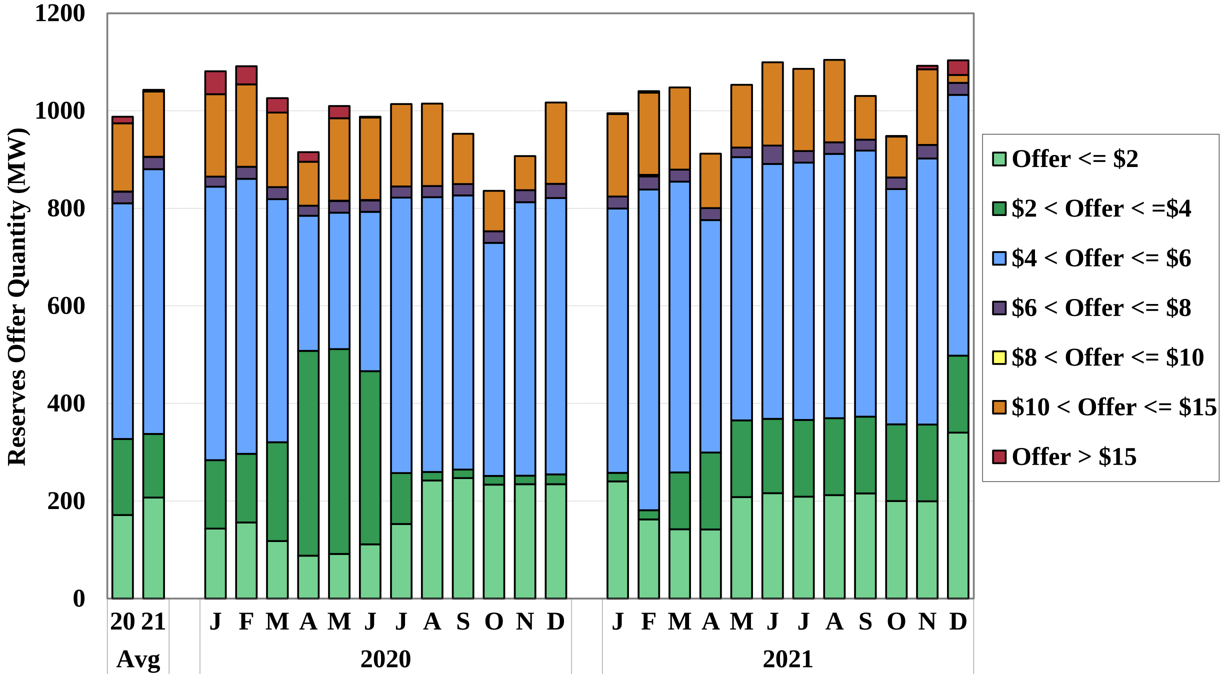
Figure A-37 to Figure A-41: Summary of Day-ahead Ancillary Services Offers

The following figures show ancillary services offers for generators in the day-ahead market for 2020 and 2021 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,[270]
- 30-minute operating reserves in NYCA,[271] and
- Regulation.[272]

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

Figure A-37: Summary of West 10-Minute Spinning Reserves Offers
Day-Ahead Market, 2020 – 2021



270 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.

271 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.

272 Regulation offers shown are a composite of the offered capacity and movement.

Figure A-38: Summary of East 10-Minute Spinning Reserves Offers
Day-Ahead Market, 2020 – 2021

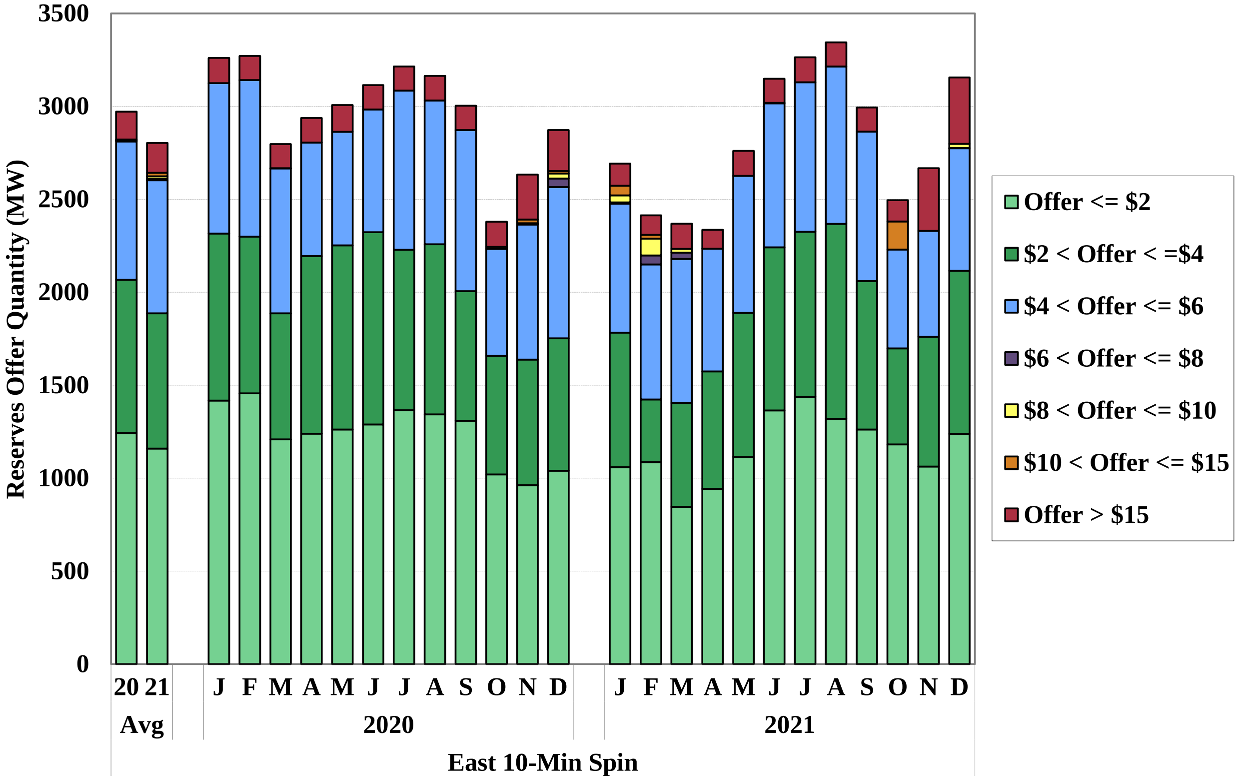


Figure A-39: Summary of East 10-Minute Non-Spin Reserves Offers
Day-Ahead Market, 2020 – 2021

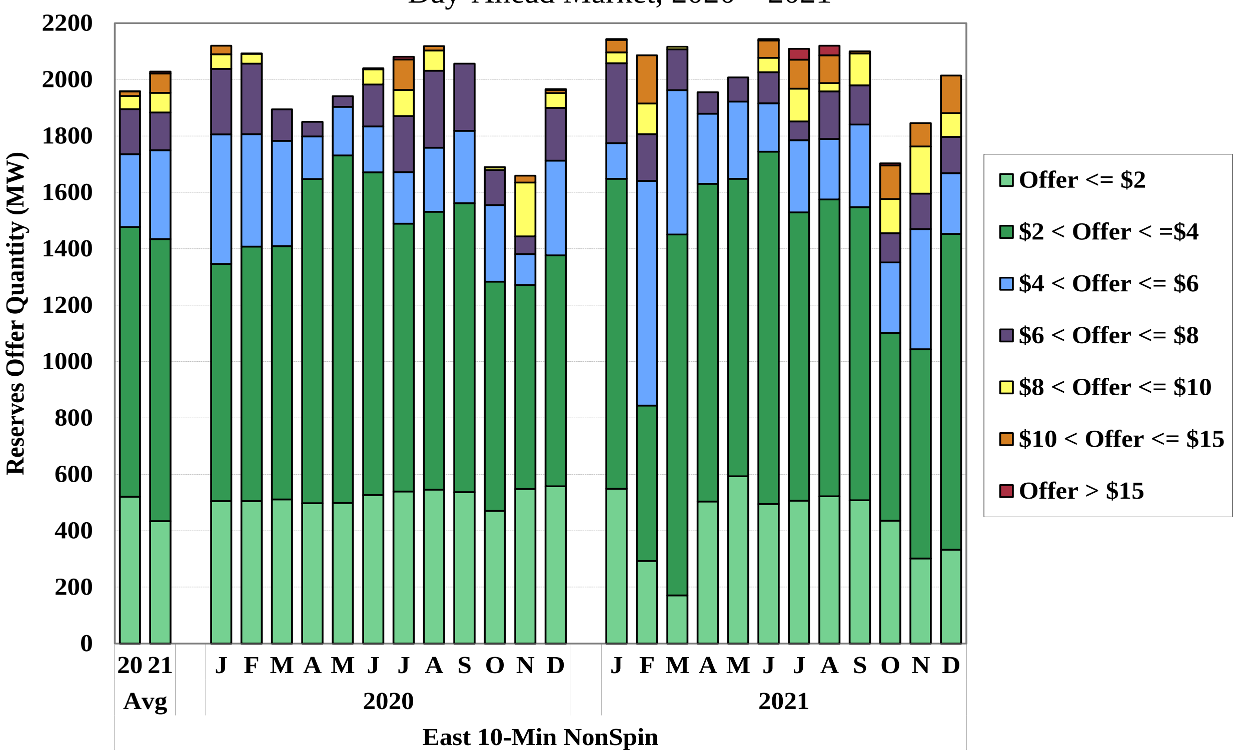


Figure A-40: Summary of NYCA 30-Minute Operating Reserves Offers
Excluding 10-minute, Day-Ahead Market, 2020 – 2021

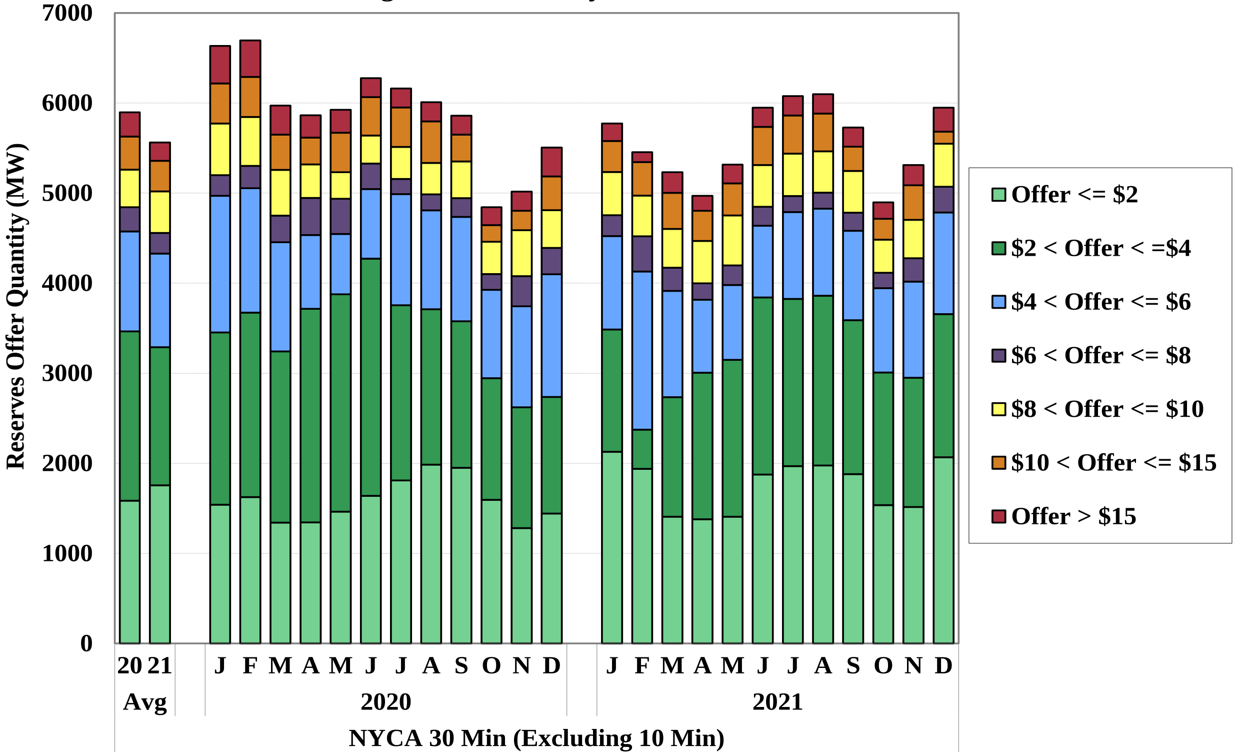


Figure A-41: Summary of Regulation Offers
Day-Ahead Market, 2020 – 2021

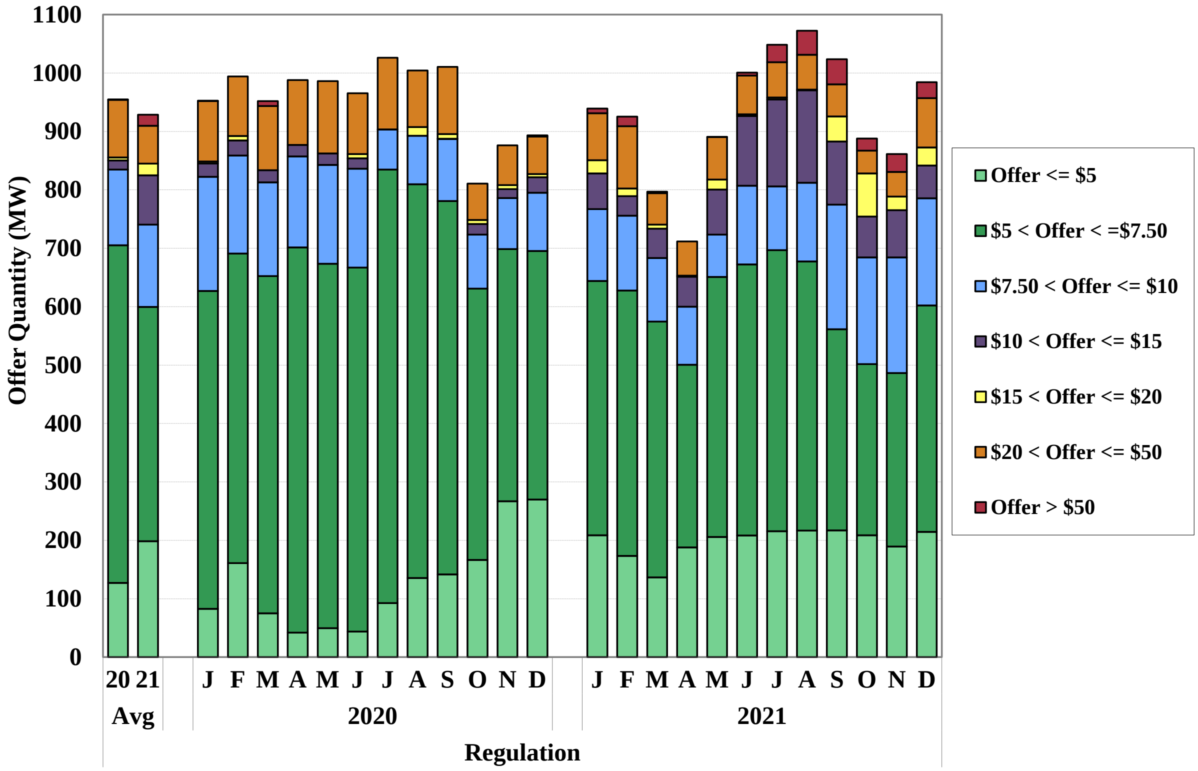


Figure A-42 to Figure A-43: Day-Ahead Reserve Offers That Satisfy NYCA 30-Minute Requirement and NYC Reserve Requirement

Figure A-42 summarizes reserve offers that can satisfy NYCA 30-minute operating reserve requirement in each quarter of 2019 to 2021 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-42 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-42: Day-Ahead Reserve Offers That Satisfy NYCA 30-Minute Requirement
Committed and Available Offline Quick-Start Resources, 2019 – 2021

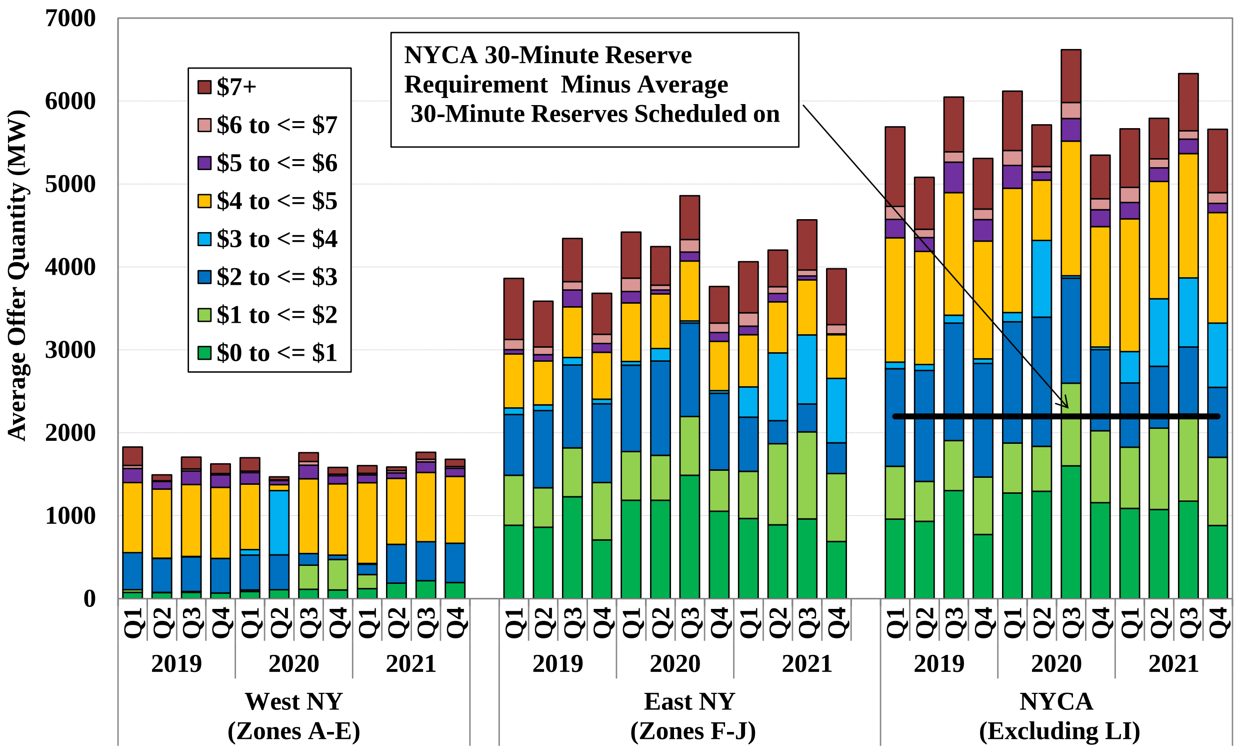


Figure A-43: Day-Ahead Reserve Offers that Satisfy NYC Reserve Requirement
Committed and Available Offline Quick-Start Resources, 2019 - 2021

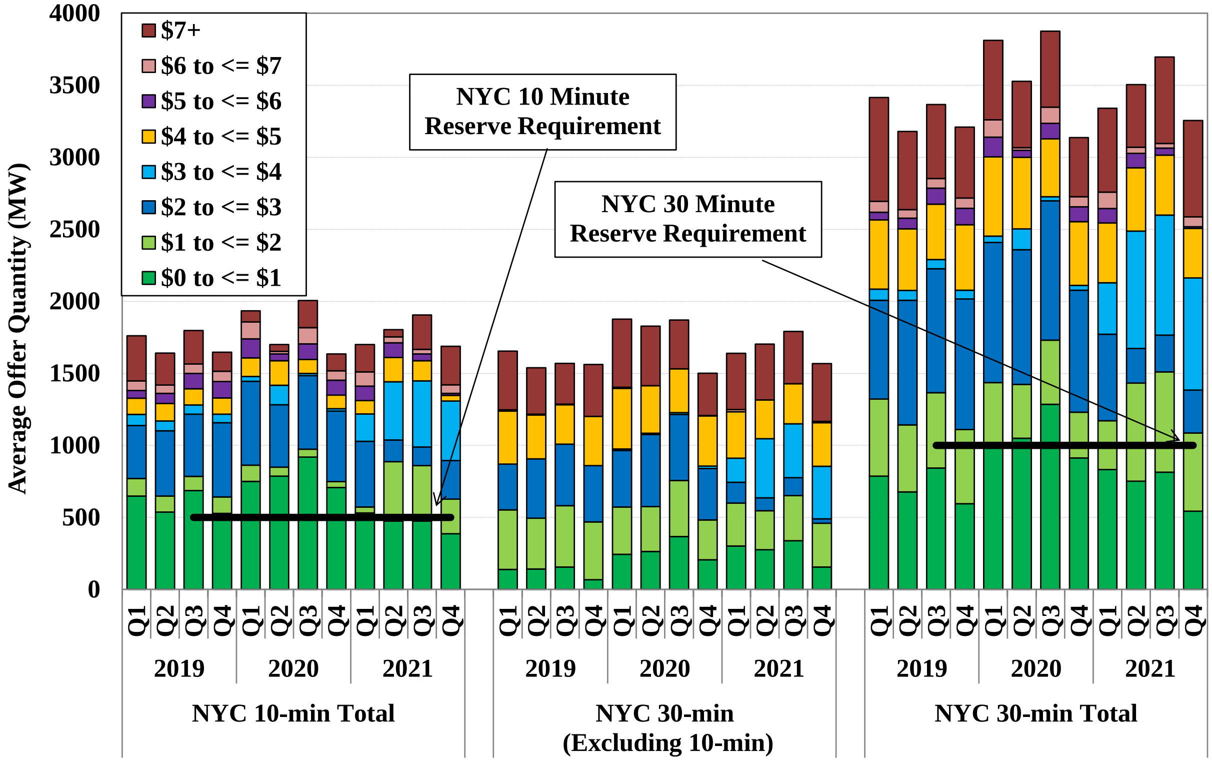


Figure A-43 summarizes offers that can satisfy the new NYC reserves requirement and shows NYC generator offers for 10- and 30-minute reserves from committed resources and available offline quick-start resources. The information is provided by quarter from 2019 and extending through 2021 for comparative 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-42, 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.

E. Analysis of Load Bidding and Virtual Trading

In addition to screening the conduct of suppliers for physical and economic withholding, it is important to evaluate how the behavior of buyers influences energy prices. Therefore, we evaluate whether load bidding is consistent with workable competition. Load can be scheduled in one of the following five ways:

- *Physical Bilateral Contracts* – These schedules allow participants to settle transmission charges (i.e., congestion and losses) with the NYISO between two points and to settle on the commodity sale privately with their counterparties. It does not represent all of the bilateral contracting in New York because participants have the option of entering into bilateral contracts that are settled privately (e.g., contracts for differences).

- *Day-Ahead Fixed Load* – This represents load scheduled in the day-ahead market for receipt at a specific bus regardless of the day-ahead price. It is the equivalent of a load bid with an infinite bid price.

- *Price-Capped Load Bids* – This is load bid into the day-ahead market with a bid price indicating the maximum amount the Load-Serving Entity ("LSE") is willing to pay.[273]

- *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-44 to Figure A-51: Day-Ahead Load Schedules versus Actual Load

Many generating units have long lead times and substantial commitment costs. Their owners must decide whether to commit them well in advance of real-time before they can be certain that the unit will be economic. The day-ahead market provides these suppliers with a means of being committed only when it is economic to do so. These suppliers are willing to sell into the day-ahead market if day-ahead prices are generally consistent with real-time prices. Thus, efficient unit commitment relies on consistency between the day-ahead and the real-time markets. The following figures help evaluate the consistency between day-ahead load scheduling patterns and actual load, providing an indication of the overall efficiency of the day-ahead market.

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

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

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

The following eight figures show day-ahead load schedules and bids as a percent of real-time load during daily peak load hours in 2020 and in 2021 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 2020 to 2021. Virtual imports and exports are shown for NYCA only and are not shown for any of the sub-areas in New York.

Figure A-44: Day-Ahead Load Schedules versus Actual Load in West Zone
Zone A, 2020 – 2021

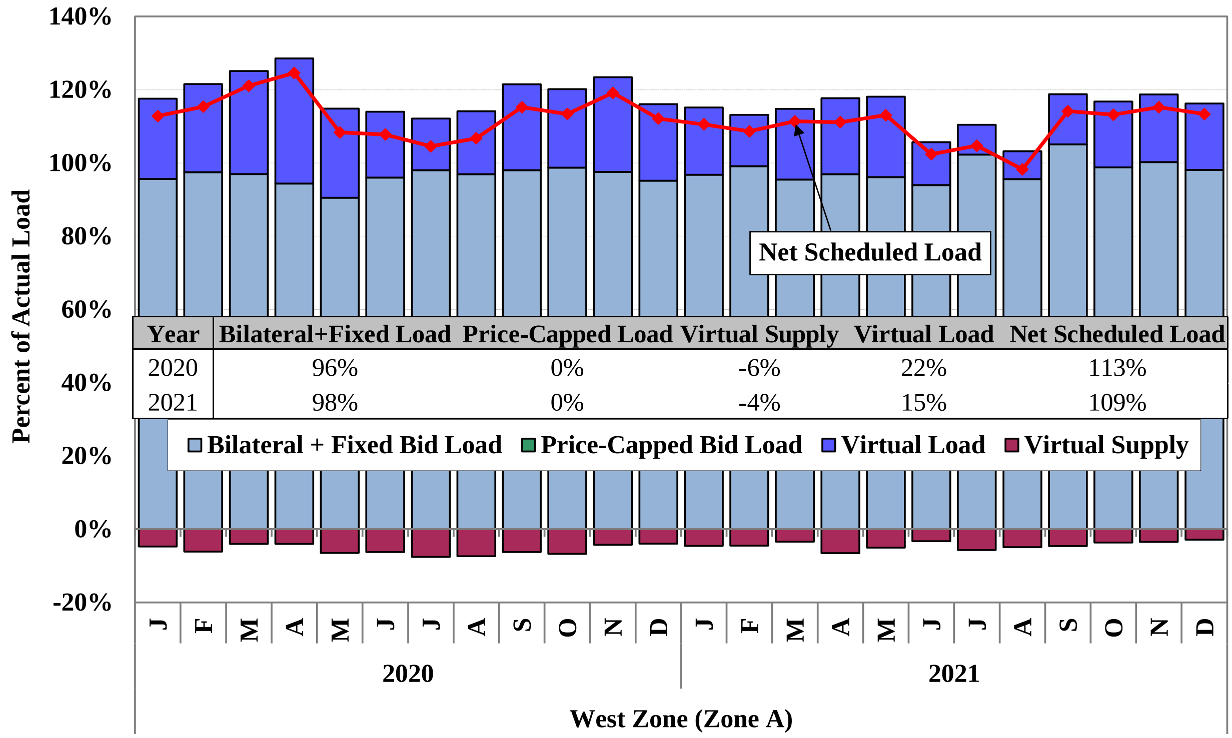
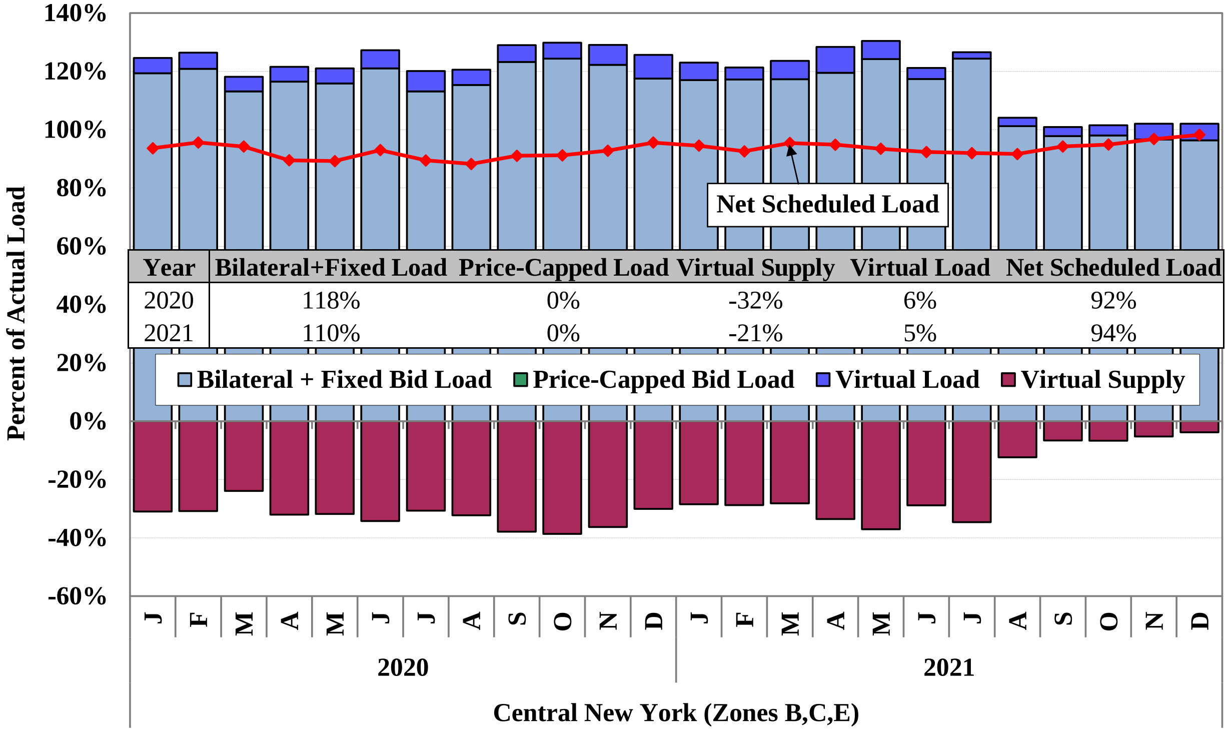


Figure A-45: Day-Ahead Load Schedules versus Actual Load in Central New York

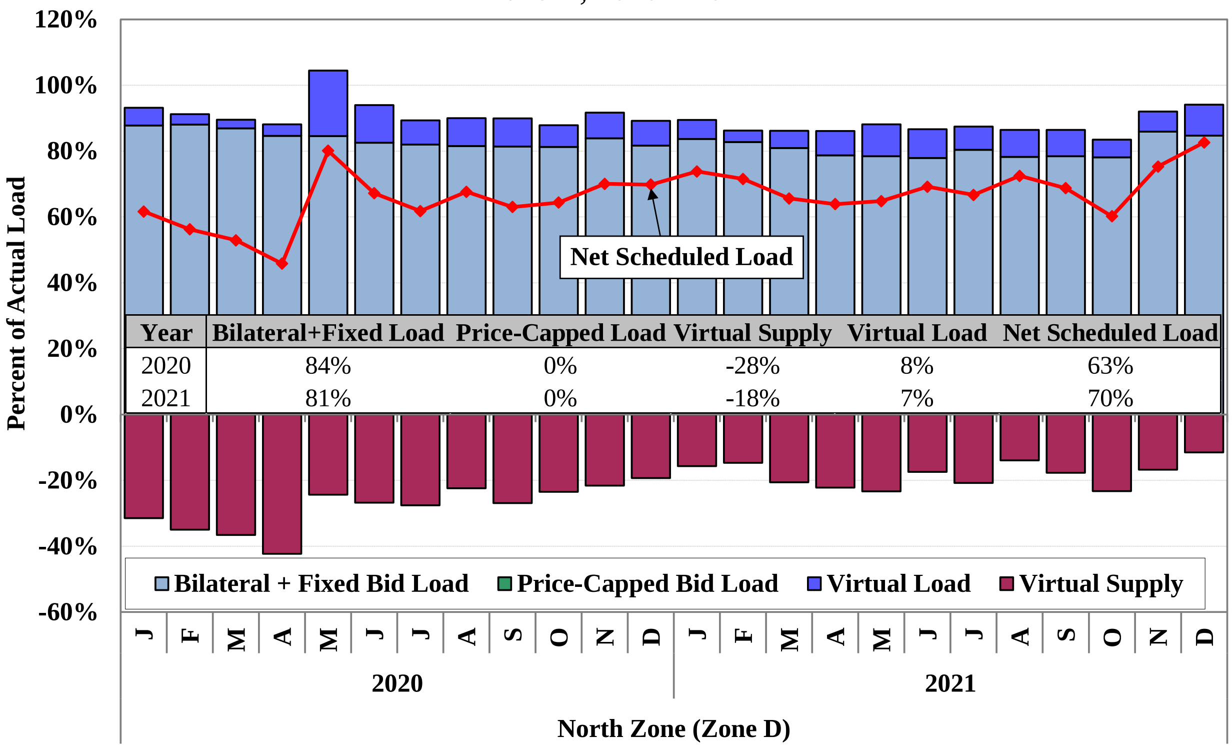
Zones B, C, & E, 2020 – 2021



Year	Bilateral+Fixed Load	Price-Capped Load	Virtual Supply	Virtual Load	Net Scheduled Load
2020	118%	0%	-32%	6%	92%
2021	110%	0%	-21%	5%	94%

Figure A-46: Day-Ahead Load Schedules versus Actual Load in North Zone

Zone D, 2020 – 2021



Year	Bilateral+Fixed Load	Price-Capped Load	Virtual Supply	Virtual Load	Net Scheduled Load
2020	84%	0%	-28%	8%	63%
2021	81%	0%	-18%	7%	70%

Figure A-47: Day-Ahead Load Schedules versus Actual Load in Capital Zone
Zone F, 2020 – 2021

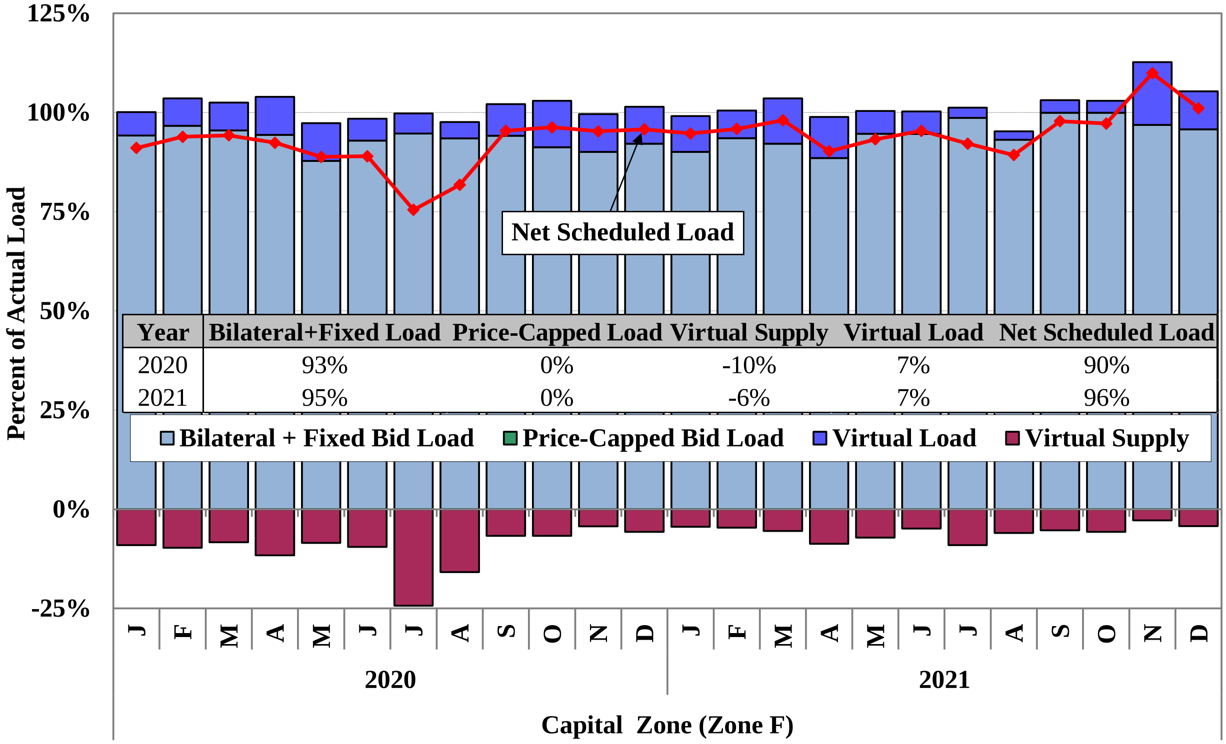


Figure A-48: Day-Ahead Load Schedules versus Actual Load in the Lower Hudson Valley
Zones G, H, & I, 2020 – 2021

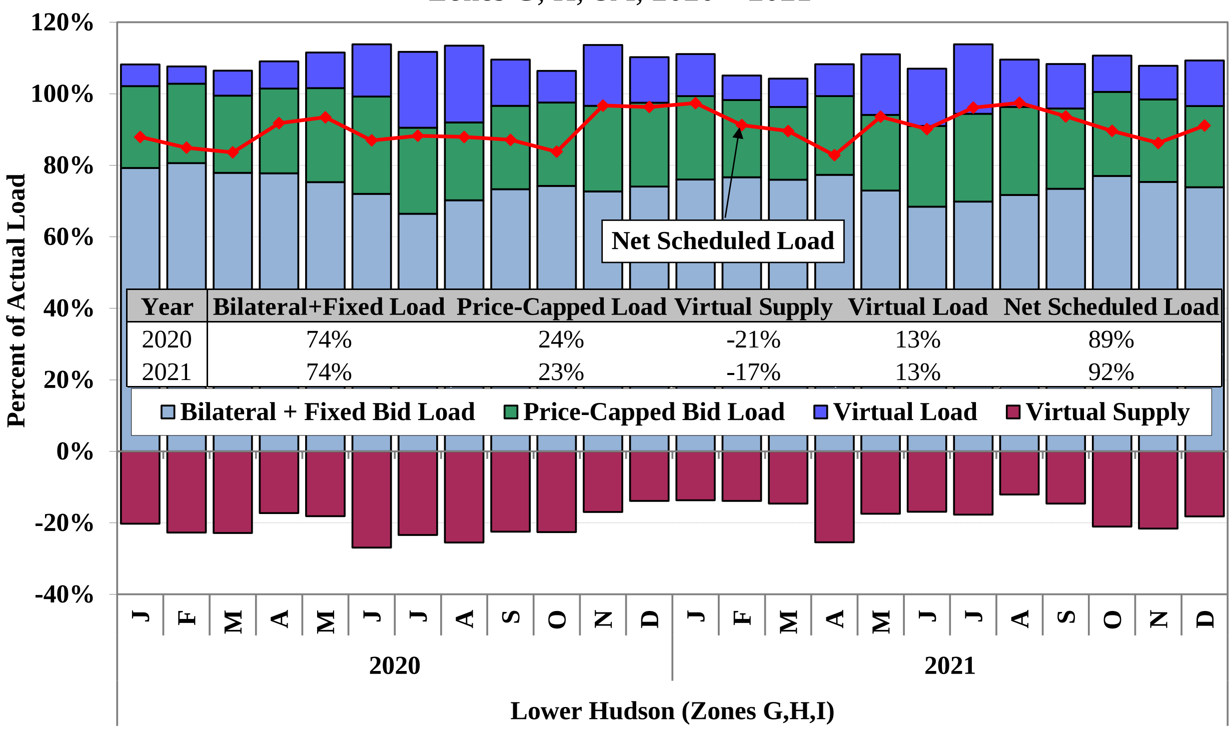


Figure A-49: Day-Ahead Load Schedules versus Actual Load in New York City

Zone J, 2020 – 2021

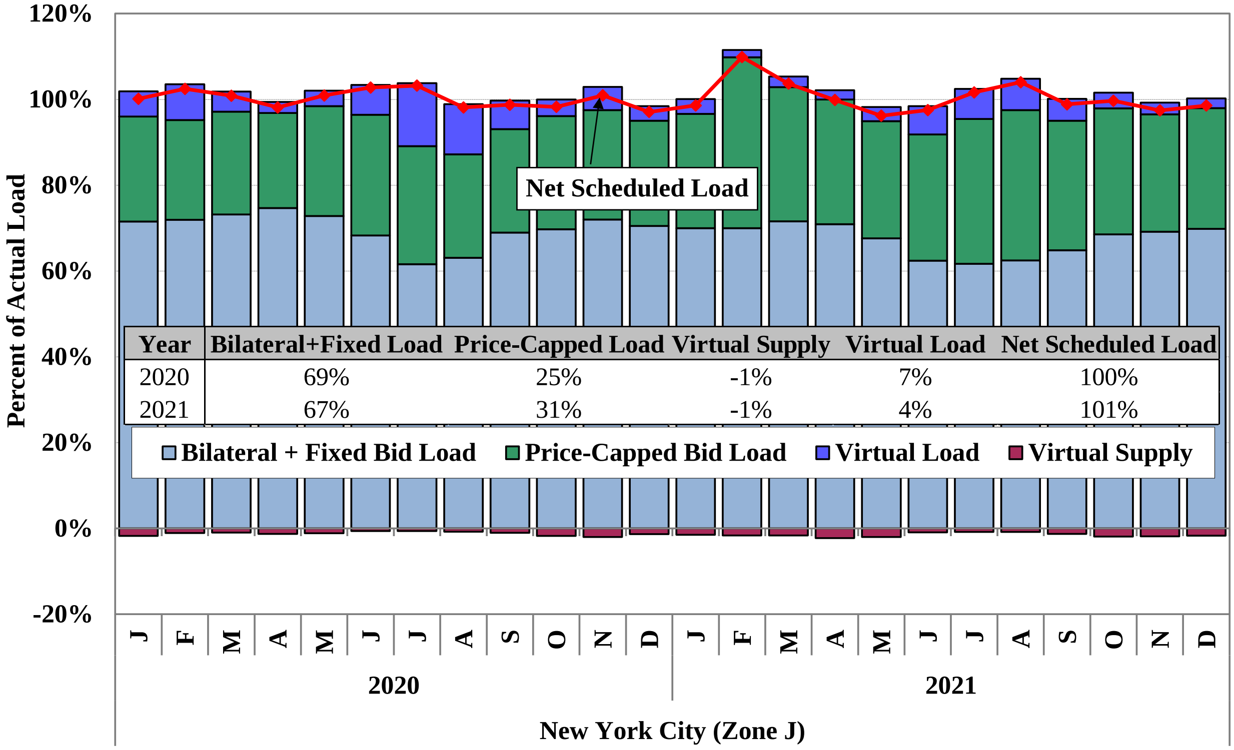


Figure A-50: Day-Ahead Load Schedules versus Actual Load in Long Island

Zone K, 2020 – 2021

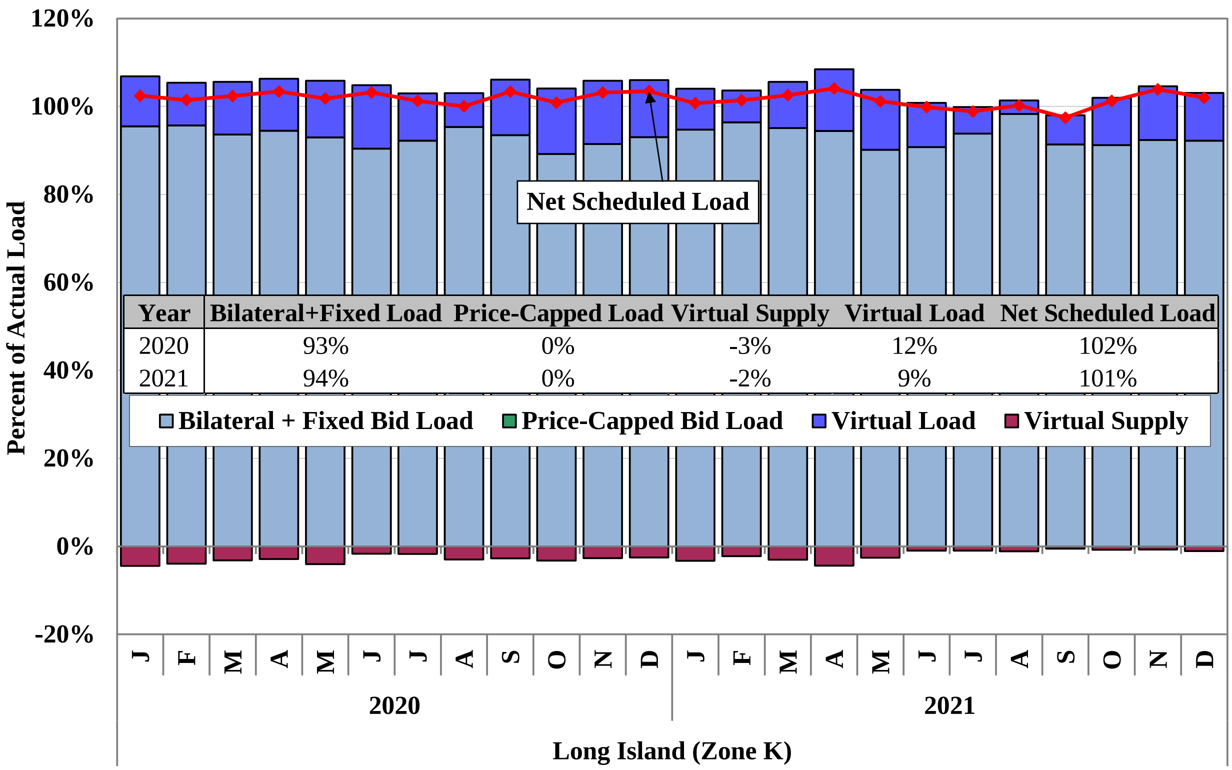
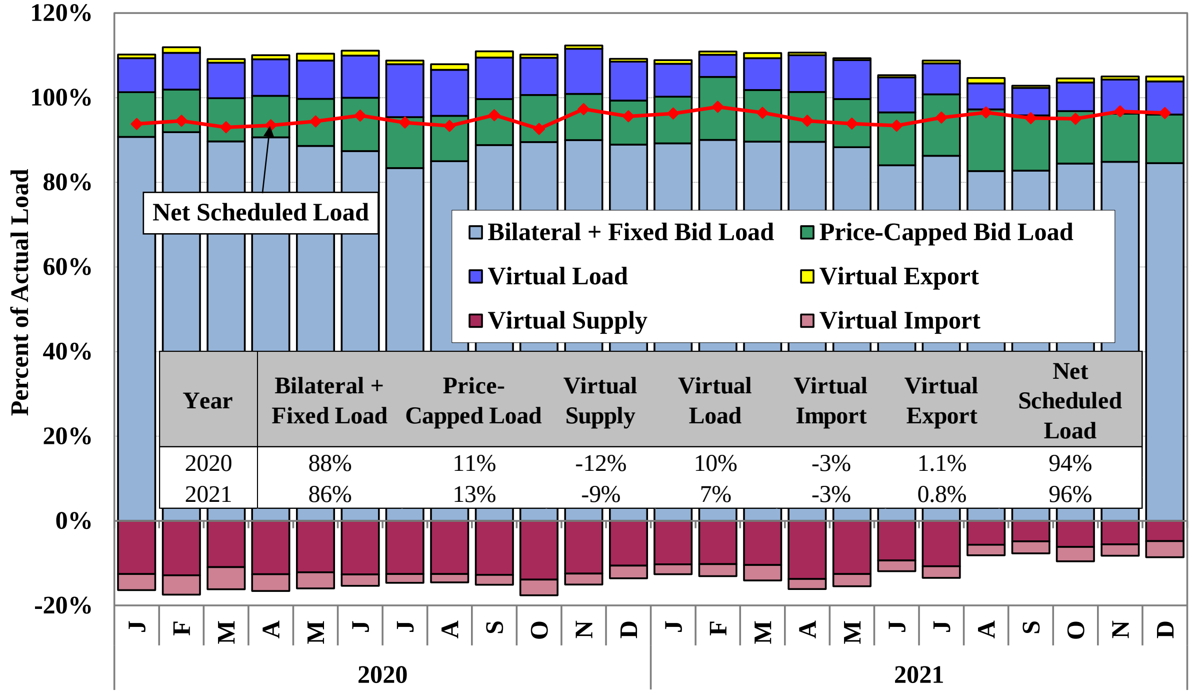


Figure A-51: Day-Ahead Load Schedules versus Actual Load in NYCA
2020 – 2021



Year	Bilateral + Fixed Load	Price-Capped Load	Virtual Supply	Virtual Load	Virtual Import	Virtual Export	Net Scheduled Load
2020	88%	11%	-12%	10%	-3%	1.1%	94%
2021	86%	13%	-9%	7%	-3%	0.8%	96%

F. Virtual Trading in New York

Virtual trading plays an important role in 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 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 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.

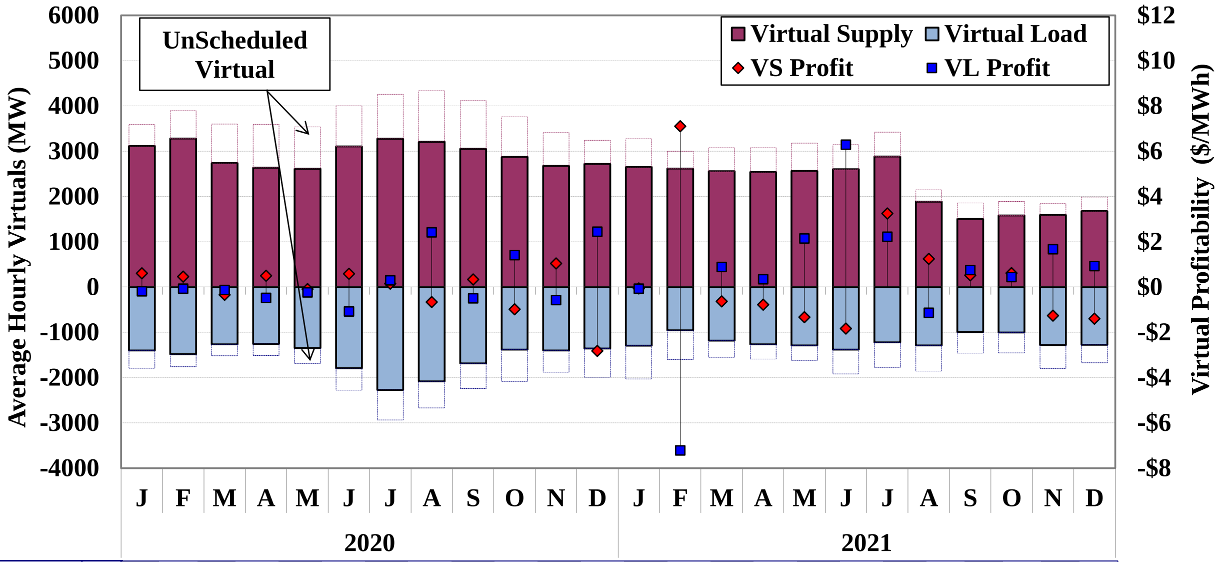
Figure A-52: Virtual Trading Volumes and Profitability

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 2020 and 2021. 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.[274,275]

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-52: Virtual Trading Volumes and Profitability

2020 – 2021



Profit > 50% of Avg. Zone Price	MW	421	322	232	370	388	464	416	377	196	235	619	375	320	658	514	549	378	325	413	158	158	96	182	195
	%	9%	7%	6%	10%	10%	9%	8%	7%	4%	6%	15%	9%	8%	18%	14%	14%	10%	8%	10%	5%	6%	4%	6%	7%
Loss > 50% of Avg. Zone Price	MW	338	253	321	298	404	460	377	304	198	312	528	440	283	388	491	688	498	271	234	174	140	88	197	215
	%	7%	5%	8%	8%	10%	9%	7%	6%	4%	7%	13%	11%	7%	11%	13%	18%	13%	7%	6%	5%	6%	3%	7%	7%

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

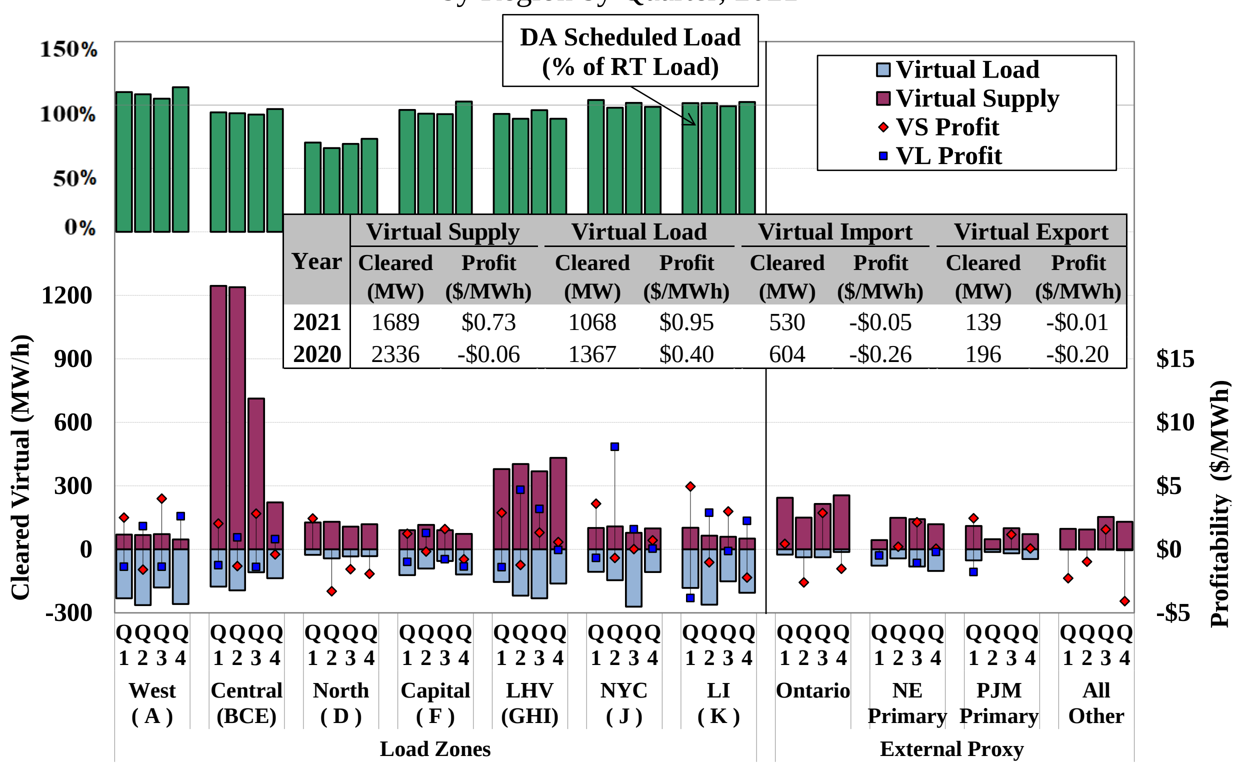
275 The calculation of the gross profitability for virtual imports and exports does not account for the profit (or loss) related to price differences between day-ahead and real-time in the neighboring markets.

Figure A-53: Virtual Trading Activity

Figure A-53 summarizes virtual trading by geographic region. The eleven zones in New York are broken into seven geographic regions based on typical congestion patterns. Zone A (the West Zone) is shown separately because of increased congestion in recent years. Zone D (the North Zone) is shown separately because generation in that zone exacerbates transmission congestion on several interfaces, particularly the Central-East interface. Zone F (the Capital Zone) is shown separately because it is constrained from Western New York by the Central-East Interface and from Southeast New York by constraints in the Hudson Valley. Zones J (New York City) and K (Long Island) are shown separately because congestion frequently leads to price separation between them and other areas. The figure also shows virtual imports and exports with neighboring control areas. The Ontario proxy bus, the primary PJM proxy bus (i.e., the Keystone proxy bus), and the primary New England proxy bus (i.e., the Sandy Pond proxy bus) are evaluated separately from all other proxy buses.

The lower portion of the figure shows average quantities of scheduled virtual supply and virtual load and their gross profitability for the seven regions and four groups of external proxy buses in each quarter of 2021. 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 2020 and 2021.

Figure A-53: Virtual Trading Activity [276]
by Region by Quarter, 2021



Year	Virtual Supply		Virtual Load		Virtual Import		Virtual Export	
	Cleared (MW)	Profit ($/MWh)	Cleared (MW)	Profit ($/MWh)	Cleared (MW)	Profit ($/MWh)	Cleared (MW)	Profit ($/MWh)
2021	1689	$0.73	1068	$0.95	530	-$0.05	139	-$0.01
2020	2336	-$0.06	1367	$0.40	604	-$0.26	196	-$0.20

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

III. TRANSMISSION CONGESTION

Congestion arises when the transmission network does not have sufficient capacity to dispatch the least expensive generators to satisfy the demands of the system. When congestion occurs, the market software establishes clearing prices that vary by location to reflect the cost of meeting load at each location. These Location-Based Marginal Prices ("LBMPs") reflect that higher-cost generation is required at locations where transmission constraints prevent the free flow of power from the lowest-cost resources.

The day-ahead market is a forward market that facilitates financial transactions among participants. The NYISO allows market participants to schedule transactions in the day-ahead market based on the predicted transmission capacity, resulting in congestion when some bids to purchase and offers to sell are not scheduled in order to reduce flows over constrained facilities. Congestion charges are applied to purchases and sales in the day-ahead and real-time markets based on the congestion component of the LBMP. Bilateral transactions scheduled through the ISO are charged the difference between the LBMPs of the two locations (i.e., the price at the sink minus the price at the source).

Market participants can hedge congestion charges in the day-ahead market by owning TCCs, which entitle the holder to payments corresponding to the congestion charges between two locations. A TCC consists of a source location, a sink location, and a quantity (MW). For example, if a participant holds 150 MW of TCC rights from zone A to zone B, this participant is entitled to 150 times the difference between the congestion prices at zone B and zone A. Excepting transmission losses, a participant can perfectly hedge a bilateral contract between two points if it owns a TCC between the points.

Incremental changes in generation and load from the day-ahead market to the real-time market are subject to congestion charges or payments in the real-time market. As in the day-ahead market, charges for bilateral transactions are based on the difference between the locational prices at the two locations of the bilateral contract. There are no TCCs for real-time congestion.

This section summarizes the following aspects of transmission congestion and locational pricing:

- Congestion Revenues and Patterns – Subsections A, 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 F and G analyze shortfalls in the day-ahead and real-time markets and identify major causes of shortfalls.

- Transmission Line Ratings – Subsection H analyzes the potential congestion benefit of using ambient-temperature adjusted line ratings in the market model.

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

- Transitioning Physical Contracts to Financial Rights – Subsection J 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.[277]

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.[278] 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.[279] 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

277 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).

278 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).

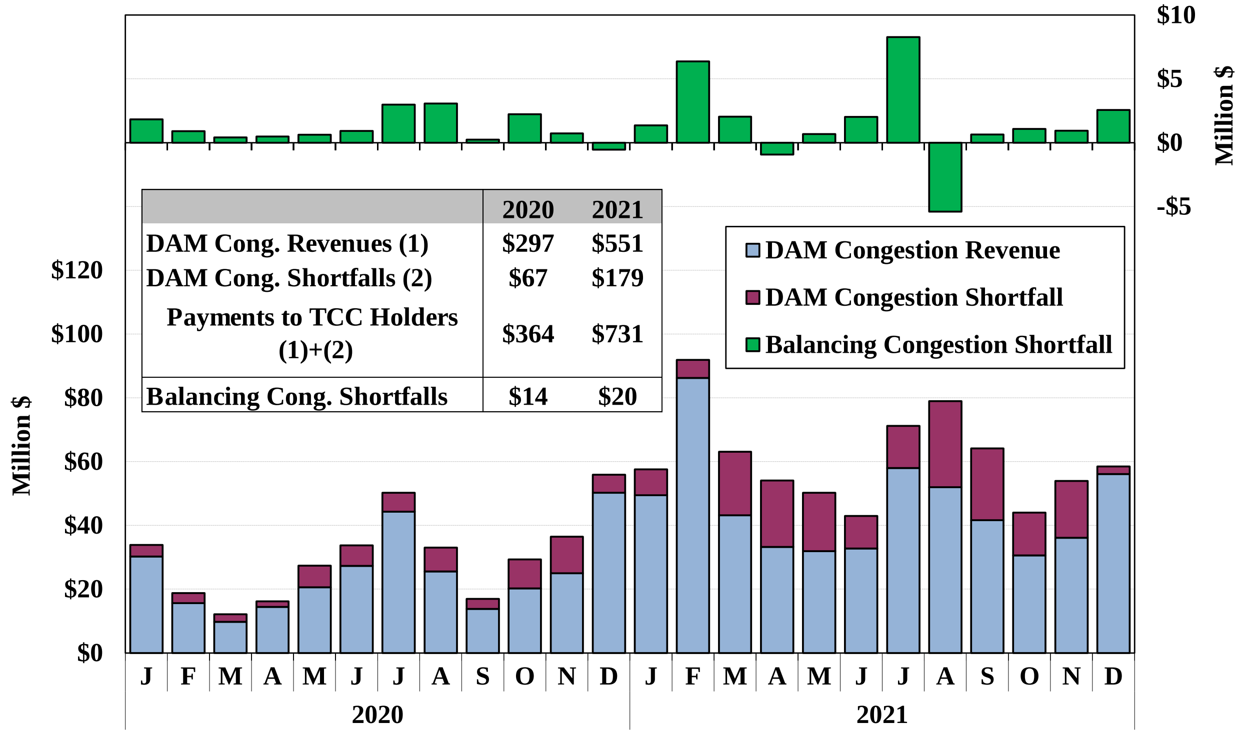
279 For example, suppose 100 MW is scheduled to flow across a particular line in the day-ahead market. If 90 MW flows across the line when it has a shadow price of $70/MWh in an hour in the real-time market, the NYISO will have a balancing congestion shortfall of $700 in that hour ((100 MW – 90 MW) * $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-54: Congestion Revenue Collections and Shortfalls

Figure A-54 shows day-ahead congestion revenue and the two classes of congestion shortfalls in each month of 2020 and 2021. 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-54: Congestion Revenue Collections and Shortfalls
2020 - 2021



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-55 to Figure A-57: Day-Ahead and Real-Time Congestion by Path

Figure A-55 to Figure A-57 show the value and frequency of congestion along major transmission lines in the day-ahead and real-time market. Figure A-55 compares these quantities in 2020 and 2021 on an annual basis, while Figure A-56 and Figure A-57 show the quantities separately for each quarter of 2021.

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.[280]

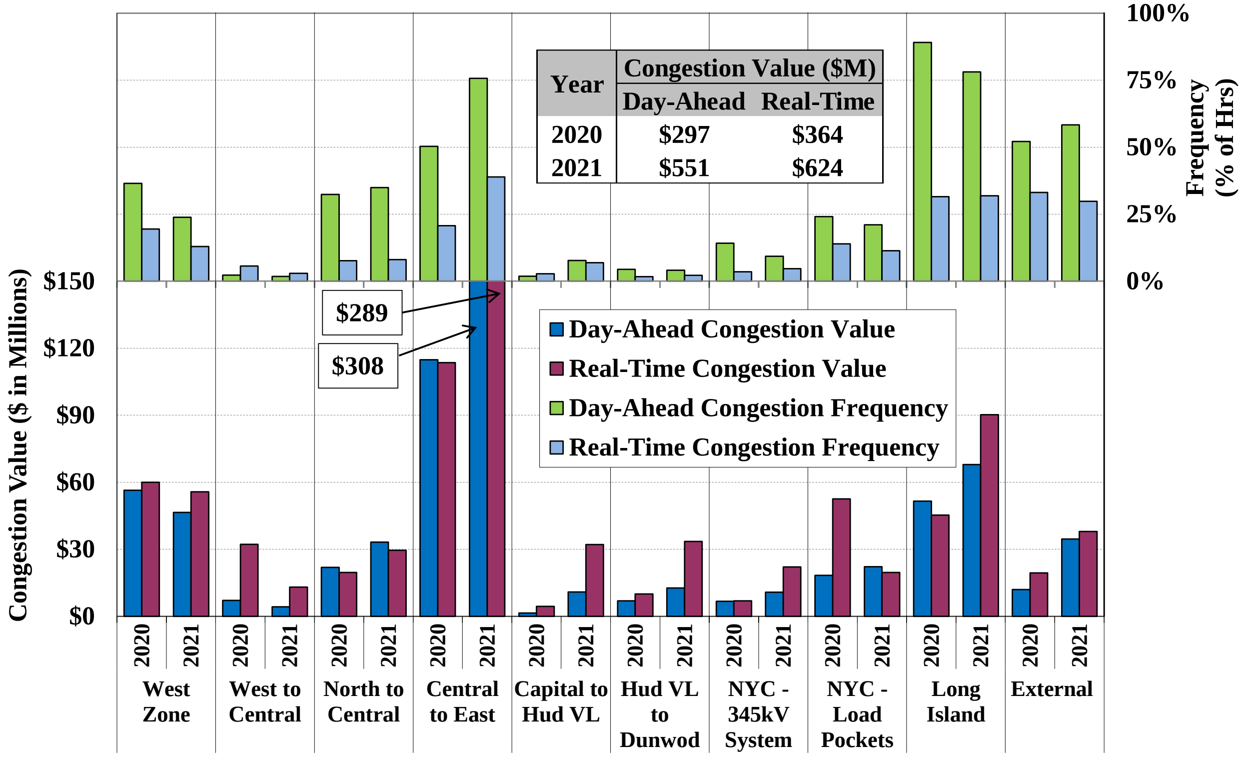
In the day-ahead market, the value of congestion equals the congestion revenue collected by the NYISO, which is the primary funding source for TCC payments. In the real-time market, the value of congestion does not equal the congestion revenue collected by the NYISO, since most real-time power flows 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).

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

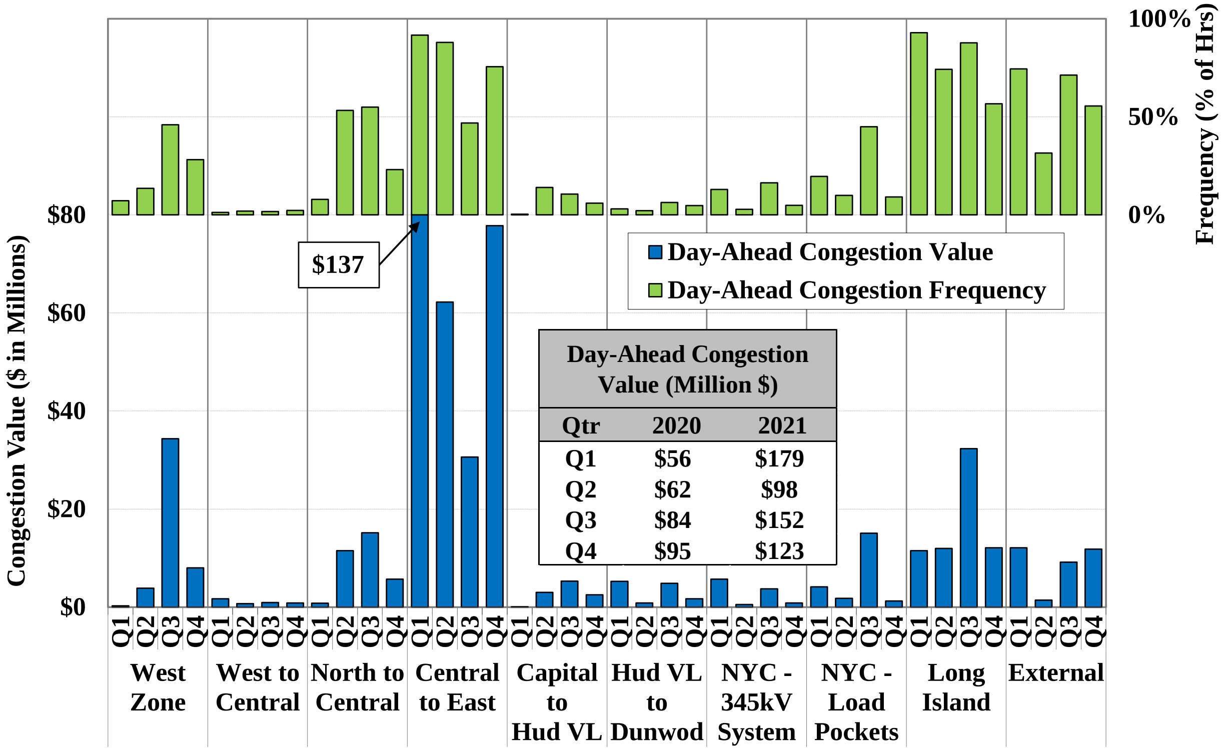
- Hudson Valley to Dunwoodie: Lines and interfaces leading into Dunwoodie from Hudson Valley.
- NYC Lines in 345 kV system: Lines leading into and within the New York City 345 kV system.
- NYC Lines in Load Pockets: Lines leading into and within New York City load pockets and groups of lines into load 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-55: Day-Ahead and Real-Time Congestion by Transmission Path
2020 – 2021



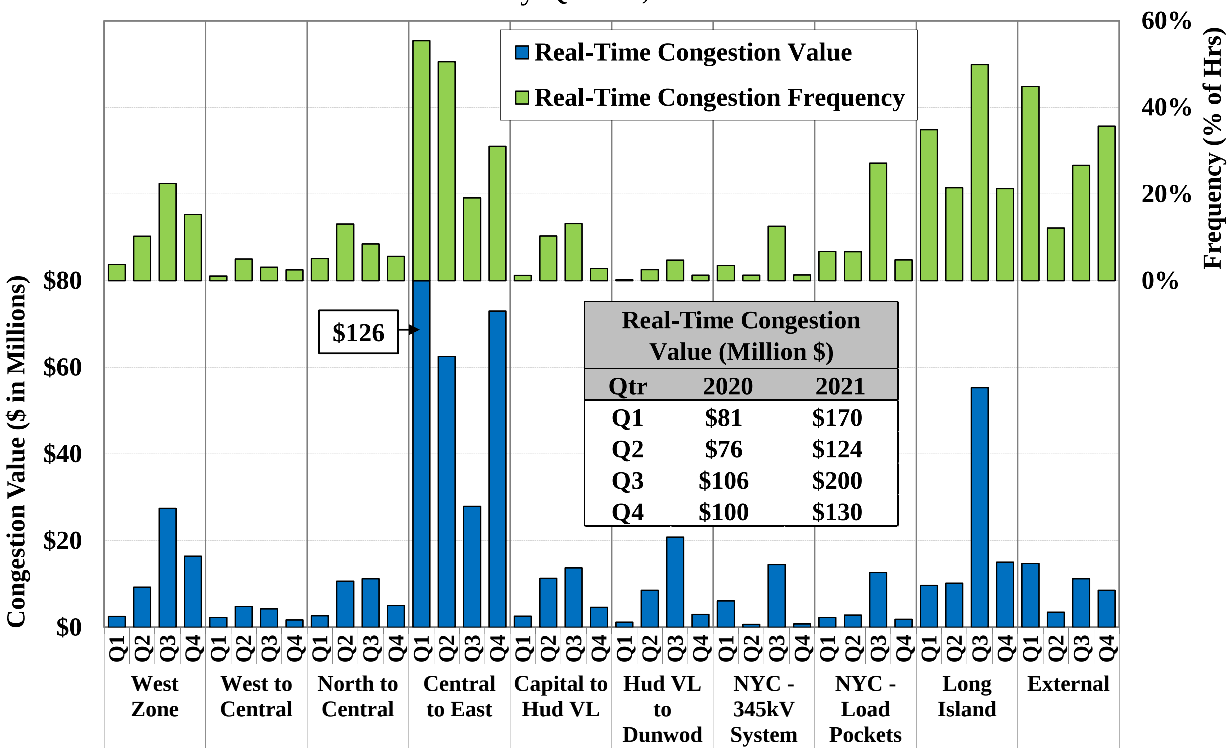
Year	Congestion Value ($M)	
	Day-Ahead	Real-Time
2020	$297	$364
2021	$551	$624

Figure A-56: Day-Ahead Congestion by Transmission Path
By Quarter, 2021



Day-Ahead Congestion Value (Million $)		
Qtr	2020	2021
Q1	$56	$179
Q2	$62	$98
Q3	$84	$152
Q4	$95	$123

Figure A-57: Real-Time Congestion by Transmission Path
By Quarter, 2021



Real-Time Congestion Value (Million $)		
Qtr	2020	2021
Q1	$81	$170
Q2	$76	$124
Q3	$106	$200
Q4	$100	$130

C. Real-Time Congestion Map by Generator Location

Figure A-58 to Figure A-59: 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-58 and Figure A-59 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 2021, 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 load-weighted using the New York systemwide load and presented as additional bubbles. These bubbles are not sized based on generation totals;[281] and
- Pertinent gas market information including regional gas prices in the systemwide map and key operational points of gas delivery in the NYC map.[282]

The generator nodes prices are displayed at bubbles that are sized based on annual average generation MWh. 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 average output all appear with the same size (i.e., the smallest sized bubble on the map), while generators with greater annual average outputs are shown with a size that increases with their annual average 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 average 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.

281 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.

282 Natural gas prices are based on the average index prices without additional adders sourced from Platts.

Figure A-58: NYCA Real-Time Load-Weighted Generator Congestion Map
2021

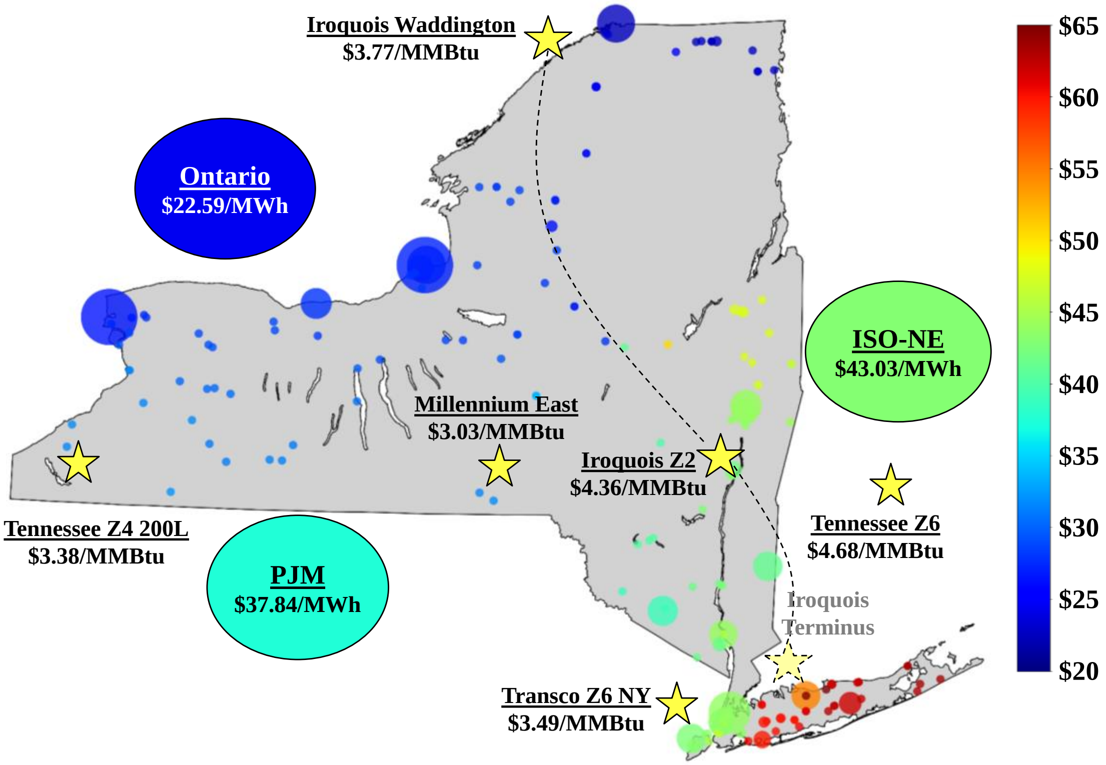
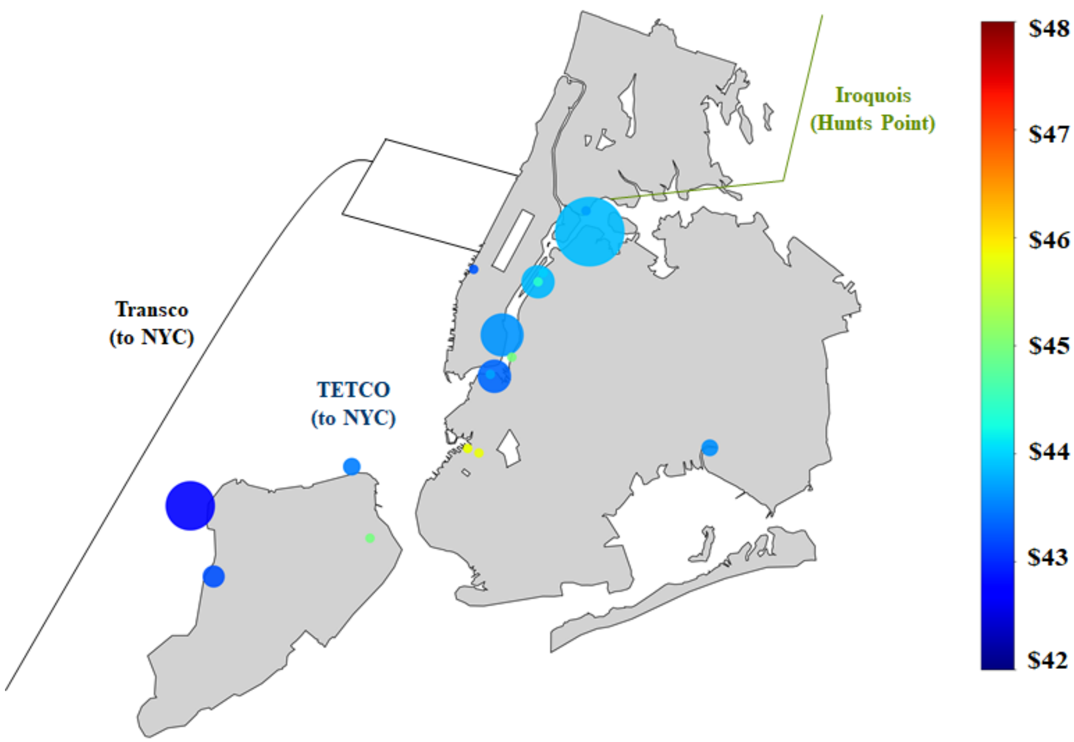


Figure A-59: NYC Real-Time Load-Weighted Generator Congestion Map
2021



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.[283] 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; and

- The potential pricing impact in several load pockets on Long Island.

Figure A-60 & Figure A-61: OOM-Managed Transmission Constraints on the Low Voltage Network

Figure A-60 shows the number of days in 2021 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.

Figure A-61 focuses on the area of Long Island, showing the number of hours and days in 2021 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;

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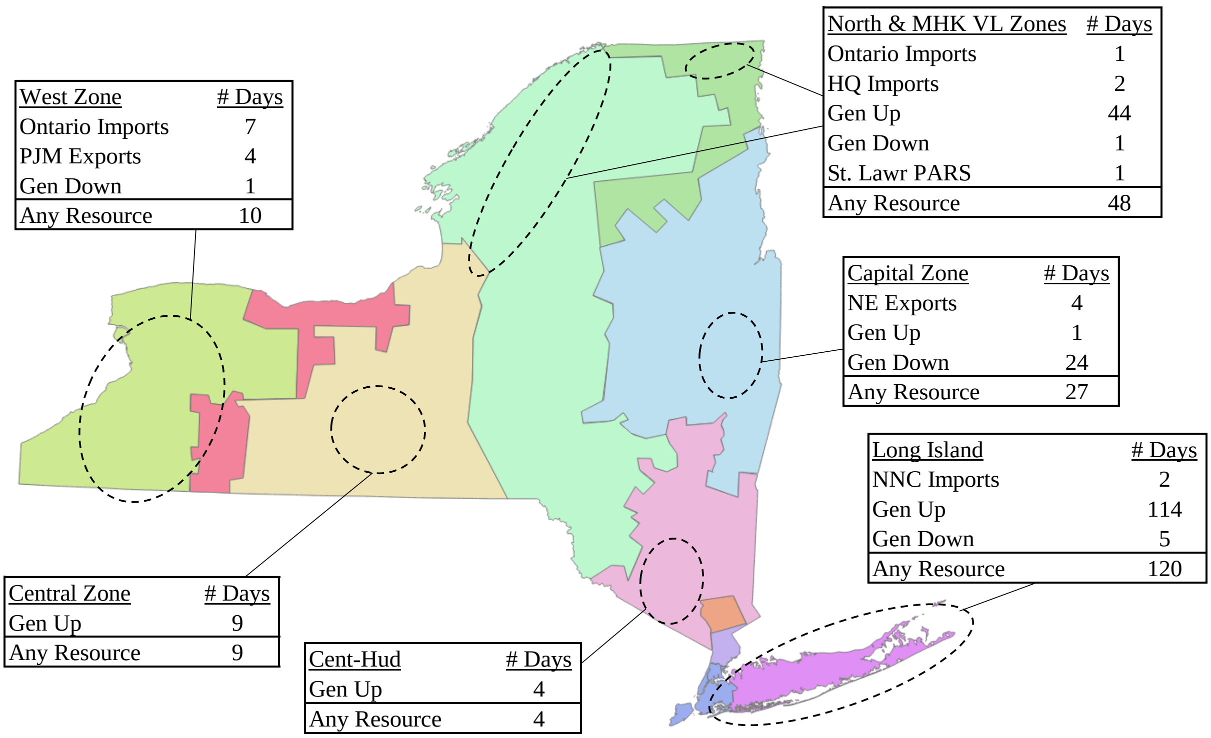
283 These constraints are sometimes managed with the use of line switching on the distribution system, but this is not included in our analysis here.

- East End: Mostly the constraints around the Riverhead bus and the TVR requirement.

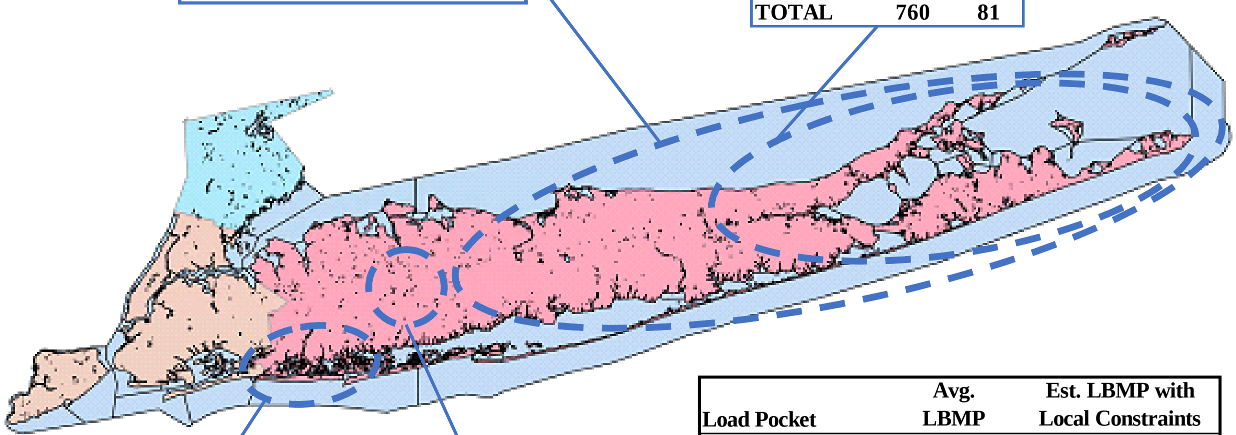
For a comparison, the tables also show the frequency of congestion management on the 138 kV constraint via the market model. Figure A-61 also shows our estimated price impacts in each Long Island load pocket that result from explicitly modeling these 69 kV and TVR constraints in the market software.[284]

Figure A-60: Constraints on the Low Voltage Network in New York
Summary of Resources Used to Manage Constraint, 2021



284 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-61: Constraints on the Low Voltage Network on Long Island
Frequency of Action Used to Manage Constraint, 2021



East of Northport	#Hours	#Days
69kV OOM	158	28
69kV	712	95
138kV	735	101
TOTAL	1144	138

East End	#Hours	#Days
69kV OOM	99	18
69kV	0	0
138kV	0	0
TVR OOM	669	65
TOTAL	760	81

Load Pocket	Avg. LBMP	Est. LBMP with Local Constraints
Brentwood	$55.45	$55.46
East End	$56.97	$69.12
East of Northport	$55.79	$57.43
Valley Stream	$53.78	$55.10

Brentwood	#Hours	#Days
69kV OOM	3	2
69kV	802	129
TOTAL	803	130

Valley Stream	#Hours	#Days
69kV OOM	535	70
138kV	1323	161
TOTAL	1808	207

E. Linear Constraints to Model Long Island East End TVR Requirements

Certain resources are required to be online to satisfy the Transient Voltage Recovery ("TVR") requirement on the East End of Long Island. [285] These required resources are expensive oil peakers, which are not often economically committed. Therefore, out-of-merit commitments are typically made by local TO based on operating guidelines. [286] These OOM commitments not only generate uplift but also depress real time prices on Long Island (see Figure A-61). It would be beneficial to model the requirements in the market software, which would lead to more efficient scheduling and pricing of resources on Long Island. This subsection describes an approach to model TVR requirements as linear constraints for the scheduling and pricing purpose.

There are three tables in the East End Operating Guideline that tabulate muliple operating options under different outage conditions and load levels. Table A-1 is one of the three tables in the Operating Guideline, which tabulates 10 resource commitment options when the Canal

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285 These resources include Global Greenport GT, East Hampton GT, South Hampton IC, East Hampton Diesel, and Southhold IC.

286 See *East End Operating Guideline*, available at: https://oasis.psegliny.com/c.cfm/Transmission_Owner_Information_Being_Released_to_Market.

DRSS is out of service and local load arises to different levels.[287] For example, 'Option 1' shows that, for the 'East Hampton Dynamic VAR Compensator In Service' scenario, Global Greenport GT should be first online to satisfy the TVR when local load arises to 115 MW, and then East Hampton GT should be brought online as load increases to 143 MW, and then East Hampton Diesel needs to be committed when load continues to rise to 160 MW, etc.

Table A-1: East End Operating Guideline

Canal DRSS Out of Service

SF Load (MW) E. HAMP D-VAR I/S	SF Load (MW) E. HAMP D-VAR O/S	Option 1	Option 2	Option 3	Option 4	Option 5	Option 6	Option 7	Option 8	Option 9	Option 10
115	104	GREENPORT GT						EHAMP GT		SHMP GT	
127	116									GRNPRT	EHMP GT
132	121							EHMP D	GRNPRT		
141	130							GRNPRT			
143	132	EHAMP GT		SHLD GT		EHAMP D					
144	133										EHMP D
152	141					EHAMP GT					
153	142										GRNPRT
155	144									EHMP D	
156	145			EHMP D	EHAMP GT						
160	149	EHMP D	SHMP GT						EHMP D		
164	153									EHMP GT	
165	154			EHAMP GT							
169	158	SHMP GT	EHMP D			SHLD GT	SHAMP GT				
173	162				EHMP D						
181	170	SHLD GT					SHLD GT				
182	171			SHAMP GT							
194	183	*Arm Under Voltage Load Shedding Scheme*									

Although the ten options in the table seemingly look unrelated, they do follow certain mathematical relationship between required resource capacity and local load levels. For illustration purpose, Table A-2 shows a numeric version of Table A-1 by replacing the five oil peakers with their 2021 Summer DMNC values (i.e, replacing Global Greenport GT with 52 MW, East Hampton GT with 18 MW, South Hampton IC with 8 MW, East Hampton Diesel with 6 MW, and Southhold IC with 10 MW)

287 This table is excerpted directly from the *East End Operating Guideline*.

Table A-2: East End TVR Commitment Options with Resource DMNC

Canal DRSS Out of Service

SF Load (MW) E. Hamp D-VAR I/S	SF Load (MW) E. Hamp D-VAR O/S	Option 1	Option 2	Option 3	Option 4	Option 5	Option 6	Option 7	Option 8	Option 9	Option 10
115	104	52	52	52	52	52	52	18	18	8	8
127	116									52	18
132	121							6	52		
141	130							52			
143	132	18	18	10	10	6	6				
144	133										6
152	141					18	18				
153	142										52
155	144									6	
156	145			6	18						
160	149	6	8						6		
164	153									18	
165	154			18							
169	158	8	6			10	8	8	8		
173	162				6						
181	170	10	10				10	10	10	10	10
182	171			8	8	8					
194	183	*ARM Under Voltage Load Shedding Scheme*									

The table shows the following two mathematic relationships:

- The load increments for the two transmission secnarios (i.e, East Hampton D-VAR I/S or O/S) are the same although their starting points are different. The load trigger starts at 115 MW when the D-VAR is in service but at 104 MW when it is out of service. The 11 MW of difference between the two transmission scenarios is persistent through all load levels. This is important for the derivation of the second mathematic relationship below.

- Each of the five resources satisfies the TVR for a constant range of load, which is in proportion to their DMNC values. For example, when Global Greenport GT is committed, it satisfies the TVR until the load increases by an additional 28 MW. In Option 1 to Option 6, Global Greenport GT is needed when load reaches 115 MW (use D-VAR I/S as an example), and another resource is needed when the load rises to 143 MW (143-125 = 28 MW). In Option 7, Global Greenport GT is needed when load is at 141 MW, and South Hampton IC is needed when load rises to 169 MW, again 169-141 = 28 MW. The same relationship holds for Option 8 (160-132=28MW), Option 9 (155-127=28MW), and Option 10 (181-153=28MW). The similar relationship can be derived for the other four resources as well, which are shown in Table A-3.

Table A-3: Relationship of Required TVR Commitments vs Load Levels

Canal DRSS Out of Service

SF Load (MW) E. Hamp D-VAR I/S	SF Load (MW) E. Hamp D-VAR O/S	Option 1	Option 2	Option 3	Option 4	Option 5	Option 6	Option 7	Option 8	Option 9	Option 10
115	104										
127	116									12	12
132	121							17	17		
141	130							9			
143	132	28	28	28	28	28	28				
144	133										17
152	141					9	9				
153	142										9
155	144									28	
156	145			13	13						
160	149	17	17						28		
164	153									9	
165	154			9							
169	158	9	9			17	17	28	9		
173	162				17						
181	170	12	12				12	12	12	17	28
182	171			17	9	13					
194	183	13	13	12	12	12	13	13	13	13	13

Table A-3 uses the same color scheme as in Table A-2. Each color-coded table entry indicates the 'covered range' of load MW for the represented resource, as explained above. The table shows that each color represents one constant load MW range. [288] We summarize these relationships in Table A-4 for each of five resources.

Table A-4: Summary of TVR Load Range vs Resource DMNC

	Resource Name	Generator	Summer DMNC MW	TVR Load Range MW	TVR Load Range/DMNC
	Greenport GT	G1	52	28	0.54
	E Hamp GT	G2	18	17	0.94
	S Hamp IC	G3	8	12	1.50
	E Hamp Diesel	G4	6	9	1.50
	Southhold IC	G5	10	13	1.30

Therefore, the following linear constraints could be developed in general for the TVR operating guideline in Table A-1:

- $0.54*G1 + 0.94*G2 + 1.5*G3 + 1.5*G4 + 1.3*G5 >= \text{Load} – (115-1)$ (for D-VAR I/S)

[288] The only exception is at the left bottom corner, where blue and yellow represent both 9 and 12.

- 0.54*G1 + 0.94*G2 + 1.5*G3 + 1.5*G4 + 1.3*G5 >= Load – (104-1) (for D-VAR O/S)

It is noted that the linear constraints should be written separately for commitment and pricing. Taken the 'D-VAR I/S' scenario as an example,

- For commitment, 0.54*C1 + 0.94*C2 + 1.5*C3 + 1.5*C4 + 1.3*C5 >= Load – 114, where C1-C5 are either 0 or individual UOL.

- For pricing, 0.54*G1 + 0.94*G2 + 1.5*G3 + 1.5*G4 + 1.3*G5 >= Load – 114, where G1-G5 are flexible from 0 to individual UOL.

These linear constraints could be developed similarly for all TVR requirements specified in the *East End Operating Guideline*, which provide a mechanism to efficiently schedule and price the TVR requirement through the market software rather than inefficient OOM actions and uplift payments.

F. Lake Erie Circulation and West Zone Congestion

The pattern of loop flows around Lake Erie has a significant effect on power flows in the surrounding control areas. Loop flows that move in a clockwise direction around Lake Erie generally exacerbate west-to-east transmission constraints in New York, leading to increased congestion costs in New York, while counter-clockwise loop flows alleviate west-to-east congestion in New York.

Phase angle regulators ("PARs") were installed at the interface between the MISO and IESO in April 2012 partly to control loop flows around Lake Erie. In general, these PARs are used to maintain loop flows at the MISO-IESO interface to less than 200 MW in either direction. Because of the configuration of surrounding systems, the volume and direction of loop flows at the MISO-IESO interface 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-62: Clockwise Loop Flows and West Zone Congestion

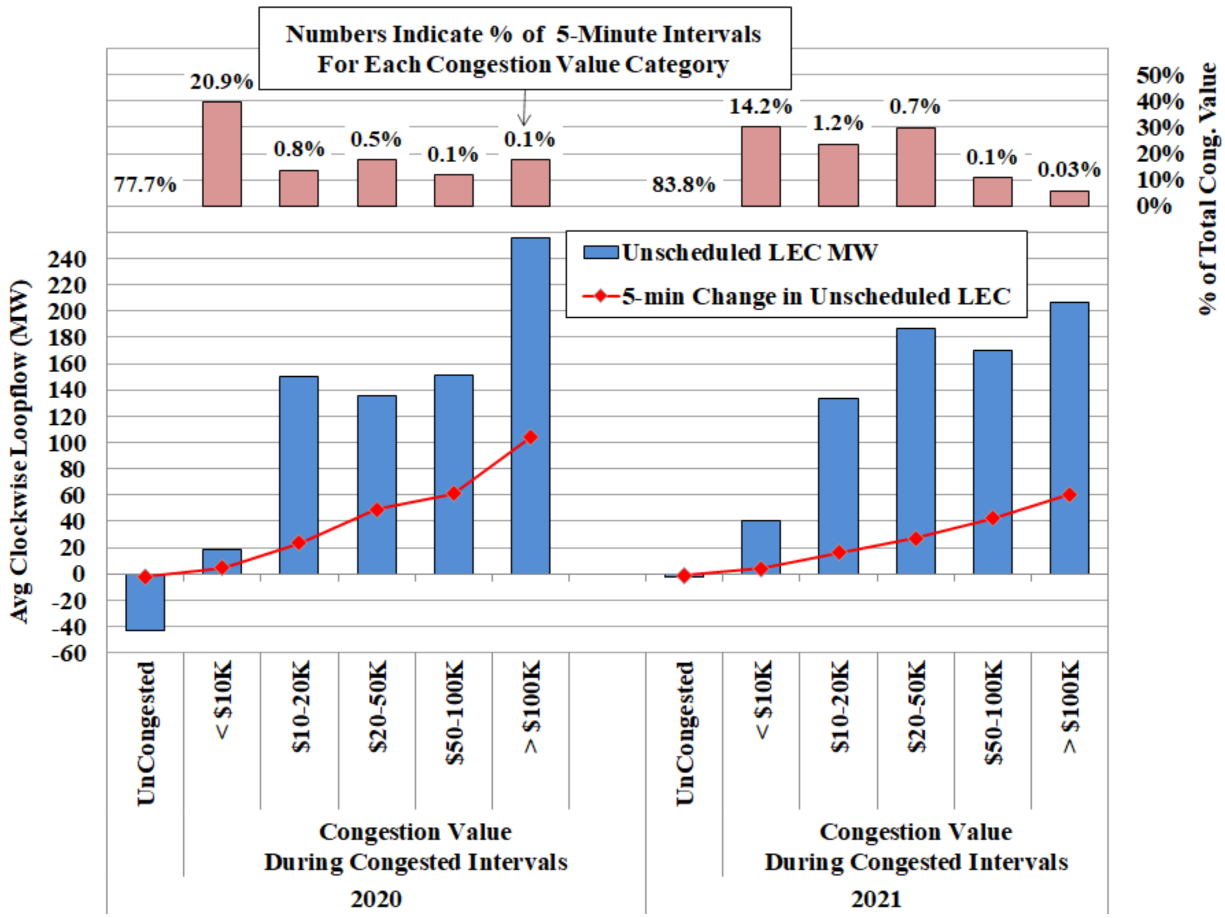
Unscheduled clockwise loop flows are primarily of concern in congested intervals, when they reduce the capacity available for scheduling internal generation to satisfy internal load and increase congestion on transmission paths in Western New York, particularly in the West Zone.

Figure A-62 illustrates how and to what extent unscheduled loop flows affected congestion on market-modeled West Zone constraints in 2020 and 2021. The bottom portion of the chart shows the average amount of: (a) unscheduled loop flows (blue bar); and (b) changes in unscheduled loop flows from the prior 5-minute interval (red line) during intervals when real-time congestion occurred on West Zone constraints. Congested intervals are grouped in the following ranges by congestion value: (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.[289] For comparison, these numbers are also shown for the intervals with no congestion.

In the top portion of the chart, the bars show the percent of total congestion values that each congestion value group accounted for in 2020 and in 2021, 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.

Figure A-62: Clockwise Lake Erie Circulation and West Zone Congestion
2020 – 2021



G. 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

289 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.

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-63: 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-63 shows day-ahead congestion shortfalls by transmission path or facility in each month of 2020 and 2021. Positive values indicate shortfalls, while negative values indicate surpluses. The shortfalls are shown for the following paths:

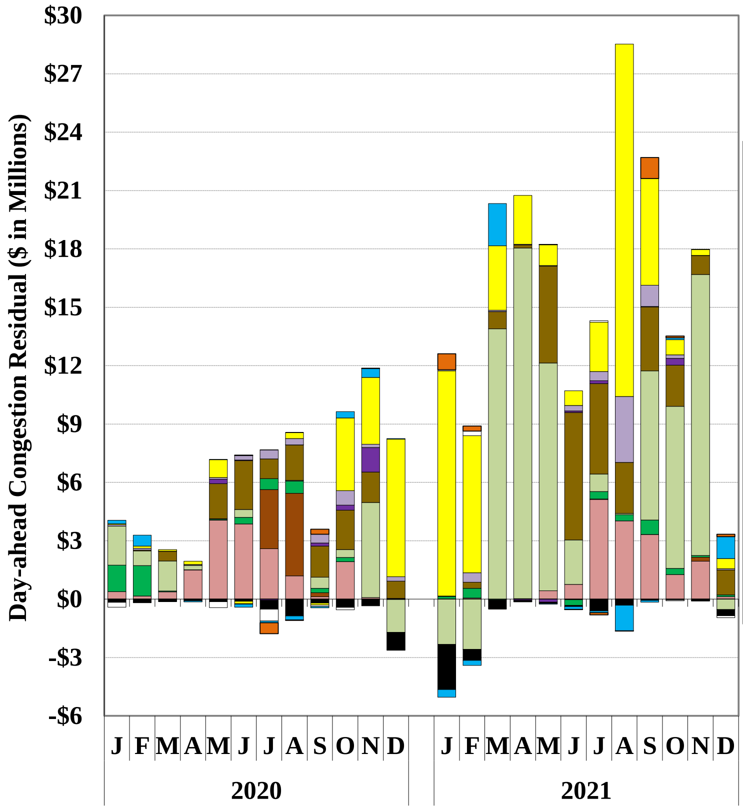
- West Zone Lines: Transmission lines in the West Zone.
- North to Central: Transmission lines in the North Zone, the Moses-South Interface, EDIC-Marcy 345 line, and Marcy 765-Marcy 345 line.
- Central to East: Primarily the Central-East interface.
- Capital to Hudson Valley: Transmission lines into Hudson Valley, primarily lines connecting Leeds, Pleasant Valley, and New Scotland stations.
- Hudson Valley to Dunwoodie: Primarily transmission lines at and around Buchanan that help flow power towards New York City and Long Island.
- 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 Long Island lines, the figure shows separately the shortfalls resulted from:
  - Differences in assumed schedules across the Pilgrim PAR controlled line between the TCC auction and the day-ahead market;
  - 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-63: Day-Ahead Congestion Shortfalls
2020 – 2021



	Category	Annual Shortfall ($M) 2020	2021
	Long Island Lines		
	Pilgrim PAR	$7.5	$0.2
	901/903 PARs	-$4.0	-$4.9
	Excess GFTCC Allocations	$2.9	$6.1
	Other Factors	$15.7	$54.0
	West Zone Lines	$16.3	$17.0
	North to Central	$13.8	$27.8
	Central to East	$9.2	$71.9
	New York City	$4.9	$2.3
	Capital to Hud VL	$1.9	$0.4
	Hud VL to Dunwod	-$0.3	$2.2
	External	$1.0	$1.1
	All Other Facilities	-$1.4	$0.2

Figure A-64: 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.

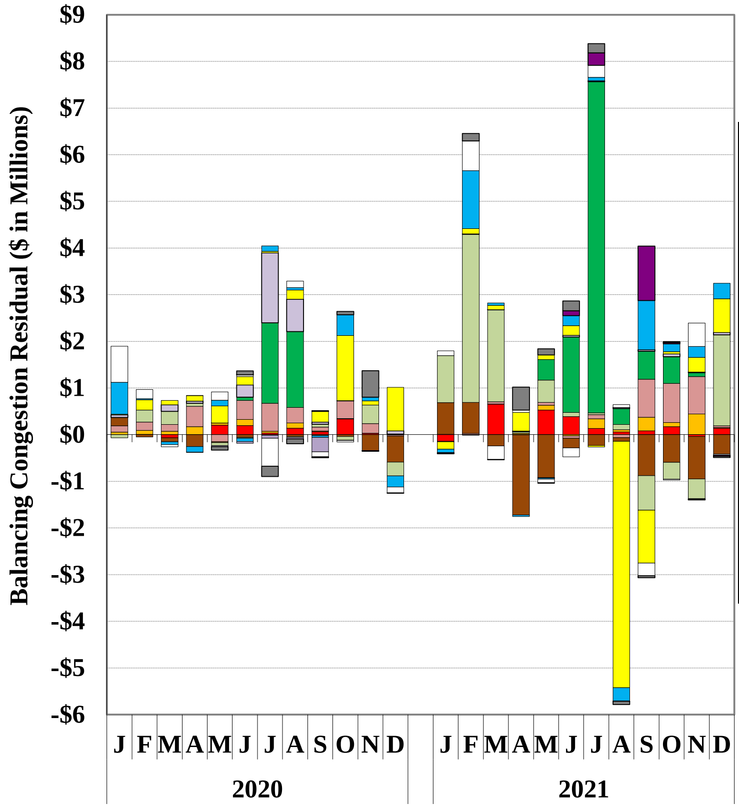
- PAR Controlled Line Flows – The flows across PAR-controlled lines are adjusted in real-time operations, which can result in flows that are very different from the day-ahead assumptions. These differences can affect the flows across multiple interfaces. This includes flow adjustments on PAR-controlled 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-63, Figure A-64 shows balancing congestion shortfalls by transmission path or facility in each month of 2020 and 2021. 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-64: Balancing Congestion Shortfalls[290]
2020 – 2021



Category	Annual Shortfall ($M) 2020	2021
West Zone Lines		
Ramapo, A & JK PARs	$0.7	$1.2
Other Factors	$2.7	$2.6
North to Central	$0.9	$2.0
Central to East		
Ramapo, A & JK PARs	-$1.3	-$4.8
Other Factors	$0.5	$7.8
TSA Constraints	$3.4	$10.8
Long Island Lines		
Pilgrim PAR	$2.8	$0.3
Other Factors	$3.9	-$4.6
Capital to Hud VL	$0.3	$1.0
Hud VL to Dunwoodie	$0.0	$1.5
External	$1.0	$2.9
All Other Facilities	$0.4	$0.7

H. 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.

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

The 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. 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-65: Potential Congestion Benefit of Using Ambient-Temperature Adjusted Ratings

Figure A-65 shows our estimate of potential congestion benefit from using ambient-temperature adjusted line ratings for 2019 to 2021.

We estimate ambient-adjusted ratings based on the following assumptions: [291]

- 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.[292] 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.[293] 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

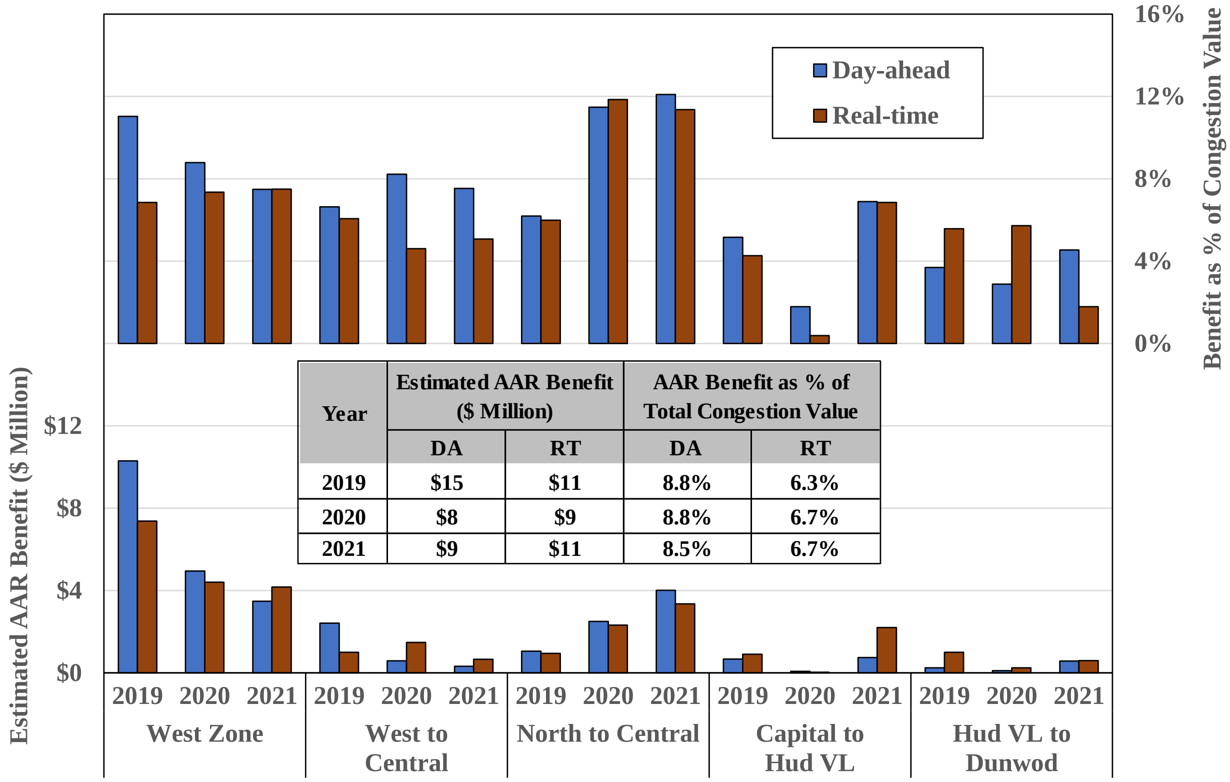
291 See "Tie-Line Ratings Task Force Final Report on Tie-Line Ratings" by New York Power Pool, 1995.

292 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.

293 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.

underground cables, whose ratings are not as sensitive to ambient air temperature as overhead lines.

Figure A-65: Potential Congestion Benefit of Using AAR Line Ratings
2019-2021



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%
2021	$9	$11	8.5%	6.7%

I. 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* [294] – 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-66: TCC Cost and Profit by Auction Round and Path Type

Figure A-66 summarizes TCC cost and profit for the Winter 2020/21 and Summer 2021 Capability Periods (i.e., the 12-month period from November 2020 through October 2021). The *TCC Cost* measures what market participants paid to obtain TCC rights from the TCC auctions. For a particular path, the *TCC Cost* is equal to the purchased TCC MW multiplied by the TCC price for that path. The *TCC Profit* measures the difference between the *TCC Payment*, which is equal to the TCC MW between two points multiplied by the congestion cost difference in the day-ahead market between the two points, and the *TCC Cost*.

The figure shows the TCC costs and profits for each round of auction in the 12-month period, which includes: (a) three rounds of one-year auctions for the exact same 12-month Capability Period; (b) four rounds of six-month auctions for the Winter 2020/21 Capability Period; (c) four rounds of six-month auctions for the Summer 2021 Capability Period; and (d) twelve Balance-of-Period auctions for each month of the 12-month Capability Period.[295] 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.[296]

294 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.

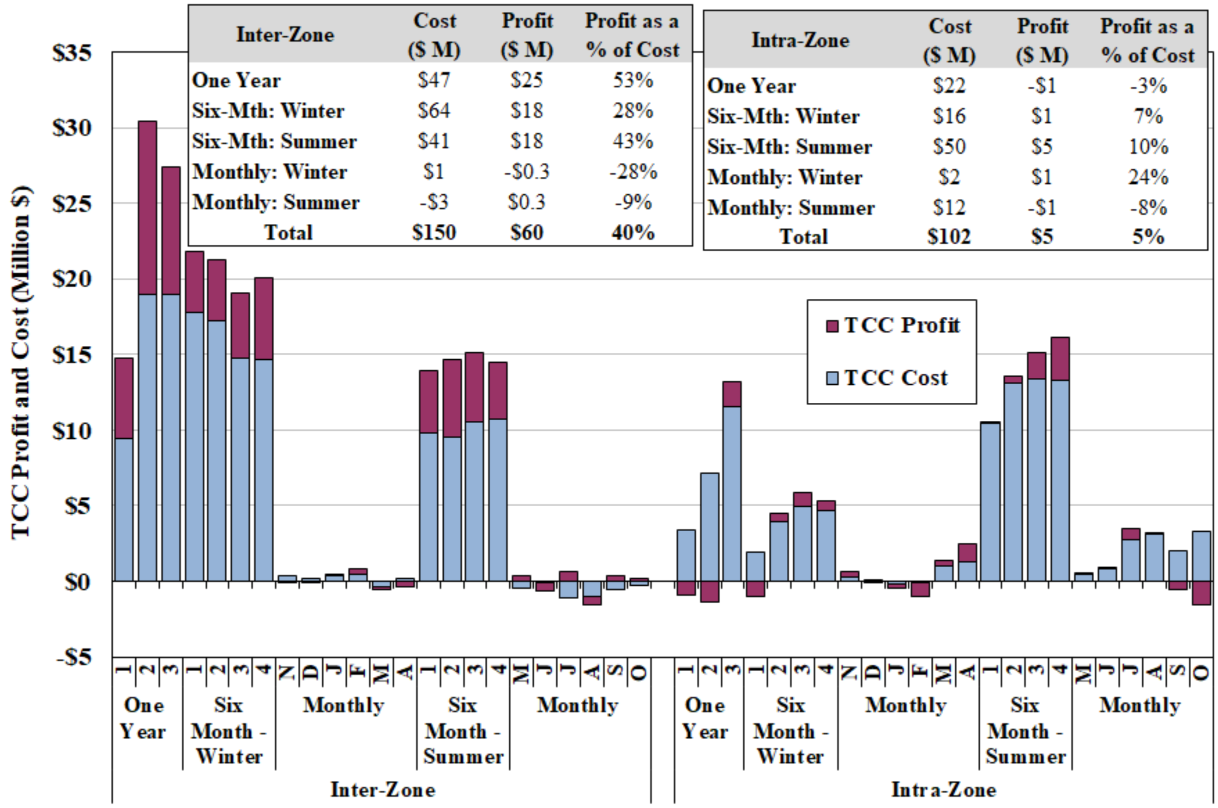
295 In the figure, the bars in the 'Monthly' category represent aggregated values for the same month from all applicable BOP auctions.

296 For example, a 100 MW TCC from Indian Point 2 to Arthur Kill 2 is unbundled to three components: (a) A 100 MW TCC from Indian Point 2 to Millwood Zone; (b) A 100 MW TCC from Millwood Zone to New York City Zone; and (c) A 100 MW TCC from New York City Zone to Arthur Kill 2. Components (a) and (c) belong to the intra-zone category and Component (b) belongs to inter-zone category.

The figure shows the costs and profits separately for the intra-zone and inter-zone components of TCCs. The table in the figure summarizes the TCC cost, profit, and profitability for each type of TCC auction for the two categories of TCC paths. The profitability is measured by the total TCC profit as a percentage of total TCC cost.

Figure A-66: TCC Cost and Profit by Auction Round and Path Type

Winter 2020/21 and Summer 2021 Capability Periods



Inter-Zone	Cost ($ M)	Profit ($ M)	Profit as a % of Cost
One Year	$47	$25	53%
Six-Mth: Winter	$64	$18	28%
Six-Mth: Summer	$41	$18	43%
Monthly: Winter	$1	-$0.3	-28%
Monthly: Summer	-$3	$0.3	-9%
Total	$150	$60	40%

Intra-Zone	Cost ($ M)	Profit ($ M)	Profit as a % of Cost
One Year	$22	-$1	-3%
Six-Mth: Winter	$16	$1	7%
Six-Mth: Summer	$50	$5	10%
Monthly: Winter	$2	$1	24%
Monthly: Summer	$12	-$1	-8%
Total	$102	$5	5%

Table A-5 & Table A-6: 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 2020/21 and Summer 2021 Capability Periods (i.e., the 12-month period from November 2020 through October 2021). 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-5: TCC Cost by Path
Winter 2020/21 and Summer 2021 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	$51	-$35	-$5	-$1	$0	$0	$10	$0	$0	$0	$0	-$1	$0	$0	$0	$20
GENESE	$5	$0	$5	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$9
CENTRL	$26	-$1	$11	$0	-$4	$1	$31	$0	$0	$0	$0	$0	$0	$0	$1	$63
MHK VL	$8	-$1	$2	-$11	-$1	$2	$1	$0	$0	$0	$0	$0	-$1	$4	$0	$3
NORTH	$0	$1	$19	$20	$0	$0	$0	$0	$0	$0	$0	$0	$1	$0	$0	$42
CAPITL	$0	$0	-$5	-$3	$0	$32	-$13	-$2	-$5	$0	$0	$0	$0	-$2	$0	$1
HUD VL	-$1	$0	-$3	$0	$0	$19	$1	$3	$4	$17	$0	$0	$0	$27	-$1	$66
MILLWD	$0	$0	$0	$0	$0	$0	-$1	$0	$0	$0	$0	$0	$0	$0	$0	-$1
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	-$1	$9	$1	$0	$0	$0	$0	$8
LONGIL	$0	$0	$0	-$1	$0	$0	$0	$0	-$1	-$1	$10	$0	$0	$0	$0	$7
O H	$3	$3	$0	$0	$0	$0	$2	$0	$0	$0	$0	$0	$0	$0	$0	$8
H Q	$0	$0	$1	$18	-$1	$0	$0	$0	$0	$0	$0	$0	-$1	$0	$0	$16
NPX	$0	$0	$0	$0	$0	$0	-$6	$0	$0	$0	$0	$0	$0	$0	$0	-$6
PJM	-$1	$0	-$4	-$1	$0	$0	$19	$1	$1	$1	$0	$0	$0	$0	$0	$15
Total	**$90**	**-$33**	**$19**	**$20**	**-$6**	**$54**	**$40**	**$2**	**-$1**	**$26**	**$13**	**-$1**	**-$1**	**$30**	**$0**	**$253**

Table A-6: TCC Profit by Path
Winter 2020/21 and Summer 2021 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	-$20	$12	$2	$0	$0	$0	$16	$0	$0	$0	$0	$1	$0	$0	$0	$12
GENESE	-$2	$1	-$1	$0	$0	$0	$0	$0	$0	$0	$0	$1	$0	$0	$0	-$1
CENTRL	-$11	$0	$3	$0	-$1	$0	$15	$0	$0	$0	$0	$0	$0	$0	$0	$6
MHK VL	-$3	$1	$0	-$10	$0	$1	$0	$0	$0	$0	$0	$0	$0	$3	$0	-$8
NORTH	$0	$1	$9	$11	$0	$0	$0	$0	$0	$0	$0	$0	$1	$0	$0	$22
CAPITL	$0	$0	-$3	-$1	$0	$10	-$7	-$1	-$2	$0	$0	$0	$0	$0	$0	-$4
HUD VL	-$1	$0	-$2	$0	$0	$8	$1	$0	$0	-$6	$0	$0	$0	$2	-$1	$1
MILLWD	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$1
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	$1	$0	$0	$0	$0	$2	$0	$0	$0	$0	$4
LONGIL	$0	$0	$0	$0	$0	$0	$0	$0	-$1	-$1	$20	$0	$0	$0	$0	$16
O H	-$2	-$1	$0	$0	$0	$0	$1	$0	$0	$0	$0	$0	$0	$0	$0	-$1
H Q	$0	$0	$0	$9	-$1	$0	$0	$0	$0	$0	$0	$0	-$1	$0	$0	$8
NPX	$0	$0	$0	$0	$0	$0	-$1	$0	$0	$0	$0	$0	$0	$0	$0	-$1
PJM	-$6	$0	-$1	$0	$0	$0	$19	$1	$1	$0	$0	$0	$0	$0	$0	$13
Total	**-$46**	**$15**	**$7**	**$9**	**-$3**	**$20**	**$44**	**$0**	**-$2**	**-$8**	**$22**	**$1**	**$0**	**$6**	**-$1**	**$66**

J. Potential Design of Financial Transmission Rights for PAR Operation

This subsection describes how a financial right could be created to compensate ConEd if the lines between NYC and Long Island were scheduled efficiently (rather than according to a fixed schedule) in accordance with Recommendation #2012-8, which is described in Section XI. An efficient financial right should compensate ConEd: (a) in accordance with the marginal production cost savings that result from efficient scheduling, and (b) in a manner that is revenue adequate such that the financial right should not result in any uplift for NYISO customers. Note, this new financial transmission right would not alter the TCCs possessed by any market party.

Concept for Financial Transmission Right

An efficient financial right should compensate ConEd for the quantity of congestion relief provided at a price that reflects the marginal cost of relieving congestion on each flow gate in the day-ahead and real-time markets. These are the same principles upon which generators are paid and load customers are charged. Hence, a transmission right holder should be paid:

DAM Payment =

$$\sum_{l=901,903}\left([DAM\ MW_l - TCC\ MW_l] \times \sum_{c=constraint}[-DAM\ SF_{l,c} \times DAM\ SP_c]\right)$$

RTM Payment =

$$\sum_{l=901,903}\left([RTM\ MW_l - DAM\ MW_l] \times \sum_{c=constraint}[-RTM\ SF_{l,c} \times RTM\ SP_c]\right)$$

Total Payment = DAM Payment + RTM Payment, where a negative payment would result in a charge to ConEd. To illustrate, suppose there is congestion in the DAM on the interface from upstate to Long Island (Y50 Line), from upstate to NYC (Dunwoodie), and into the Valley Stream load pocket (262 Line) while the 901 Line flows are reduced below the contract amount:

- TCC MW_{901} = 96 MW
- DAM MW_{901} = 60 MW
- DAM SP_{Y50} = \$10/MWh
- DAM $SP_{Dunwoodie}$ = \$5/MWh
- DAM SP_{262} = \$15/MWh
- DAM $SF_{901,\ Y50}$ = 100%
- DAM $SF_{901,\ Dunwoodie}$ = -100%
- DAM $SF_{901,\ 262}$ = 100%
- DAM $Payment_{901}$ = \$720 per hour = (60 MW – 96 MW) x {(-100% x \$10/MWh) + (100% x \$5/MWh) + (-100% x \$15/MWh)}

Since DAM payments are made for deviations from the TCC modeling assumptions, the new financial transmission right would not alter the TCCs possessed by any market party.

Revenue Adequacy

Just as the LBMP compensation to generators is generally revenue adequate, the new financial transmission right would also be revenue adequate. This is illustrated by the following scenarios:

- 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	Upstate	$25	10000	13000	$250,000	$325,000
Payments	NYC	$30	4000	1880	$120,000	$56,400
	Valley Stream	$50	350	170	$17,500	$8,500
	Rest of Long Is.	$35	2500	1800	$87,500	$63,000
	Total		16850	16850	$475,000	$452,900
	Net (Gen minus Load)			0		$22,100

	Interface	Shadow Price	Interface Flow	Congestion Revenue
Transmission	Dunwoodie	$5	2000	$10,000
Revenue	Y50	$10	1000	$10,000
	262 Line	$15	300	$4,500
	901 Line Contract	-$20	100	-$2,000
	901 Line Adjust	-$20	20	-$400
	Total			$22,100
	DAMCR (Gen minus Load minus Congestion)			$0

IV. EXTERNAL INTERFACE SCHEDULING

New York imports a substantial amount of power from four adjacent control areas: New England, PJM, Ontario, and Quebec. In addition to the four primary interfaces with adjacent regions, Long Island and New York City connect directly to PJM and New England across five controllable lines: the Cross Sound Cable, the 1385 Line, the Linden VFT Line, the HTP Line, and the Neptune Cable. The controllable lines are collectively able to import nearly 2.2 GW directly to downstate areas.[297,298] 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.

297 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.

298 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-67 to Figure A-70 : 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 2020 and 2021. 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-67, the primary interfaces with Quebec and New England in Figure A-68, and the controllable lines connecting Long Island and New York City with PJM and New England in Figure A-69 and Figure A-70.

Figure A-67: Monthly Average Net Imports from Ontario and PJM
2020 – 2021

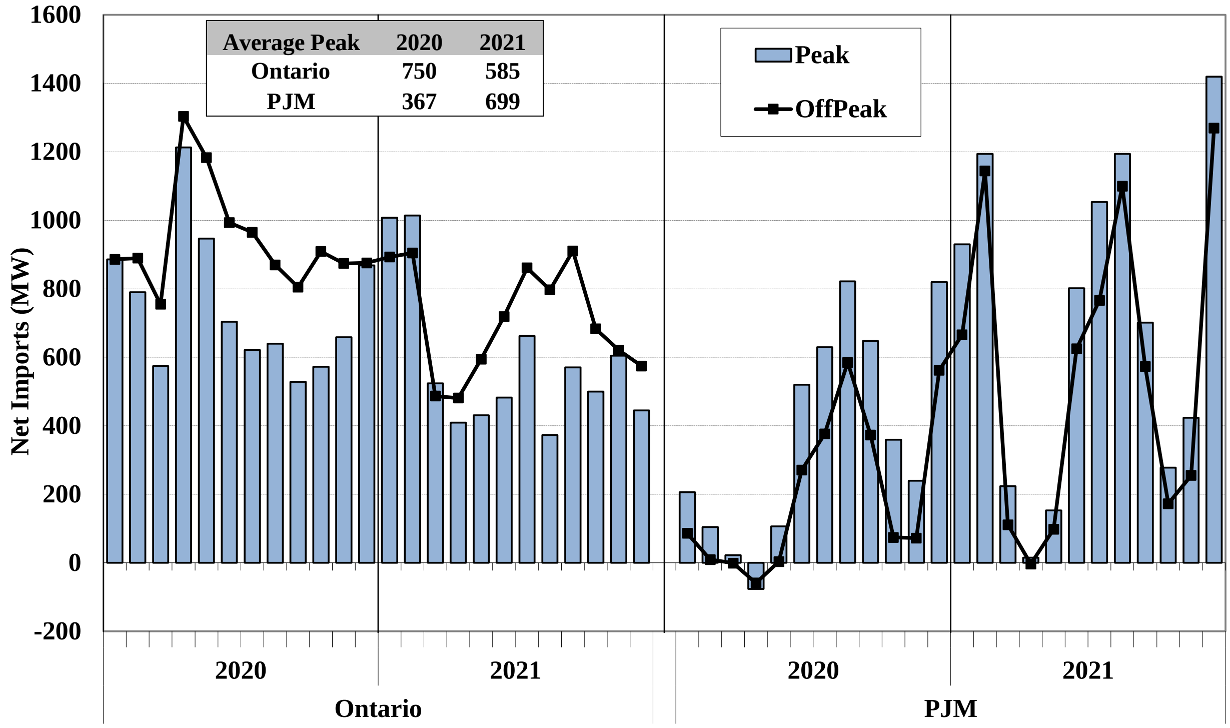


Figure A-68: Monthly Average Net Imports from Quebec and New England
2020 – 2021

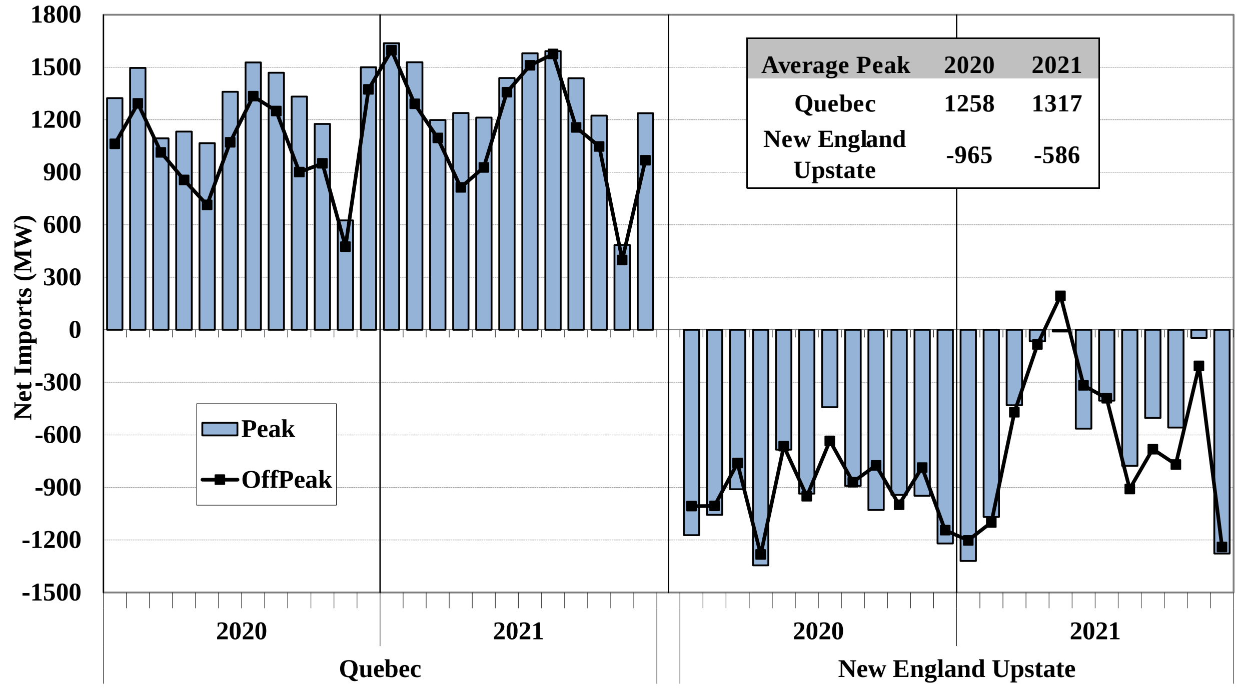


Figure A-69: Monthly Average Net Imports into New York City
2020 – 2021

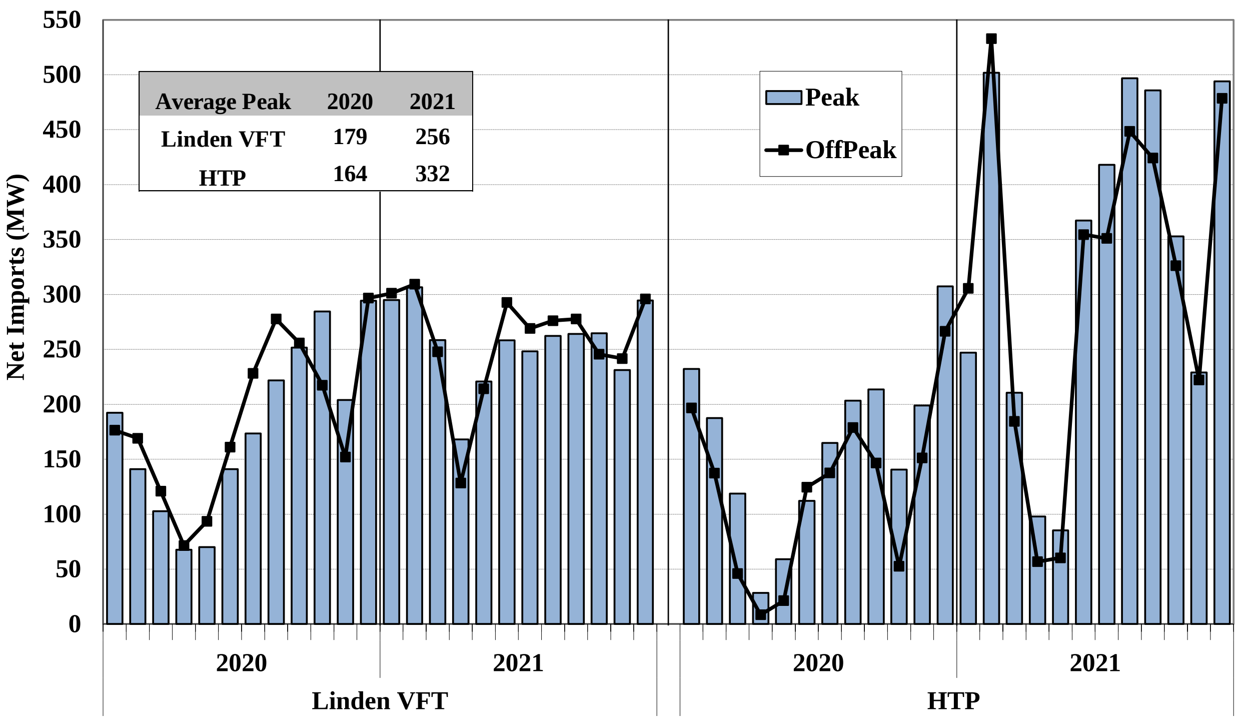
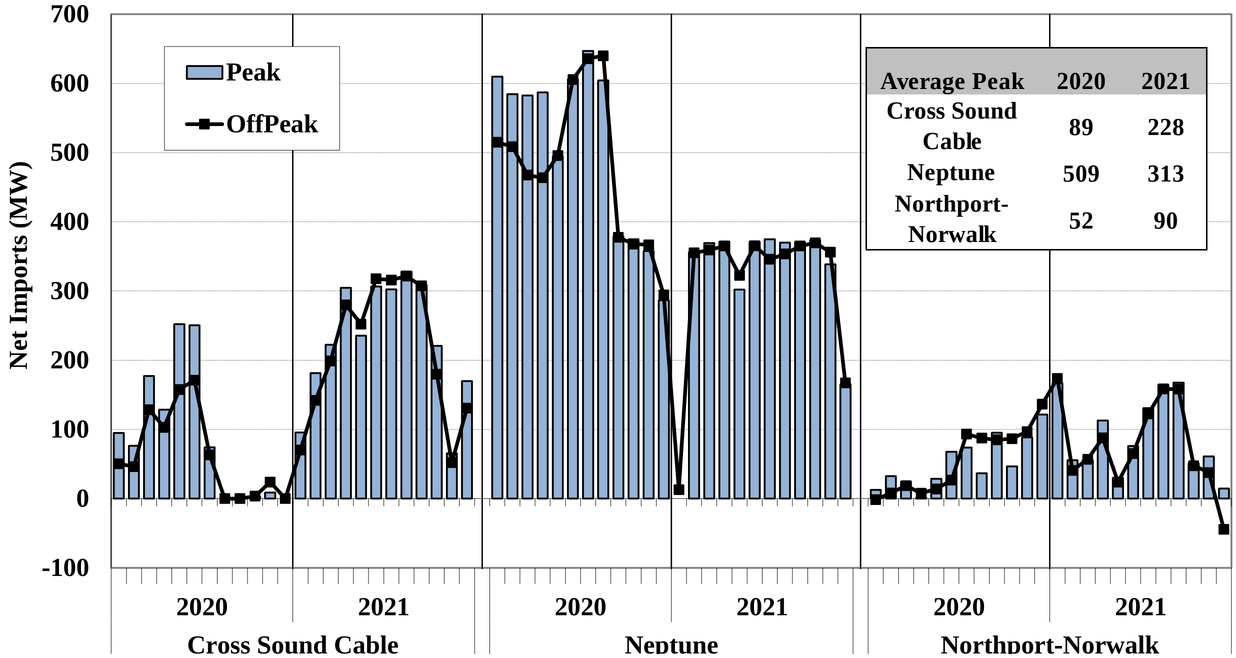


Figure A-70: Monthly Average Net Imports into Long Island
2020 – 2021



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.

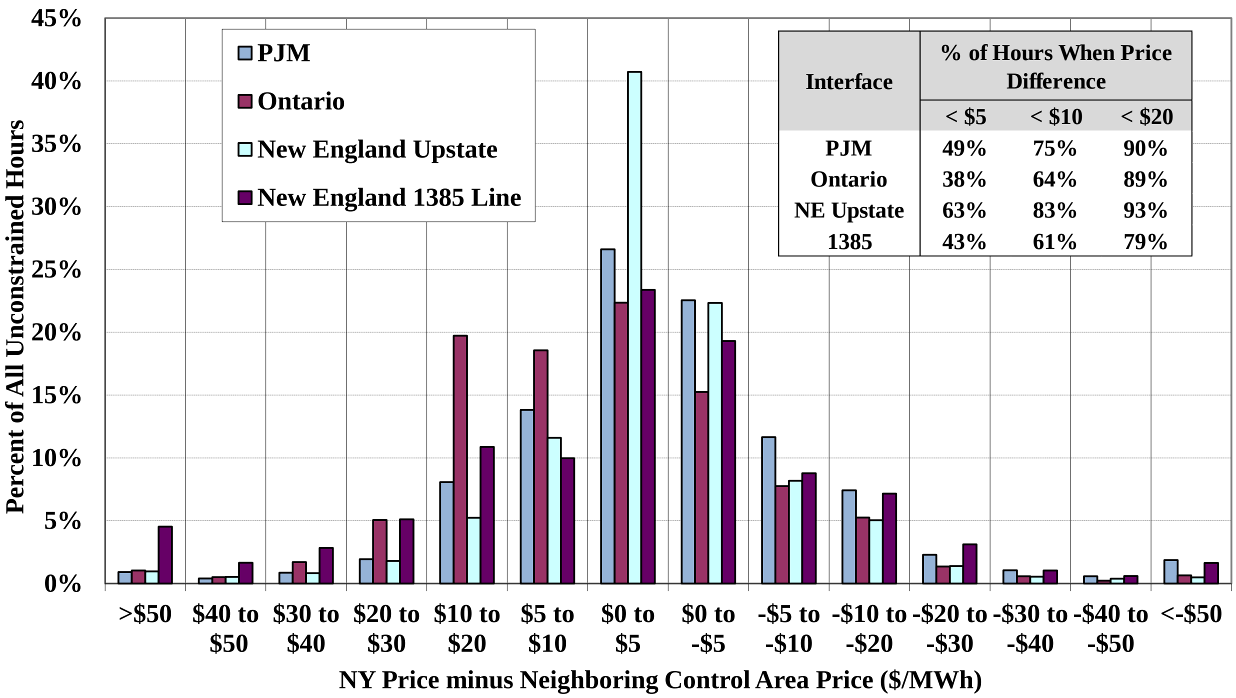
- The risks associated with curtailment and congestion reduce participants' incentives to schedule external transactions when expected price differences are small.

Figure A-71: Price Convergence Between New York and Adjacent Markets

Figure A-71 evaluates scheduling between New York and adjacent RTO markets across interfaces with open access scheduling. The Neptune Cable, the Linden VFT Line, the HTP Line, and the Cross Sound Cable are omitted because these are Designated Scheduled Lines, which have alternate systems to allocate transmission reservations. 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-71 summarizes price differences between New York and neighboring markets during unconstrained hours in 2021. 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.[299] In the figure, the horizontal axis shows the range of price differences between New York and the adjacent control areas at the border. The heights of the bars represent the fraction of hours in each price difference category.

Figure A-71: Price Convergence Between New York and Adjacent Markets
Unconstrained Hours in Real-Time Market, 2021



299 In these hours, prices in neighboring RTOs (i.e., prices at the NYISO proxy in each RTO market) reflect transmission constraints in those markets.

Table A-7: Efficiency of Inter-Market Scheduling

Table A-7 evaluates the consistency of the direction of external transaction scheduling and price differences between New York and New England, PJM, and Ontario during 2021. 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.[300]

- 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. [301]

- 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.[302]

Table A-7 evaluates the efficiency of the hourly net scheduled interchange rather than of individual transactions. Individual transactions may be scheduled in the inefficient direction, but

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300 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.

301 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.

302 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.

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-7: Efficiency of Inter-Market Scheduling
Over Primary Interfaces and Scheduled Lines – 2021

	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	-608	$1.90	43%	-$6	18	$1.68	55%	$4
Ontario	695	$6.02	79%	$44	-46	$5.46	50%	-$1
PJM	571	$0.27	68%	$12	24	-$0.07	59%	$3
Controllable Ties								
1385 Line	96	$2.68	74%	$4	-12	$1.80	52%	$3
Cross Sound Cable	215	$10.00	81%	$21	6	$10.92	52%	$1
Neptune	341	$16.73	96%	$37	-4	$18.32	33%	$1
HTP	244	$5.66	92%	$13	70	$5.28	74%	$4
Linden VFT	187	$6.64	94%	$10	59	$6.49	77%	$3

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-72: Bidding Patterns of CTS at the Primary PJM and NE Interfaces

Figure A-72 shows the average amount of CTS transactions offered and scheduled at the primary PJM and New England interfaces during peak hours (i.e., HB 7 to 22) in each month of 2021. 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.[303] Bids that are offered below -\$10/MWh or above \$20/MWh are considered price insensitive for this analysis.

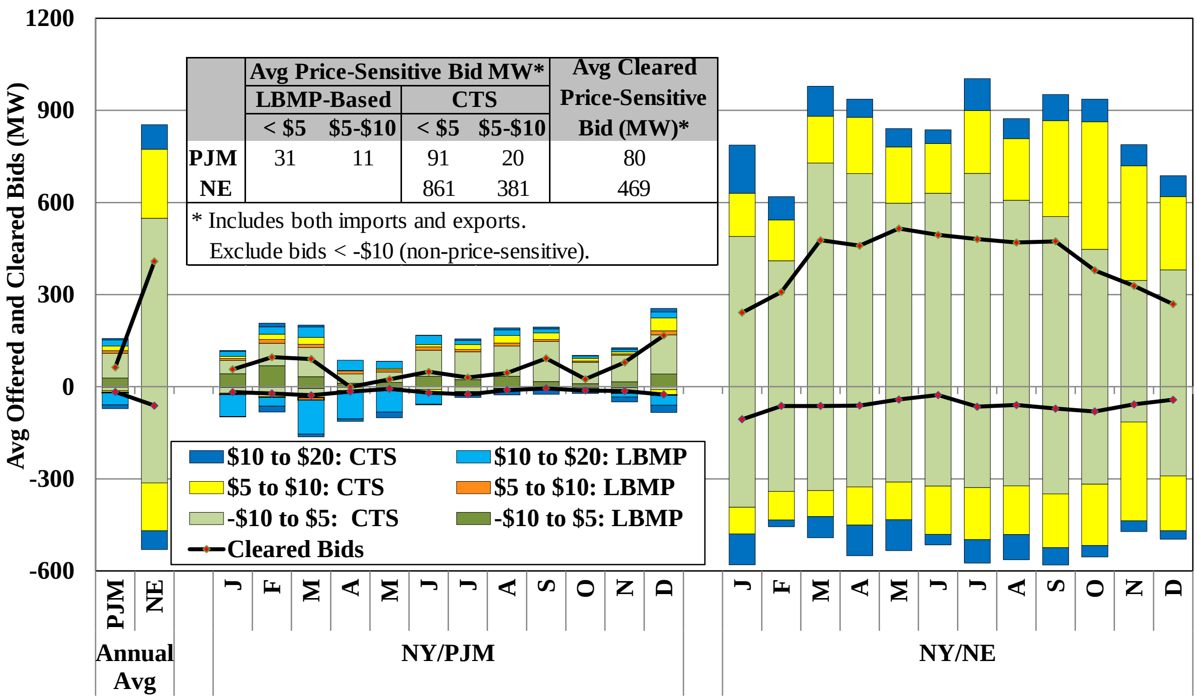
Traditional LBMP-based bids and CTS bids are allowed at the PJM interface (unlike the primary New England interface where only CTS bids are allowed). To make a fair comparison between the two primary interfaces, LBMP-based bids at the PJM interface are converted to equivalent CTS bids and are shown in the figure as well. The equivalent CTS bids are constructed as:

- Equivalent CTS bid to import = LBMP-based import offer – PJM Forecast Price
- Equivalent CTS bid to export = PJM Forecast Price – LBMP-based export bid

The two black lines in the chart indicate the average scheduled price-sensitive imports and exports (including both CTS and LBMP-based bids) in each month. The table in the figure summarizes for the two CTS-enabled interfaces: a) the average amount of price-sensitive bids with low offer prices, which are either less than \$5/MWh or between \$5 and \$10/MWh; and b) the average cleared price-sensitive bids in 2021.

Figure A-72: Price-Sensitive Real-Time Transaction Bids and Offers by Month

PJM and NE Primary Interfaces, 2021



303 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.

Figure A-73: Transaction Profitability at the Primary PJM and NE Interfaces

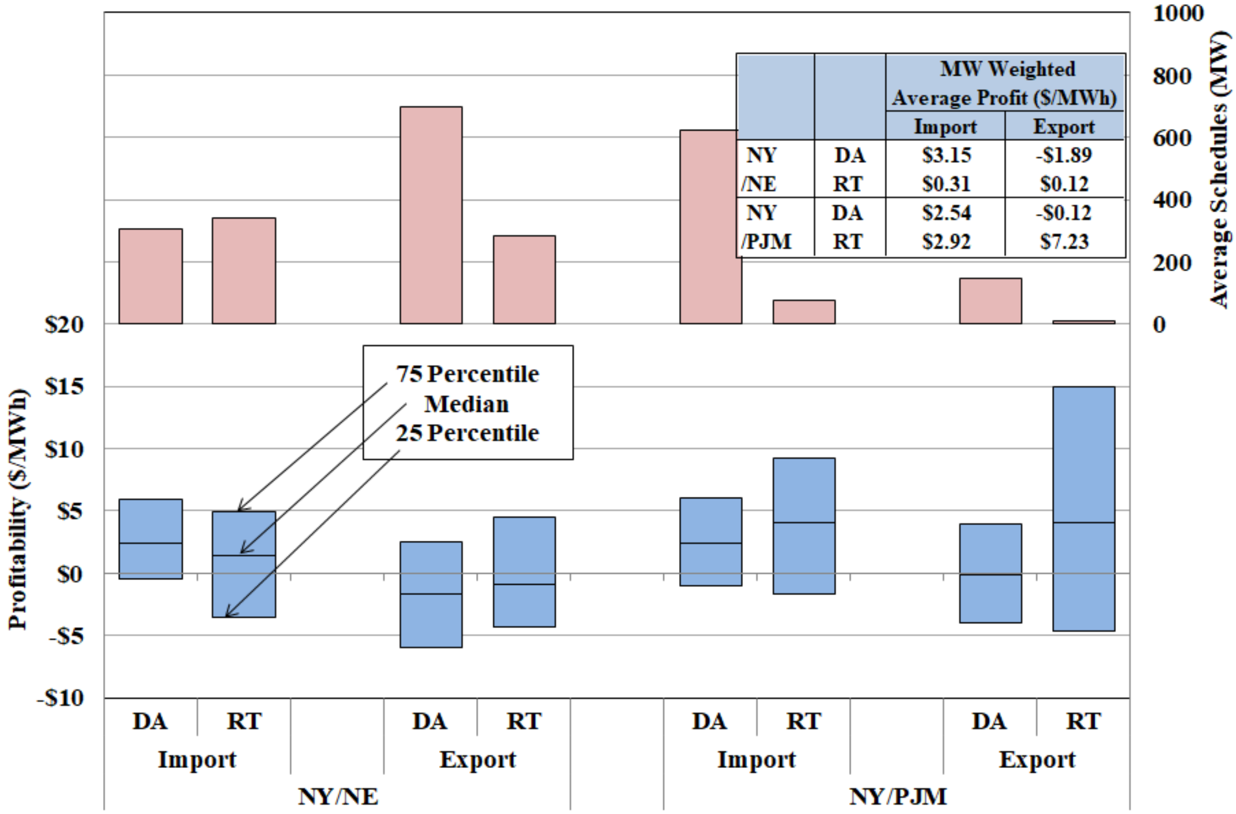
The second analysis examines the profitability of scheduled transactions at the two CTS-enabled interfaces. In the bottom portion of Figure A-73, the column bars indicate the profitability spread of the middle two quartiles (i.e, 25 to 75 percentile) in 2021. The line inside each bar denotes the median 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 2021 and the inset table summarizes the annual average profit.

Figure A-73: Profitability of Scheduled External Transactions
PJM and NE Primary Interfaces, 2021



		MW Weighted Average Profit ($/MWh)	
		Import	Export
NY /NE	DA	$3.15	-$1.89
	RT	$0.31	$0.12
NY /PJM	DA	$2.54	-$0.12
	RT	$2.92	$7.23

Table A-8: 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. [304]

Table A-8 examines the performance of the intra-hour scheduling process under CTS at the primary PJM and New England interfaces in 2021. 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.
    - o 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.[305]
    - o 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,

304 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.

305 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 310.

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. [306]

- Other Unrealized Savings – This measures production cost savings that are not realized once the following factors are taken into account:
  - Real-time Curtailment[307] - 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[308] - 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-75). 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[309,310] – This is equal to (Projected Savings – Net Over-Projected Savings - Unrealized Savings).

306 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.

307 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).

308 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).

309 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).

310 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

- Interface Prices – These show actual real-time prices and forecasted prices at the time of RTC scheduling.

- Price Forecast Errors – These measure the performance of price forecasting by showing the average difference and the average absolute difference between the actual and forecasted prices on both sides of the interfaces.

To examine how price forecast errors affected efficiency gains, these numbers are shown separately for the intervals during which forecast errors are less than $20/MWh and the intervals during which forecast errors exceed $20/MWh.

Table A-8: Efficiency of Intra-Hour Scheduling Under CTS
Primary PJM and New England Interfaces, 2021

			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 > $20	Total	
% of All Intervals w/ Adjustment			74%	9%	**83%**		38%	10%	**48%**	
Average Flow Adjustment (MW)	Net Imports		10	-11	**8**		12	-16	**6**	
	Gross		112	166	**117**		59	85	**64**	
Production Cost Savings ($ Million)	Projected at Scheduling Time		$7.1	$3.8	**$10.9**		$1.2	$3.0	**$4.2**	
	Net Over-Projection by:	NY	-$0.4	-$1.0	**-$1.4**		-$0.2	-$0.5	**-$0.6**	
		NE or PJM	$0.2	$0.2	**$0.4**		-$0.2	-$2.5	**-$2.7**	
	Other Unrealized Savings		-$0.2	-$0.3	**-$0.5**		$0.0	$0.2	**$0.2**	
	Actual Savings		$6.7	$2.7	**$9.4**		$0.8	$0.3	**$1.0**	
Interface Prices ($/MWh)	NY	Actual	$36.41	$76.77	**$40.76**	**$40.85**	$33.75	$60.76	**$39.41**	**$34.89**
		Forecast	$37.70	$71.48	**$41.34**	**$41.20**	$34.86	$57.90	**$39.69**	**$35.12**
	NE or PJM	Actual	$36.28	$73.24	**$40.26**	**$43.21**	$32.23	$69.99	**$40.14**	**$35.79**
		Forecast	$35.09	$65.83	**$38.40**	**$41.38**	$34.16	$84.35	**$44.67**	**$38.88**
Price Forecast Errors ($/MWh)	NY	Fcst. - Act.	$1.30	-$5.29	**$0.59**	**$0.34**	$1.12	-$2.86	**$0.28**	**$0.23**
		Abs. Val.	$3.41	$50.16	**$8.45**	**$8.18**	$3.57	$25.12	**$8.08**	**$6.00**
	NE or PJM	Fcst. - Act.	-$1.19	-$7.40	**-$1.86**	**-$1.83**	$1.93	$14.35	**$4.53**	**$3.09**
		Abs. Val.	$3.19	$21.69	**$5.18**	**$5.49**	$4.45	$62.57	**$16.62**	**$12.22**

For Adjustment Intervals Only | For All Intervals

Figure A-74 & Figure A-75: Price Forecast Errors Under CTS

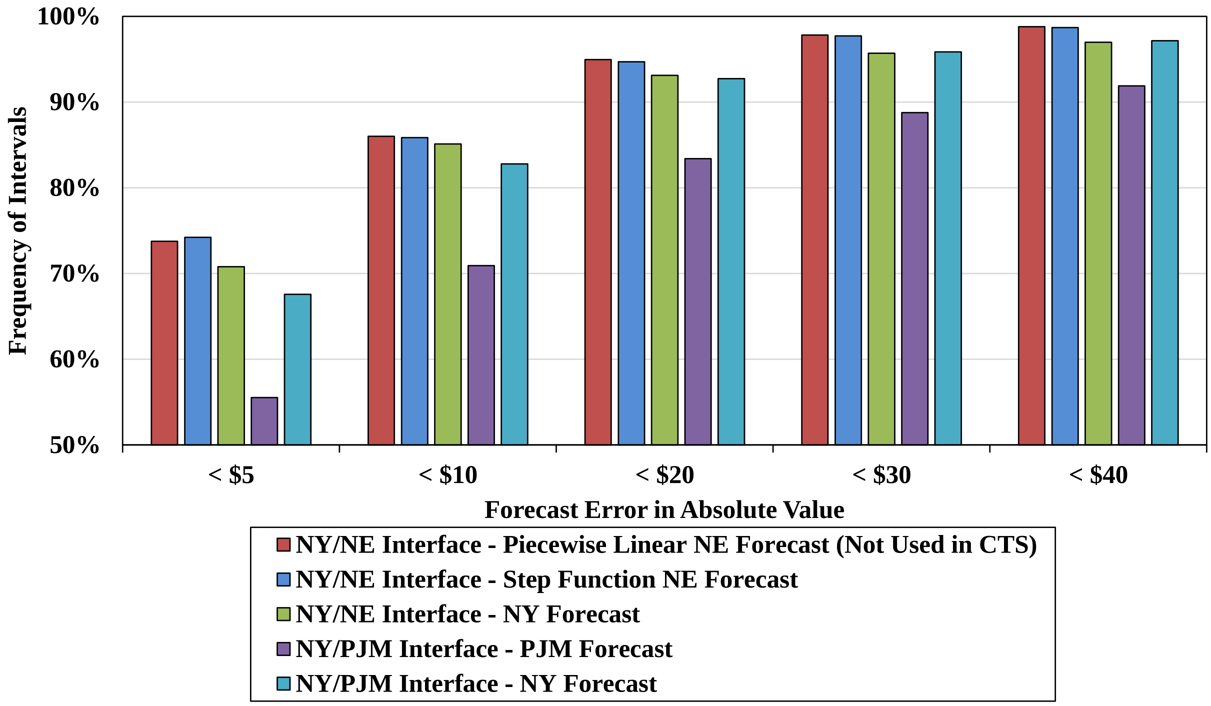
The next analysis compares the performance of price forecasting by the three ISOs in the CTS process. Figure A-74 shows the cumulative distribution of forecasting errors in 2021. The price forecast error in each 15-minute period is measured as the absolute value of the difference between the forecast 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)

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.

based on the step-function curve that the NYISO model uses to approximate the piece-wise linear curve.

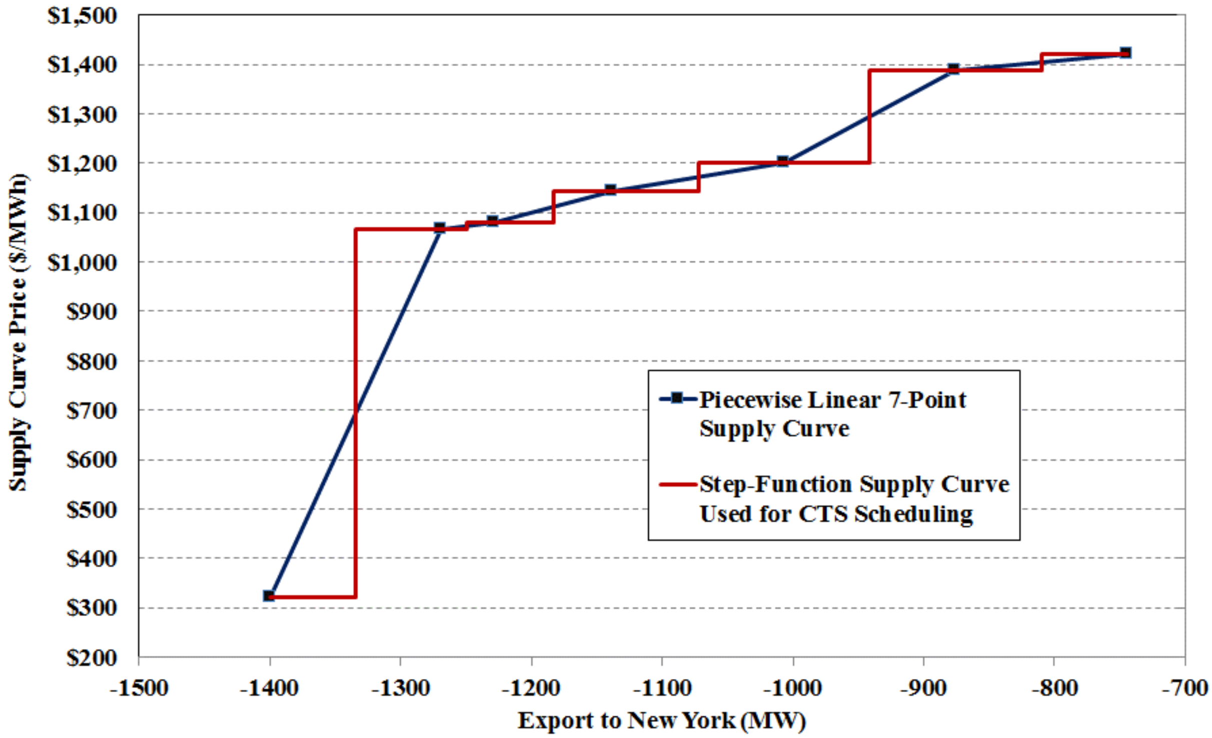
Figure A-75 illustrates this with example curves. [311] The blue squares in the figure show the seven price/quantity pairs that are produced by the ISO-NE price forecast engine (CTSPE). The blue line connecting these seven squares represents a piecewise linear supply curve at the New England border. The red step-function curve is an approximation of the piecewise linear curve and is actually used in RTC for scheduling CTS transactions at the New England border.

Figure A-74: Distribution of Price Forecast Errors Under CTS
NE and PJM Primary Interfaces, 2021



311 The two curves are forecasted supply curves used in the market on January 5, 2016.

Figure A-75: Example of Supply Curve Produced by ISO-NE and Used by RTC



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-76 & Figure A-77: Patterns in Differences between RTC Forecast Prices and RTD Prices

Figure A-76 shows a histogram of the resulting differences in 2021 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-76: Histogram of Differences Between RTC and RTD Prices and Schedules
2021

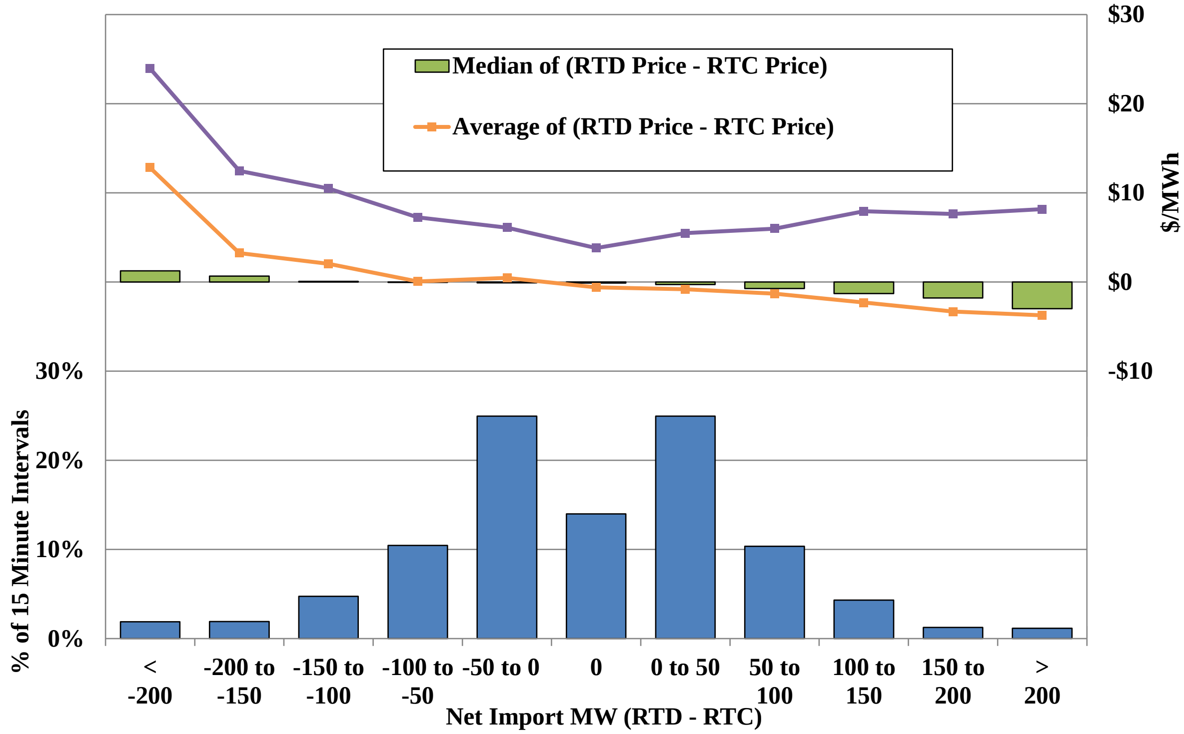


Figure A-77 summarizes these pricing and scheduling differences by time of day. The stacked bars in the lower portion of the figure show the frequency, direction, and magnitude of differences between RTC and RTD net import levels in 100-and-above MW tranches. The upper portion of the figure summarizes 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-77: Differences Between RTC and RTD Prices and Schedules by Time of Day
2021

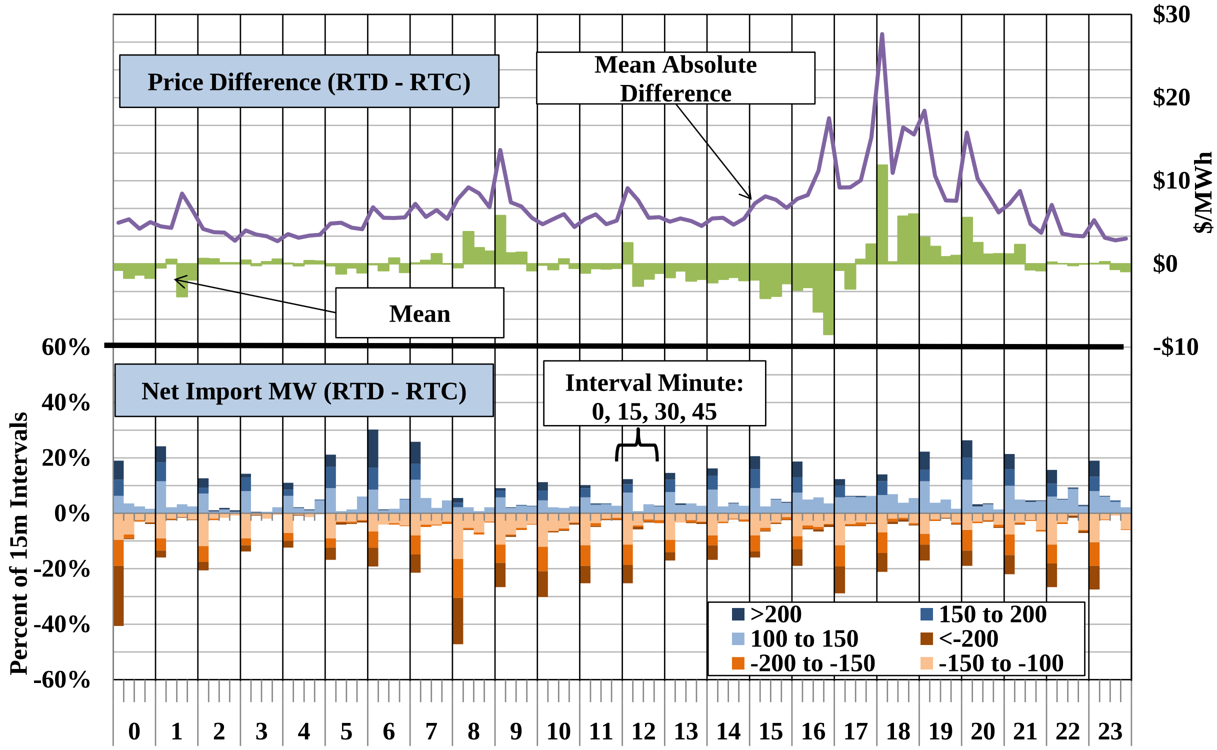


Figure A-78 to Figure A-81: Forecast Assumptions Used by RTC to Schedule CTS Transactions and Their Price Impact

Figure A-78 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-78: Illustration of External Transaction Ramp Profiles in RTC and RTD

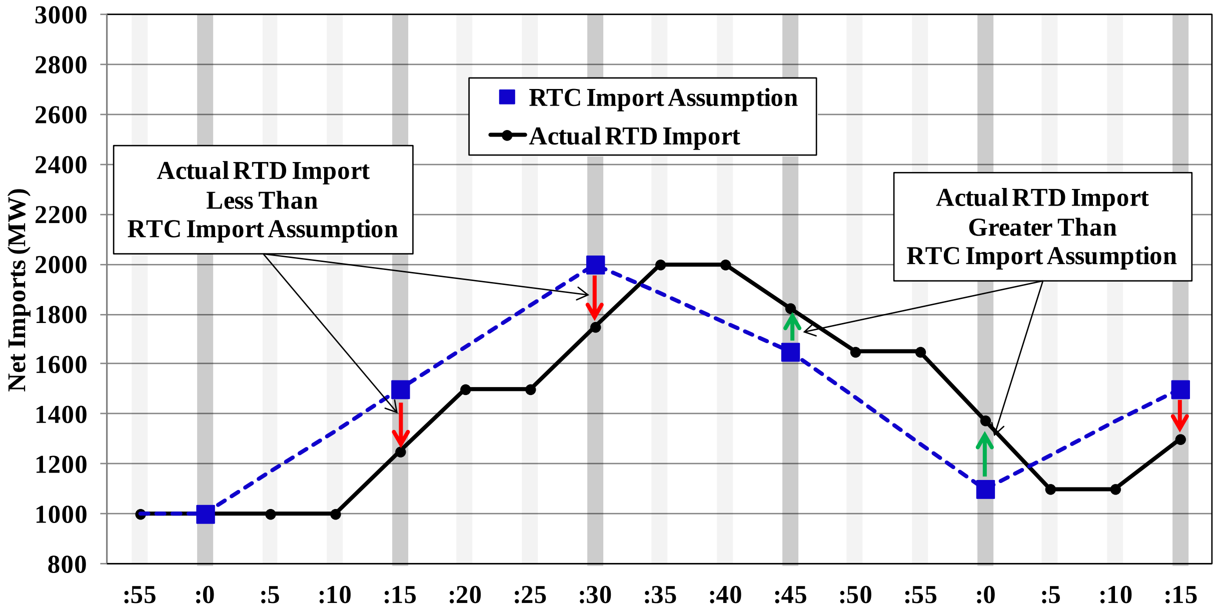


Figure A-79 to Figure A-81 provide the results of our systematic evaluation of factors that lead to inconsistent results in RTC and RTD. This evaluation assesses the magnitude of the contribution of various factors using a metric that is described below. An important feature of this metric is that it 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). [312]

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-

312 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.

differential between RTC and RTD with the corresponding price-differential for resources that are explicitly considered and priced by the real-time models.

For generation resource, external transaction, or load i, our inconsistency metric is calculated as follows:

$$Metric_i = (NetInjectionMW_{i,RTC} – NetInjectionMW_{i,RTD}) * (Price_{i,RTC} – Price_{i,RTD})$$ [313]

Hence, for the load forecast in the example above, the metric is:

$$Metric_{load} = 100\ MW * (\$45/MWh – \$65/MWh) = -\$2,000/hour$$

For the high-cost generator in the example above, the metric is:

$$Metric_{generator} = -100\ MW * (\$45/MWh – \$65/MWh) = +\$2,000/hour$$

For the foregone CTS imports in the example above, the metric is:

$$Metric_{import} = 0\ MW * (\$45/MWh – \$65/MWh) = \$0/hour$$

The metric produces a negative value for the load forecast, indicating that the under-forecast of load was a “detrimental” factor that contributed to the divergence between the RTC forecast price and the actual RTD price. The metric produces a positive value for the generator that responded to the need for additional supply in RTD, indicating that the generator’s response was a “beneficial” factor that helped limit the divergence between the RTC forecast price and the actual RTD price. The metric produces a zero value for the foregone CTS imports, recognizing that the divergence was not caused by the CTS imports not being scheduled, but rather that their not being scheduled was the result of poor forecasting.

For PAR-controlled line i, our inconsistency metric is calculated across binding constraints c:

$$Metric_i = (FlowMW_{i,RTC} – FlowMW_{i,RTD}) * \sum_c \{(ShadowPrice_{c,RTC} * ShiftFactor_{i,c,RTC} – ShadowPriceMW_{c,RTD} * ShiftFactor_{i,c,RTD})\}$$

Hence, for a PAR-controlled line that is capable of relieving congestion on a binding constraint, if the flow on the PAR-controlled line is higher in RTD than in RTC and the shadow price of the constraint is higher in RTD than in RTC, the metric will produce a positive value, indicating that the PAR-controlled line had a beneficial inconsistency (i.e., it helped reduce the divergence between RTC and RTD congestion prices). However, if the flow on the PAR-controlled line decreases in RTD while the shadow price is increasing, the metric will produce a negative value, indicating that the PAR-controlled line had a detrimental inconsistency (i.e., it contributed to the

313 Note, that this metric is summed across energy, operating reserves, and regulation for each resource.

divergence between RTC and RTD congestion prices). This calculation is performed for both "optimized" PARs and "non-optimized" PARs.[314]

For transmission constraints that are modeled, it is also important to quantify inconsistencies that lead to divergence between RTC and RTD. To the extent that such inconsistencies result from reductions in available transfer capability that increase congestion, the metric will produce a negative (i.e., detrimental) result. On the other hand, if inconsistencies result from an increase in transfer capability that helps ameliorate an increase in congestion, the metric will produce a positive (i.e., beneficial) result. For each limiting facility/contingency pair c, the calculation utilizes the shift factors and schedules for resources and other inputs i:

$$\text{Metric\_BindingTx}_c = \text{ShadowPrice}_{c,RTC} * \textstyle\sum_i \{\text{ShiftFactor}_{i,c,RTC} * (\text{MW}_{i,RTC} - \text{MW}_{i,RTD})\}$$
$$-\text{ShadowPrice}_{c,RTD} * \textstyle\sum_i \{\text{ShiftFactor}_{i,c,RTD} * (\text{MW}_{i,RTC} - \text{MW}_{i,RTD})\}$$

Once the metric is calculated for each optimized PAR and each binding constraint, the transmission system is divided into regions and if a particular region has optimized PARs and/or binding constraints with positive and negative values, the following adjustments are used. If the sum across all values is positive, then each positive value is multiplied by the ratio of: {(TotalGrossPositive + TotalGrossNegative)/TotalGrossPositive} and each negative value is discarded. If the sum across all values is negative, then each negative value is multiplied by the ratio of: {(TotalGrossPositive + TotalGrossNegative)/TotalGrossNegative} and each positive value is discarded. This is done because when transfer capability on one facility in a particular region is reduced, the optimization engine often increases utilization of parallel circuits, so the adjustments above are helpful in discerning whether the net effect was beneficial or detrimental.

Example 1

The following two-node example illustrates how the metrics would be calculated if a transmission line tripped after the RTC run, causing a divergence between RTC and RTD prices. Suppose, RTC forecasts:

- Load_A = 100 MW and Load_B = 200 MW;
- Three transmission lines (Lines 1, 2, and 3) with equal impedance connect A to B and the lowest rated line (Line 1) has 50 MW of capability, so the shift factor of node A on Line 1 is 0.333 (assuming node B is the reference bus);
- Gen_A produces 250 MW at a cost of \$20/MWh and Gen_B produces 50 MW at a cost of \$30/MWh; and
- Thus, in RTC, Price_A = \$20/MWh, Price_B = \$30/MWh, Flow_{AB1} on Line 1 = 50 MW, so the ShadowPrice_{AB1} = \$30/MWh.

314 A PAR is called "non-optimized" if the RTC and RTD models treat the flow as a fixed value in the optimization engine, while a PAR is called "optimized" if the optimization engines of the RTC and RTD models treat the flow as a flexible within some range.

Suppose that before RTD runs, Line 2 trips, reducing flows from Node A to Node B and requiring output from a $45/MWh generator at Node B. This will lead to the following changes:

- Only two transmission lines (Lines 1 and 3) with equal impedance connect A to B, so the shift factor of node A on Line 1 is 0.5 (assuming node B is the reference bus);
- Gen_A produces 200 MW at a cost of $20/MWh, Gen_B produces 50 MW at a cost of $30/MWh, and Gen_{B2} produces 50 MW at a cost of $45/MWh; and
- Thus, in RTD, $Price_A$ = $20/MWh, $Price_B$ = $45/MWh, $Flow_{AB1}$ on Line 1 = 50 MW, so the $ShadowPrice_{AB1}$ = $50/MWh.

In this example, the metric would be calculated as follows for each input:

- $Metric\_Load_A$ = $0 = (-100MW - -100MW) * ($20/MWh - $20/MWh)
- $Metric\_Load_B$ = $0 = (-200MW - -200MW) * ($30/MWh - $45/MWh)
- $Metric\_Gen_A$ = $0 = (250MW - 200MW) * ($20/MWh - $20/MWh)
- $Metric\_Gen_B$ = $0 = (50MW - 50MW) * ($30/MWh - $45/MWh)
- $Metric\_Gen_{B2}$ = $750/hour = (0MW - 50MW) * ($30/MWh - $45/MWh)
- Metric_BindingTx = -$750/hour = $30/MWh * 0.333 * (250MW - 200MW) – $50/MWh * 0.5 * (250MW - 200MW)
- Metric_BindingTx exhibits a negative value, indicating a detrimental factor because the divergence between RTC prices and RTD prices was caused by a reduction in transfer capability from Node A to Node B. $Metric\_Gen_{B2}$ exhibits a positive value, indicating a beneficial factor because the divergence between RTC prices and RTD prices was limited by the response of additional generation at Node B. All of the other factors have a zero value because they neither contributed to convergence or divergence between RTC and RTD prices.

Example 2

The following two-node example illustrates how the metrics would be calculated if a generator tripped after the RTC run, causing a divergence between RTC and RTD prices. Suppose, RTC forecasts:

- $Load_A$ = 100 MW and $Load_B$ = 200 MW;
- Three transmission lines (Lines 1, 2, and 3) with equal impedance connect A to B and the lowest rated line (Line 1) has 50 MW of capability, so the shift factor of node A on Line 1 is 0.333 (assuming node B is the reference bus);

- Gen_A produces 200 MW at a cost of $20/MWh and Gen_B produces 100 MW at a cost of $20/MWh; and

- Thus, in RTC, $Price_A$ = $20/MWh, $Price_B$ = $20/MWh, $Flow_{AB1}$ on Line 1 = 33.33 MW, so the $ShadowPrice_{AB1}$ = $0/MWh.

Suppose that before RTD runs, Gen_B trips, increasing flows from Node A to Node B from 100 MW to 150 MW, requiring 50 MW of additional production from Gen_A and requiring 50 MW of production from a $45/MWh generator at Node B. This will lead to the following changes:

- Gen_A produces 250 MW at a cost of $20/MWh and Gen_{B2} produces 50 MW at a cost of $45/MWh; and

- Thus, in RTD, $Price_A$ = $20/MWh, $Price_B$ = $45/MWh, $Flow_{AB1}$ on Line 1 = 50 MW, so the $ShadowPrice_{AB1}$ = $75/MWh.

In this example, the metric would be calculated as follows for each input:

- $Metric\_Load_A$ = $0 = (-100MW - -100MW) * ($20/MWh - $20/MWh)

- $Metric\_Load_B$ = $0 = (-200MW - -200MW) * ($20/MWh - $45/MWh)

- $Metric\_Gen_A$ = $0 = (200MW - 250MW) * ($20/MWh - $20/MWh)

- $Metric\_Gen_B$ = -$2,500/hour = (100MW - 0MW) * ($20/MWh - $45/MWh)

- $Metric\_Gen_{B2}$ = $1,250/hour = (0MW - 50MW) * ($20/MWh - $45/MWh)

- Metric_BindingTx = $1,250/hour = $0/MWh * 0.333 * (200MW - 250MW) – $75/MWh * 0.333 * (200MW - 250MW)

- Metric_BindingTx exhibits a positive value, indicating a beneficial factor because excess transfer capability was utilized to reduce the divergence between RTC prices and RTD prices that was caused by the generator trip at Node B. $Metric\_Gen_{B2}$ exhibits a positive value, indicating a beneficial factor because the divergence between RTC prices and RTD prices was limited by the response of additional generation at Node B. All of the other factors have a zero value because they neither contributed to convergence or divergence between RTC and RTD prices.

Categories of Factors Affecting RTC/RTD Price Divergence

RTC and RTD forecasts are based on numerous inputs. We summarize inputs that change between RTC and RTD in the following ten categories for the purposes of this analysis:

- Load Forecast Error – Combines the forecast of the load forecasting model with any upward or downward adjustment by the operator.

- Wind Forecast Error – Uses the blended value that is a weighted average of the wind forecasting model and the current telemetered value.
- External Transaction Curtailments and Checkout Failures
- Generator Forced Outages and Derates
- Generator Not Following Schedule – Includes situations where a generator's RTD schedule is affected by a ramp-constraint and where the ramp-constraint was tighter as a result of the generator not following its schedule in a previous interval.
- Generator on OOM Dispatch
- Generator Dispatch In Merit
- NY/NJ PARs and Other Non-Optimized PARs – Includes the A, 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-78.

Figure A-79 summarizes the RTC/RTD divergence metric results for detrimental factors in 2021, while Figure A-80 provides the summary for beneficial factors. Figure A-81 summarizes the beneficial and detrimental metric results for Transmission Utilization.

Figure A-79: Detrimental Factors Causing Divergence between RTC and RTD
2021

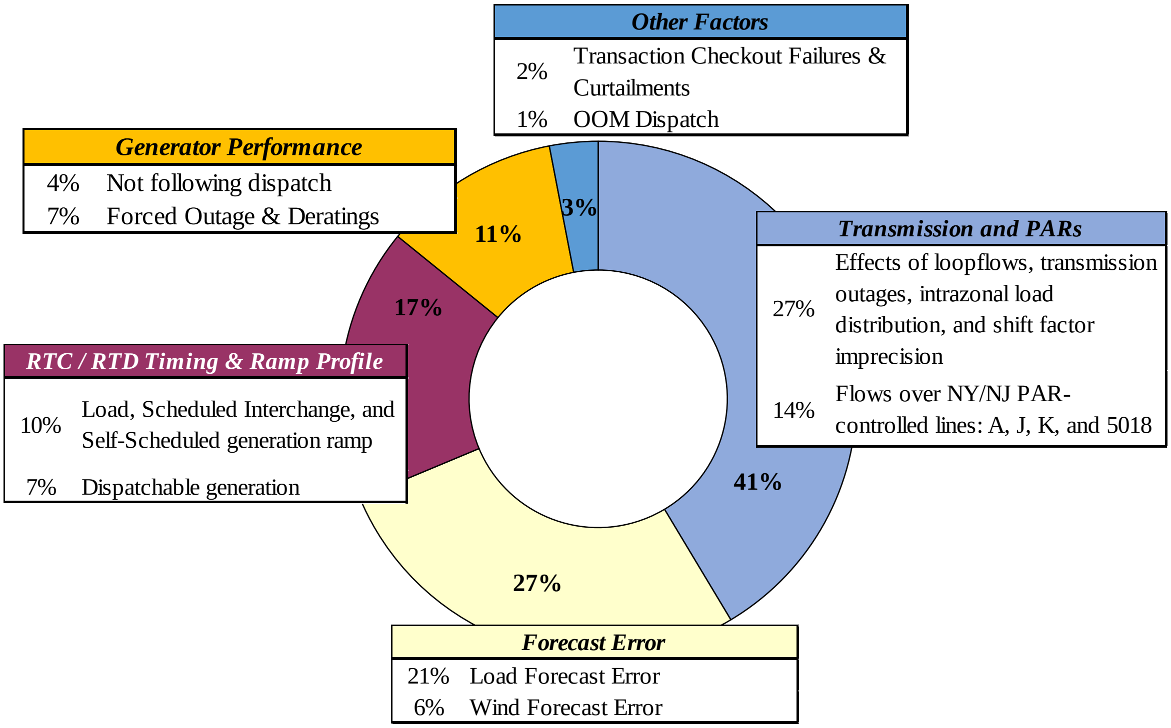
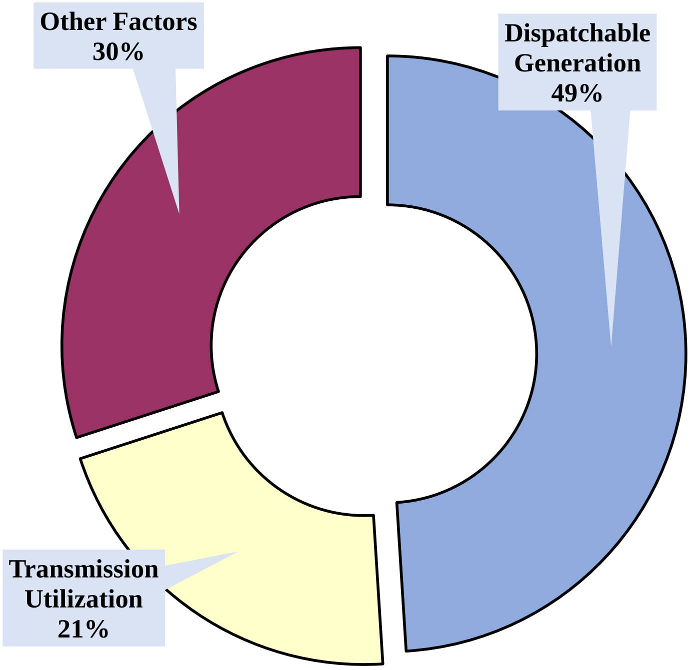
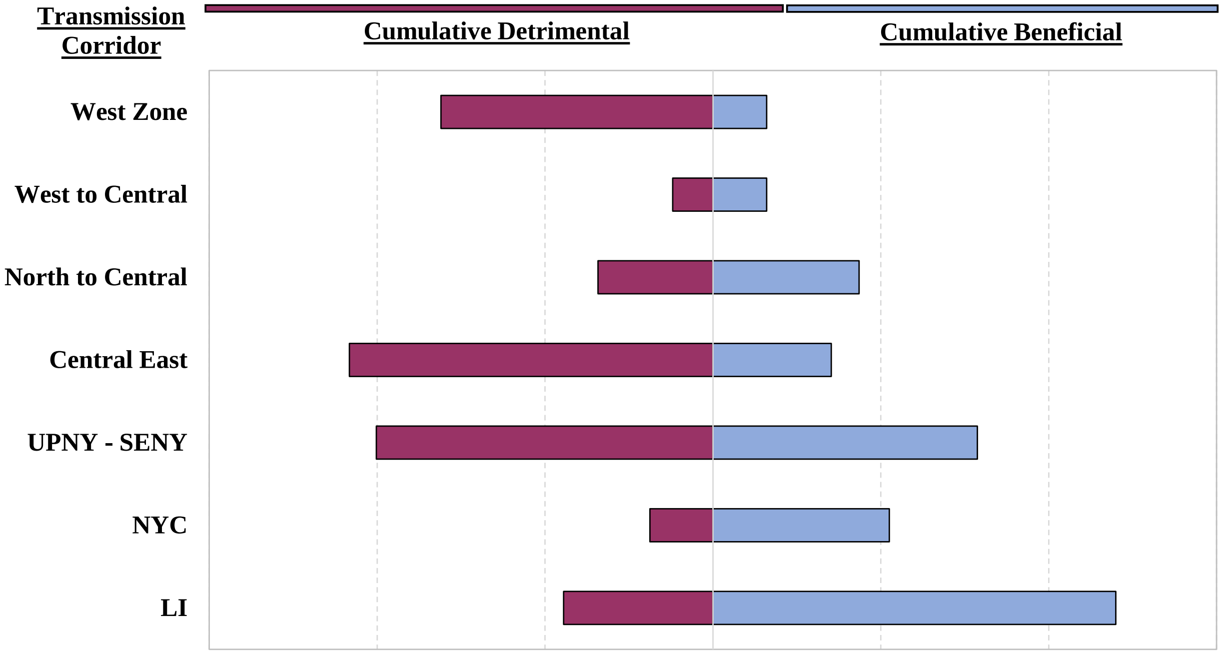


Figure A-80: Beneficial Factors Reducing Divergence between RTC and RTD
2021



"Dispatchable Generation"	
Factors for the redispatch of generators.	
"Other Factors"	
Wind Forecast Error	6%
Ramp Profile	6%
Load Forecast Error	6%
Non-optimized PARs	4%
Not-Following Dispatch	3%
Forced Outage / Derate	3%
OOM Dispatch	1%
Checkout Failures / Curtailment	1%
"Transmission Utilization"	
Includes optimized transmission and PAR operations	

Figure A-81: Effects of Network Modeling on Divergence between RTC and RTD
By Region, 2021



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 2021:

- *Efficiency of Gas Turbine Commitment* – This sub-section evaluates the consistency of real-time pricing with real-time gas turbine commitment and dispatch decisions.
- *Performance of Operating Reserve Providers* – This sub-section analyzes: a) the performance of gas turbines in responding to a signal to start-up in the real-time market; and b) how the expected performance of operating reserve providers affects the cost of congestion management in New York City.
- *M2M Coordination* – This sub-section evaluates the operation of PAR-controlled lines under market-to-market coordination ("M2M") between PJM and the NYISO.
- *Operation of Controllable Lines* – This sub-section evaluates the efficiency of real-time flows across controllable lines more generally.
- *Real-Time Transient Price Volatility* – This sub-section evaluates the factors that lead to transient price volatility in the real-time market.
- *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.

- *Potential Design for Compensating Reserve Suppliers that Provide Congestoin Relief* – This sub-section describes a modeling approach, in accordance with Recommendation #2016-1, with which reserve suppliers that provide congestion relief in New York City could be properly compensated.

A. Efficiency of Gas Turbine Commitments

The ISO schedules resources to provide energy and ancillary services using two models in real-time. First, the Real Time Dispatch model ("RTD") usually executes every five minutes, deploying resources that are flexible enough to adjust their output every five minutes. RTD also starts 10-minute units when it is economic to do so.[315] 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-

315 10-minute units can start quickly enough to provide 10-minute non-synchronous reserves.

minute units when it is economic to do so.[316] RTC also schedules bids and offers to export, import, and wheel-through power to and from other control areas.

The scheduling of energy and ancillary services is co-optimized, which is beneficial for several reasons. First, co-optimization reduces production costs by efficiently reallocating resources to provide energy and ancillary services every five minutes. Second, the market models are able to incorporate the costs of maintaining ancillary services into the price of energy by co-optimizing energy and ancillary services. This is important during periods of acute scarcity when the demand for energy and the ancillary services requirements compete for supply. Third, demand curves rationalize the pricing of energy and ancillary services during shortage periods by establishing a limit on the costs that can be incurred to maintain reserves and regulation. This also provides an efficient means of setting prices during shortage conditions. The use of demand curves during shortage conditions is discussed further in subsection F.

Convergence between RTC and RTD is important because a lack of convergence can result in uneconomic commitment of generation, particularly of gas turbines, and inefficient scheduling of external transactions. When RTC commits or schedules excess resources, it leads to depressed real-time prices and increased uplift costs. Alternatively, when RTC commits insufficient resources, it leads to unnecessary scarcity and price spikes. This subsection evaluates the efficiency of real-time commitment and scheduling of gas turbines.

Figure A-82: Efficiency of Gas Turbine Commitment

Figure A-82 evaluates the efficiency of gas turbine commitment (including both fixed-block and dispatchable GTs) from 2019 to 2021. The evaluation focuses on economic commitments that are made by RTC, RTD, or RTD-CAM, [317] excluding self schedules and OOM commitments made by operators. The bars in the figure show the portion of the total as-bid cost of the GT that is not recouped through LBMP revenues over the unit's initial commitment period (up to one hour).The total cost includes *Minimum Generation* cost (if applicable), *Incremental Energy* cost, and *Start-Up* cost amortized over the initial commitment period.

When the commitment decisions are efficient, the costs of committed gas turbines are usually lower than the energy revenues they receive based on real-time LBMP. However, an efficient commitment can lead the total production cost to be not fully compensated by the real-time LBMP for the following reasons:

- The commitment decision is often made based on forecasted conditions in RTC or RTD, while the unit is compensated with LBMPs based on real-time conditions.

316 30-minute units can start quickly enough to provide 30-minute non-synchronous reserves, but not quickly enough to provide 10-minute reserves.

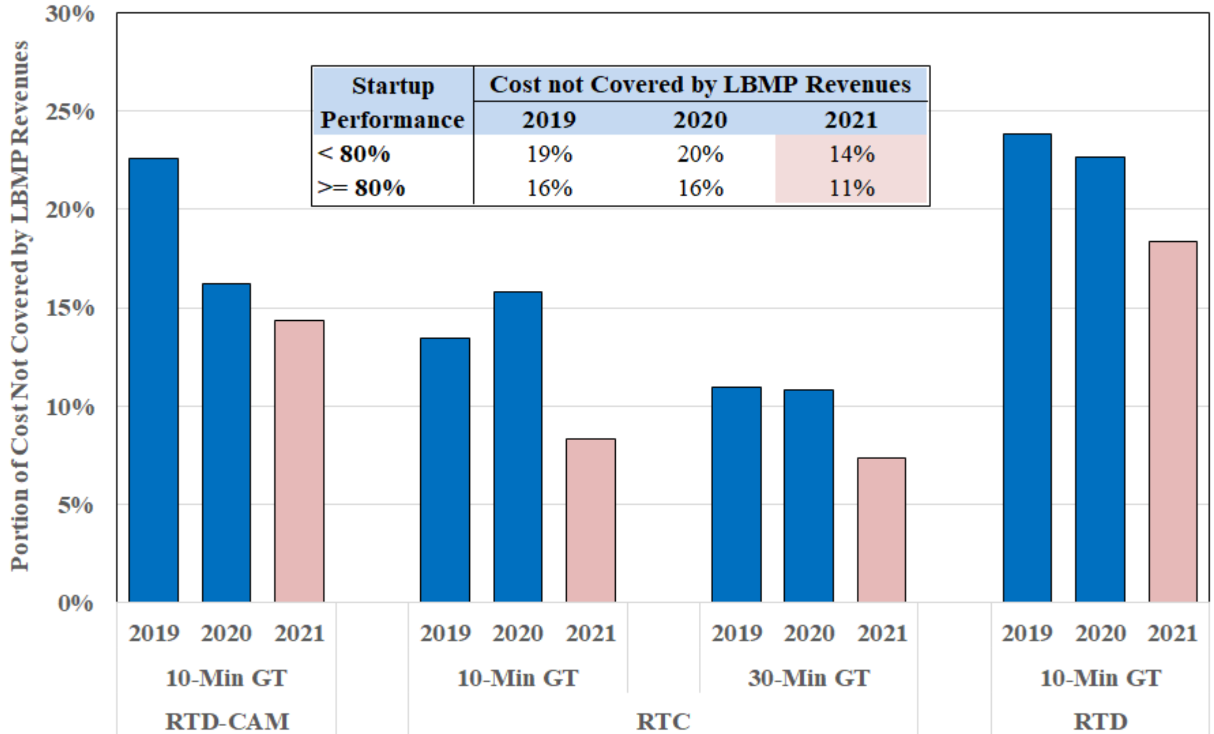
317 The Real-Time Dispatch – Corrective Action Mode (RTD-CAM) is version of RTD that NYISO operators can run on-demand to address abnormal or unexpected system conditions.

- GTs that are started efficiently to address a transient shortage (e.g. transmission constraint violation lasting less than one hour, or a reserve pickup by RTD-CAM) may lower LBMPs and appear uneconomic over the commitment period.

- The start-up and minimum generation costs were not incorporated in the LBMP-setting logic until 2021.

Figure A-82 evaluates starts separately for 10-minute and 30-minute gas turbines and whether they were started by RTC, RTD, or RTD-CAM. The inset table also compares their overall commitment efficiency on an annual basis for these years. Since the units that do not follow the instructions tend to operate in a later period that is likely uneconomic (which appears to be less efficient, but this is due to Participant behavior rather than commitment efficiency), the table also shows startup efficiency separately for two performance groups (i.e, 80+ percent or else). 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).[318]

Figure A-82: Efficiency of Gas Turbine Commitment
2019-2021



318 For example, for a 50 MW 10-minute GT, if its output is 40 MW at 10 minute after receiving a start-up instruction, then its response rate is 80 percent.

Table A-9 & Figure A-83 - Figure A-84: Combined-Cycle Unit Duct Burner Capacity and Availability 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-9 summarizes the amounts of duct-firing capability in the summer and winter capability periods by load zone.

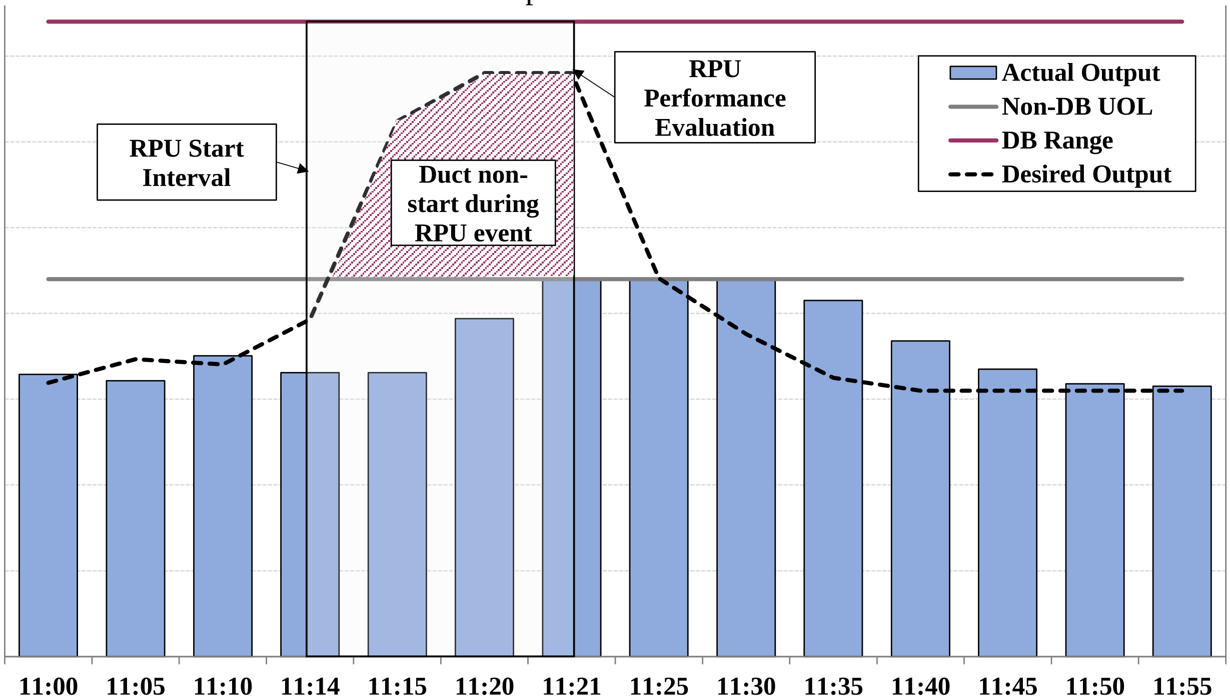
Table A-9: Combined-Cycle Unit Duct Burner Capacity in New York

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	190.5	236
Long Island	4	96	102
NYCA Total	**42**	**802.5**	**848**

Figure A-83 shows an example of a combined-cycle unit that could not follow dispatch instructions during a Reserve Pickup ("RPU") event due to its inability to fire the duct burner within 10-minutes. However, this duct burner capacity is considered capable of following 5-minute dispatch signals in the market scheduling and pricing software. This disconnect presents challenges in real-time operations when the duct-firing capacity becomes more valuable under tight system conditions like an RPU event.

Figure A-83: Duct Burner Real-Time Dispatch Issue
Example of a Failed RPU



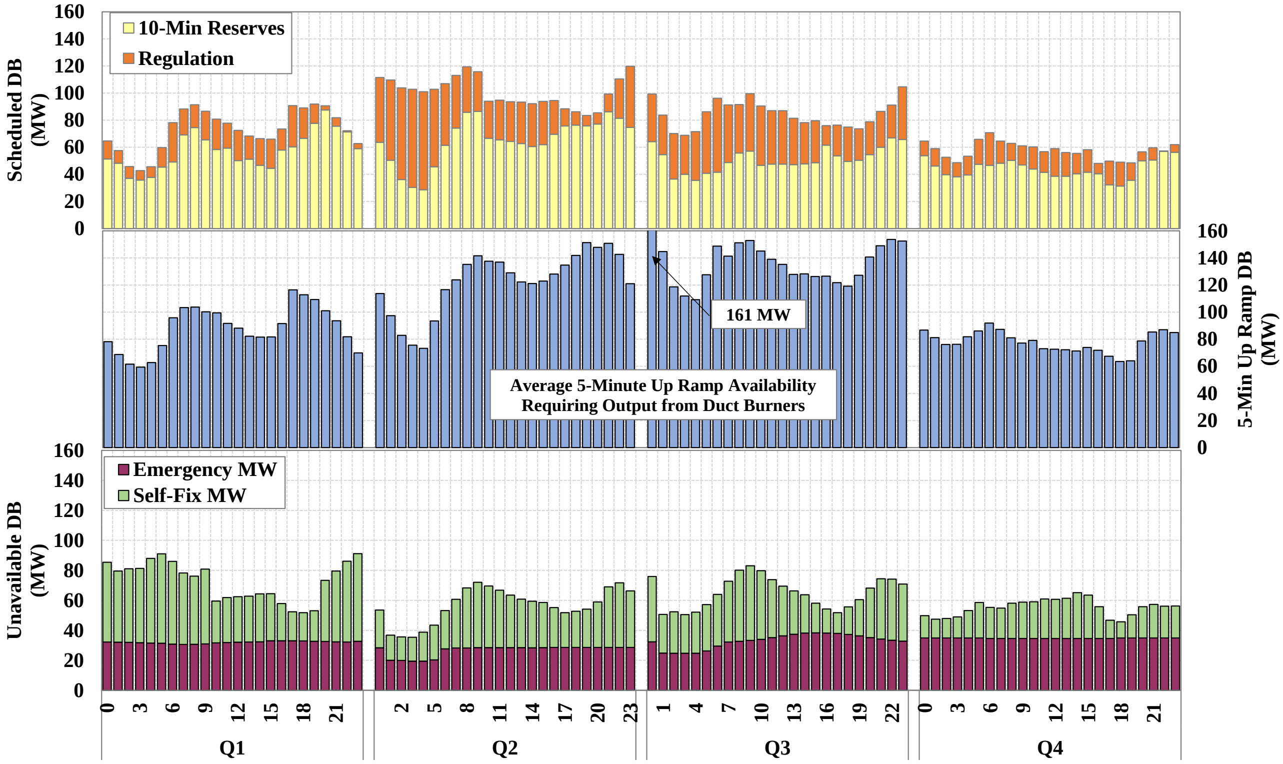
In the figure, the two lines show the levels where resource capacity shifts from baseload without duct burners (gray line) to the duct burner range (red line). Capacity values are not given for confidentiality purposes. The blue bars show the actual output produced by the resource in each RTD and RTD-CAM interval. The black dashed line shows the 5-minute instructions by the market model. The red-patterned area between the gray line and the instructed output line outlines the duct burner output that was not actually deliverable by the resource.

Figure A-84 examines duct burner availability in the real-time market for each quarter of 2021. The quantities in the charts are calculated for each 5-minute interval and then aggregated to the hourly level.

The top panel of the chart shows the average amount of MWs from duct burners scheduled in real-time to provide 10-minute spinning reserves and regulation services. The middle panel shows the amount of 5-minute up-ramping capability that is the in the duct-firing range. These capacities were offered as available but not physically capable of providing these services in the required timeframe.

The bottom portion shows the average amount of duct burner capacity that was unavailable in real-time because of: a) no offer in this range (labeled as ‘Emergency MW’); or b) non-dispatchable due to inflexible self-schedule level (labeled as ‘Self-Fix’ MW).

Figure A-84: Examining Duct Burner Availability in Real-Time
2021



B. Performance of Operating Reserve Providers

Wholesale markets should provide efficient incentives for resources to help the ISO maintain reliability by compensating resources consistent with the value they provide. This sub-section evaluates: a) the performance of GTs in responding to start-up instructions in the real-time market; and b) how the expected performance of operating reserve providers affects the cost of congestion management in New York City.

Figure A-85 - Figure A-87 & Table A-10: Average GT Performance after a Start-Up Instruction

Figure A-85 to Figure A-87 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) .[319] The figure reports the average performance in 2020 and 2021. 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).[320] Figure A-85 shows the performance evaluation for all GTs while Figure A-86 and

319 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.

320 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-87 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-87.

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-10 also tabulates this comparison for 2021 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 2021 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: "43 GTs exhibited a response rate of 80 to 90 percent during economic starts in 2021, 40 of them were audited 82 times in total with 11 failures".

Figure A-85: Average GT Performance by Type after a Start-Up Instruction
Economic Starts vs Audit, 2020-2021

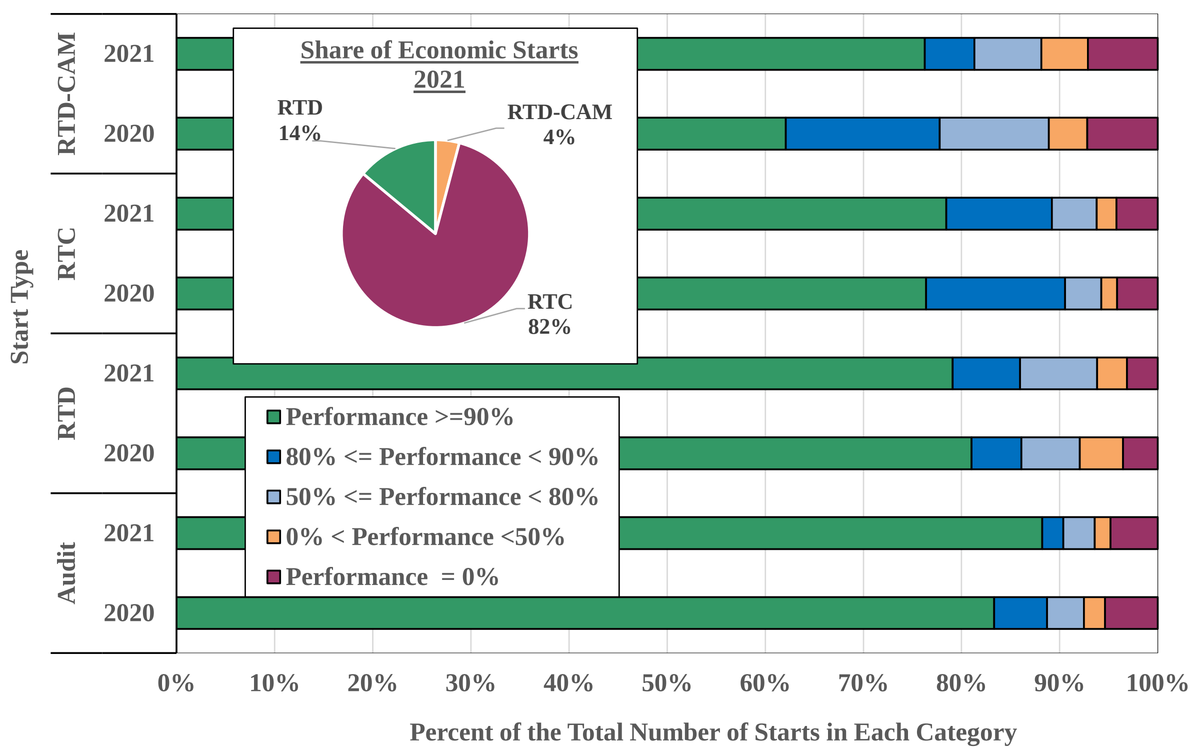


Figure A-86: Average GT Performance by Type after a Start-Up Instruction
Economic Starts vs Audit, for 10-Minute GTs, 2020-2021

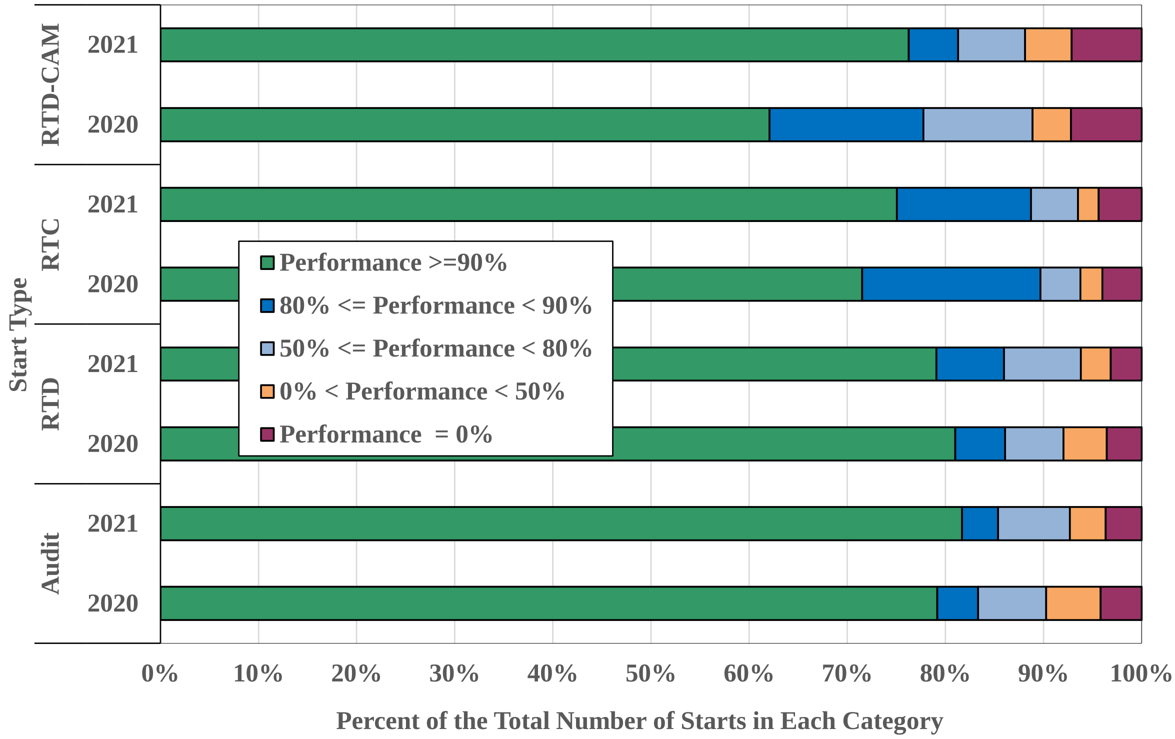


Figure A-87: Average GT Performance by Type after a Start-Up Instruction
Economic Starts vs Audit, for 30-Minute GTs, 2020-2021

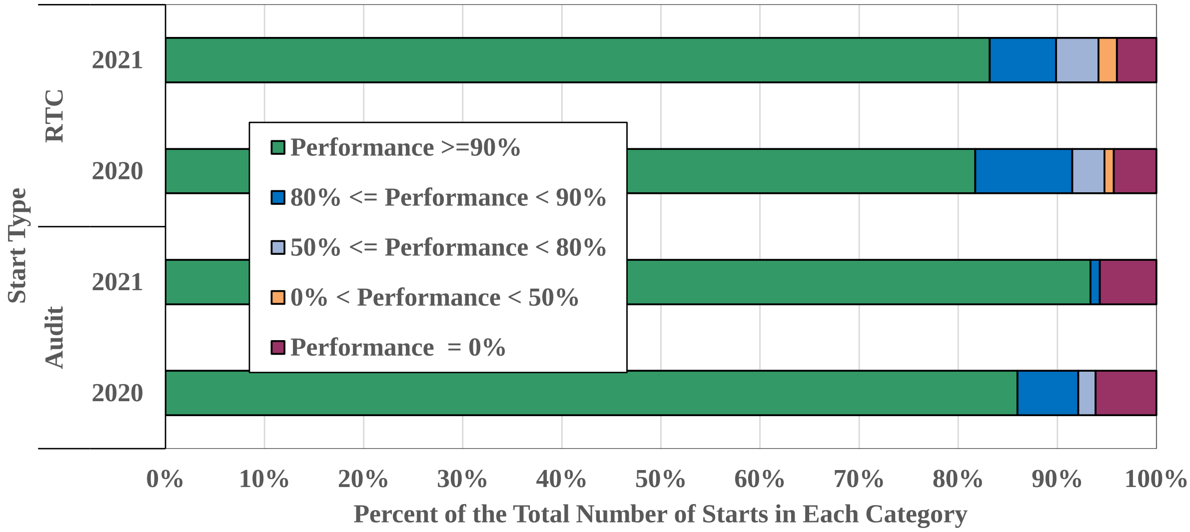


Table A-10: Economic GT Start Performance vs. Audit Results
2021

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]	17	16	11	2
0% - 10%	2	1	1	1
10% - 20%	0	0	0	0
20% - 30%	1	4	1	0
30% - 40%	0	0	0	0
40% - 50%	3	3	2	1
50% - 60%	3	8	3	0
60% - 70%	3	5	2	0
70% - 80%	3	5	3	2
80% - 90%	43	82	40	11
90% - 100%	70	132	63	9
TOTAL	**145**	**256**	**126**	**26**

Note: 1. Includes 5 units that were never started by RTD, RTC, or RTD-CAM (excluding self-schedules) in 2021 and 12 units that were omitted due to certain data issues.

Figure A-88: 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-88 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 2021. The blue bars represent the congestion values measured up to the seasonal LTE ratings of the facilities.[321] The red bars represent the congestion values measured for the additional transfer capability above LTE.[322] 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.

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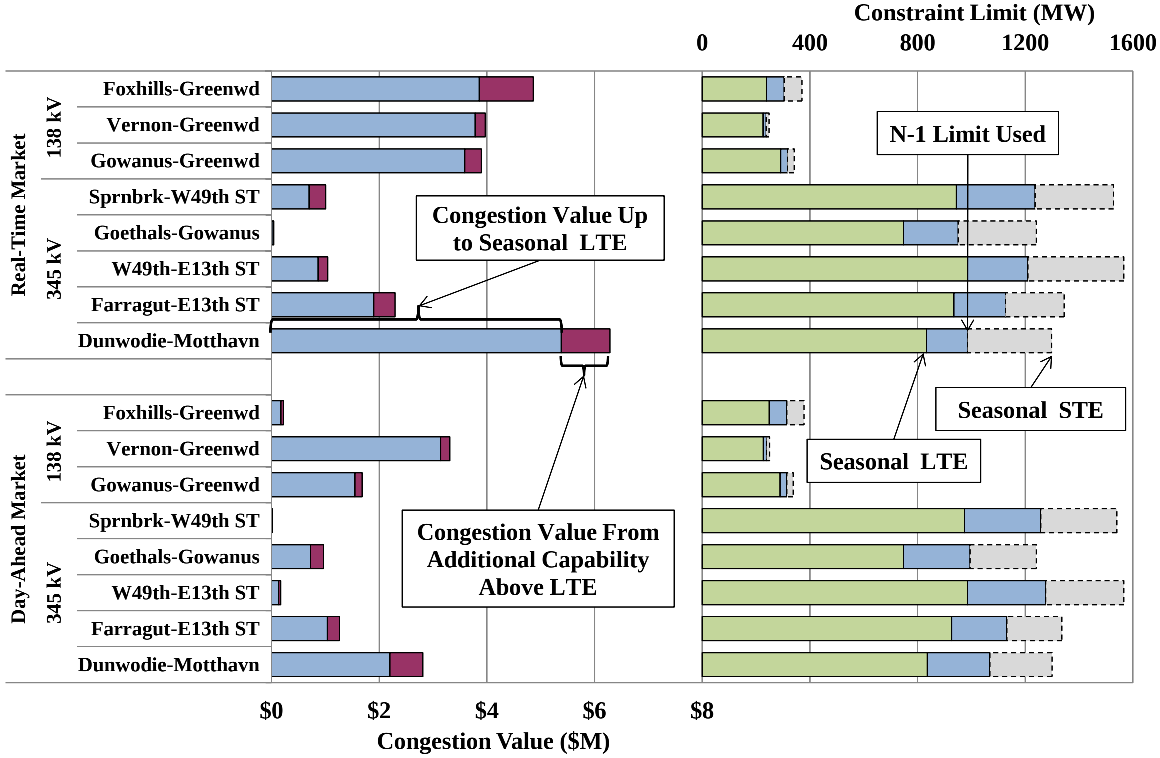
321 Congestion value up to seasonal LTE = constraint shadow cost × seasonal LTE rating summed across all market hours / intervals.

322 Congestion value for additional capability above LTE = constraint shadow cost × (modeled constraint limit - seasonal LTE rating) summed across all market hours / intervals.

Figure A-88: Use of Operating Reserves to Manage N-1 Constraints in New York City
Limits Used vs Seasonal LTE Ratings, 2021



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.[323] 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.[324]

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

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

324 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.

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.[325]

Figure A-89: 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 2021.

Figure A-89 evaluates operations of these NY-NJ PARs under M2M with PJM in 2021 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.

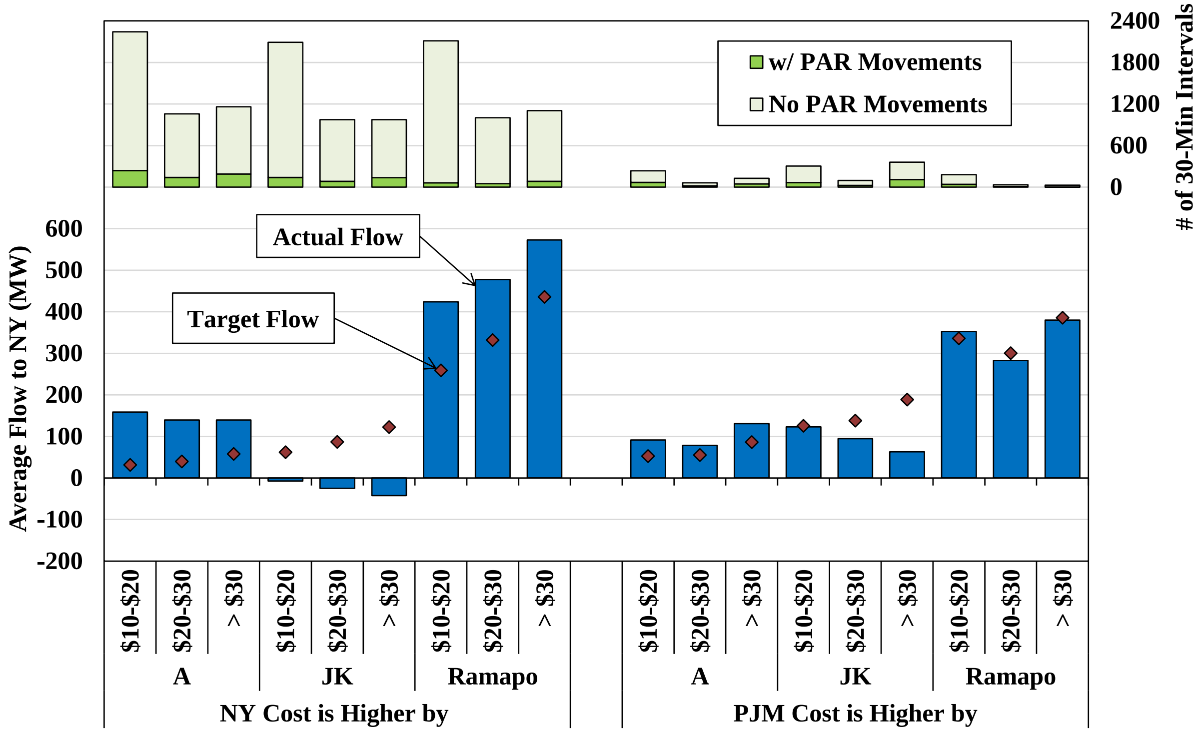
- When PJM costs on relevant M2M constraints exceed NY costs by: a) $10/MWh to $20/MWh; b) $20/MWh to $30/MWh; or c) more than $30/MWh;

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).

325 The list of pre-defined flowgates is posted here in the sub-group “Notices” under “General Information”.

Figure A-89: NY-NJ PAR Operation under M2M with PJM
2021



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.[326] 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.

326 This includes the Cross Sound Cable (an HVDC line), the Neptune Cable (an HVDC line), the HVDC line connecting NYCA to Quebec, the Dennison Scheduled Line (partly VFT-controlled), the 1385 Scheduled Line (PAR-controlled), and the Linden VFT Scheduled Line.

Table A-11 and Figure A-90: 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 2021.

Table A-11 evaluates the consistency of the direction of power flows on non-optimized PAR-controlled lines and LBMP differences across these lines during 2021. The evaluation is done for the following eleven PAR-controlled lines:

- 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-11 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.[327]

[327] 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

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.[328] For Ontario, the analysis assumes a day-ahead schedule of 0 MW since Ontario does not operate a day-ahead market. The vast majority of power is scheduled in the day-ahead market, while small balancing adjustments are typically made in the real-time market.

Table A-11: Efficiency of Scheduling on Non-Optimized PAR Controlled Lines
2021

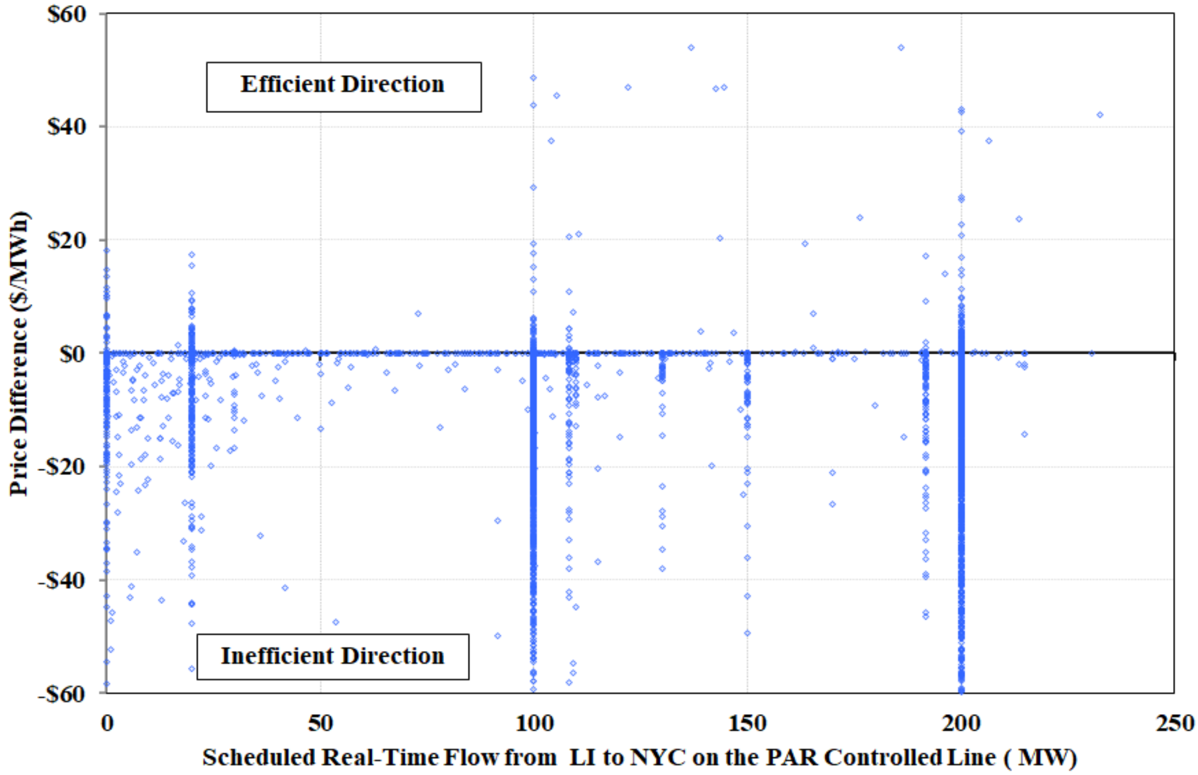
	Day-Ahead Market Schedule				Adjustment in Real-Time			
	Avg Flow (MW)	Avg NYCA Price minus Avg Outside Price ($/MWh)	Percent of Hours in Efficient Direction	Estimated Production Cost Savings (Million $)	Avg Flow (MW)	Avg NYCA Price minus Avg Outside Price ($/MWh)	Percent of Hours in Efficient Direction	Estimated Production Cost Savings (Million $)
Ontario to NYCA								
St. Lawerence					-19	$1.63	51%	$0.6
New England to NYCA								
Sand Bar	-49	-$21.18	97%	$10	0.1	-$19.89	56%	$0.4
PJM to NYCA								
Waldwick	85	$5.06	81%	$4	45	$4.14	54%	-$1.2
Ramapo	333	$6.23	89%	$17	110	$5.83	69%	$5.5
Goethals	39	$6.79	83%	$2	98	$6.59	63%	$1.5
Long Island to NYC								
Lake Success	107	-$10.38	16%	-$7	4	-$11.95	37%	$2.3
Valley Stream	72	-$10.60	2%	-$5	-1	-$11.55	42%	-$0.1

Figure A-90 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.

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.

328 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.

Figure A-90: Efficiency of Scheduling on PAR Controlled Lines
Lake Success-Jamaica Line – 2021



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 2021. The effects of transient transmission constraints tend to be localized, while transient spikes in the power-balance constraint affect prices throughout NYCA.

A spike in the shadow price of a particular transmission constraint is considered *"transient"* if it satisfies both of the following criteria:

- It exceeds $150 per MWh; and
- It increases by at least 100 percent from the previous interval.

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

- The price at the reference bus exceeds $100 per MWh; and
- It increases by at least 100 percent from the previous interval.

Although the price spikes meeting these criteria 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-12: Transient Real-Time Price Volatility

Table A-12 summarizes transient real-time price spikes by constraint (including transmission facilities and power-balance constraints) in 2021 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).[329,330] RTD and RTC assume the flow over these lines will remain fixed in future intervals,[331] but their flow is affected by changes in generation and load and changes in the settings of the fixed schedule PAR or other nearby PARs. Hence, RTD and RTC do not anticipate changes in flows across fixed schedule PARs in future intervals, which can lead to sudden congestion price spikes when RTD recognizes the need to redispatch internal resources in response to unforeseen changes in flows across a fixed schedule PAR.

- RTC Shutdown Peaking Resource – This includes gas turbines and other capacity that is brought offline by RTC based on economic criteria. When RTC shuts-down a significant amount of capacity in a single 5-minute interval, it can lead to a sudden price spike if dispatchable internal generation is ramp-limited.

- Loop Flows & Other Non-Market Scheduled – These include flows that are not accounted for in the pricing logic of the NYISO's real-time market. These result when other system operators schedule resources and external transactions to satisfy their internal load, causing loop flow across the NYISO system. These also result from differences between the shift factors assumed by the NYISO for pricing purposes and the actual flows that result from adjustments in generation, load, interchange, and PAR controls.

- Self-Scheduled Generator – This includes online generators that are moving in accordance with a self-schedule, resources shut-down in accordance with a self-schedule, and resources that are shut down because they did not submit a RT offer. In some cases, large inconsistencies can arise between the ramp constraints in the physical and pricing passes of RTD for such units.

- Load – This includes the effects of changes in load.

- Generator Trip/Derate/Dragging – Includes adjustments in output when a generator trips, is derated, or is not following its previous base point.

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329 These lines are discussed further in Subsection D.

330 M2M coordination is discussed further in Subsection C.

331 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-12, 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-12: Drivers of Transient Real-Time Price Volatility
2021

	Power Balance		West Zone Lines		Central East		Upstate to Long Island		Intra-Long Island Constraints		Capital to Hudson Valley		New York City Load Pockets		North to Central	
Average Transfer Limit	**n/a**		**259**		**1071**		**472**		**262**		**1059**		**263**		**236**	
Number of Price Spikes	**280**		**2395**		**697**		**440**		**1398**		**188**		**680**		**506**	
Average Constraint Shadow Price	**$265**		**$439**		**$370**		**$368**		**$588**		**$856**		**$456**		**$529**	
Source of Increased Constraint Cost:	**(MW)**	**(%)**	**(MW)**	**(%)**	**(MW)**	**(%)**	**(MW)**	**(%)**	**(MW)**	**(%)**	**(MW)**	**(%)**	**(MW)**	**(%)**	**(MW)**	**(%)**
Scheduled By RTC	**155**	**63%**	**0**	**0%**	**36**	**46%**	**41**	**52%**	**6**	**75%**	**17**	**25%**	**4**	**29%**	**2**	**25%**
External Interchange	71	29%	0	0%	15	19%	7	9%	1	13%	12	18%	1	7%	1	13%
RTC Shutdown Resource	63	25%	0	0%	15	19%	27	34%	2	25%	3	4%	3	21%	0	0%
Self Scheduled Shutdown/Dispatch	21	8%	0	0%	6	8%	7	9%	3	38%	2	3%	0	0%	1	13%
Flow Change from Non-Modeled Factors	**4**	**2%**	**3**	**100%**	**31**	**40%**	**25**	**32%**	**1**	**13%**	**47**	**70%**	**9**	**64%**	**2**	**25%**
Loop Flows & Other Non-Market	2	1%	2	67%	11	14%	18	23%	1	13%	38	57%	7	50%	2	25%
Fixed Schedule PARs	0	0%	1	33%	18	23%	5	6%	0	0%	9	13%	1	7%	0	0%
Redispatch for Other Constraint (OOM)	2	1%	0	0%	2	3%	2	3%	0	0%	0	0%	1	7%	0	0%
Other Factors	**89**	**36%**	**0**	**0%**	**11**	**14%**	**13**	**16%**	**1**	**13%**	**3**	**4%**	**1**	**7%**	**4**	**50%**
Load	53	21%	0	0%	8	10%	8	10%	1	13%	3	4%	1	7%	3	38%
Generator Trip/Derate/Dragging	16	6%	0	0%	2	3%	5	6%	0	0%	0	0%	0	0%	0	0%
Wind	20	8%	0	0%	1	1%	0	0%	0	0%	0	0%	0	0%	1	13%
Total	**248**		**3**		**78**		**79**		**8**		**67**		**14**		**8**	
Redispatch for Other Constraint (RTD)	**83**		**0**		**9**		**2**		**1**		**2**		**7**		**4**	

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 an uniform Regulation Movement Multiplier of 8 per MW of capability, [332] but they are deployed based on individual ramping capability and are compensated according to actual movement. This inconsistency between assumed costs and actual costs 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-91 & Figure A-92: Regulation Movement-to-Capacity Ratio

Figure A-91 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 8 that is used for all resources when formulating the composite regulation offer.

Figure A-91: Distribution of Actual Regulation Movement-to-Capacity Ratio
From a Sample Day

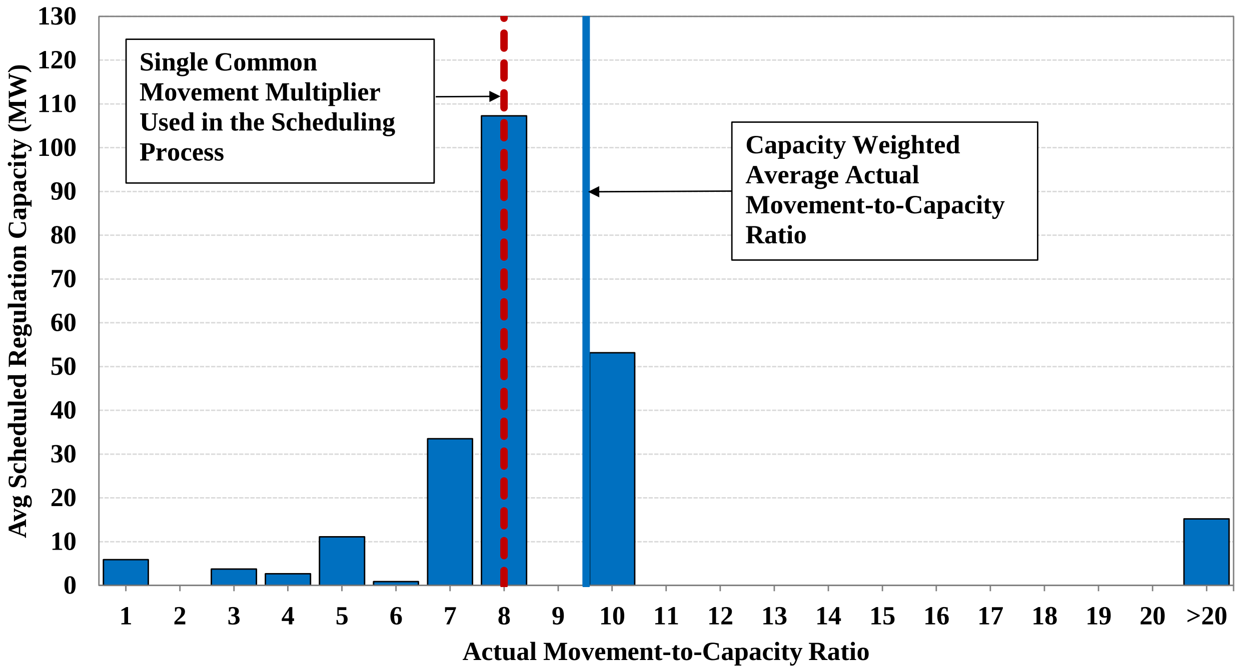


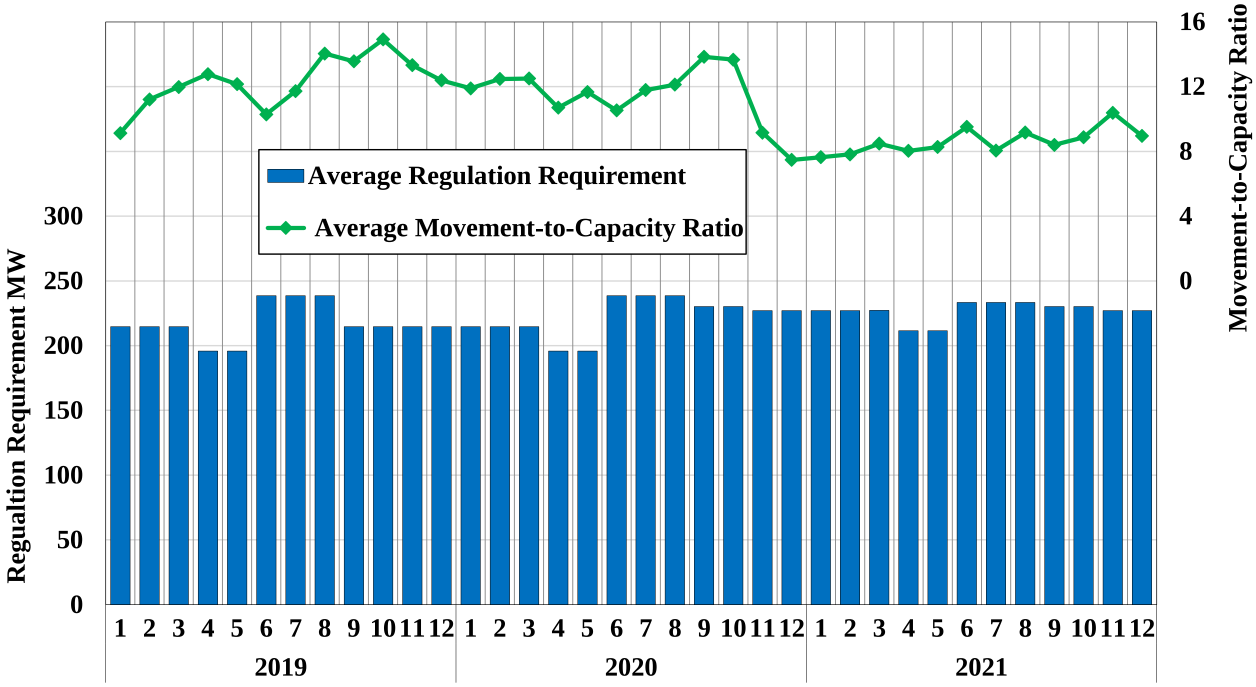
Figure A-92 tracks the variation of regulation movement-to-capacity ratio in recent years, summarizing the following quantities by month:

332 The uniform Regulation Movement Multiplier was changed from 13 to 8 on August 31, 2021.

- 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-92: Regulation Requirement and Movement-to-Capacity Ratio
By Month, 2019-2021



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 2021:

- Shortages of operating reserves and regulation (evaluated in this Subsection); and
- Transmission shortages (evaluated in Subsection H).

Figure A-93: Real-Time Prices During Physical Ancillary Services Shortages

The NYISO's approach to efficient pricing during operating reserves and regulation shortages is to use ancillary services demand curves. The real-time dispatch model ("RTD") co-optimizes the procurement of energy and ancillary services, efficiently allocating resources to provide energy and ancillary services every five minutes. When RTD cannot satisfy both the energy demand and ancillary services requirements with the available resources, the demand curves for ancillary services rationalize the pricing of energy and ancillary services during shortage periods by causing prices to reflect the value of foregone ancillary services. The demand curves also set limits on the costs that can be incurred to maintain operating reserves and regulation.

Figure A-93 summarizes physical ancillary services shortages and their effects on real-time prices in 2020 and 2021 for the following eight categories: [333]

- 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 $40/MW if the shortage is less than 200 MW, $100/MW if the shortage is between 200 and 325 MW, $175/MW if the shortage is between 325 and 380 MW, $225/MW if the shortage is between 380 and 435 MW, $300/MW if the shortage is between 435 and 490 MW, $375/MW if the shortage is between 490 and 545 MW, $500/MW if the shortage is between 545 and 600 MW, $625/MW if the shortage is between 600 and 655 MW,and $750/MWh if the shortage is more than 655 MW. [334]
- 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/MW.
- 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/MW.
- 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/MW.

333 See *NYISO Ancillary Services Manual* for more details.

334 This new multi-step demand curve was effective on July 13, 2021.

- 30-minute SENY – The ISO is required to hold at least 1300 MW of 30-minute operating reserves in Southeast New York for all hours and has a demand curve value of $500/MW. Additional 30-minute operating reserves are required for a subset of hours and has a demand curve value of $40/MW in the incremental range.

- 10-minute NYC – 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/MW.

- 30-minute NYC – The ISO is required to hold 1000 MW of 30-minute operating reserves in New York City and has a demand curve value of $25/MW.

- 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/MW if the shortage is less than 25 MW, $525/MW if the shortage is between 25 and 80 MW, and $775/MW if the shortage is more than 80 MW.

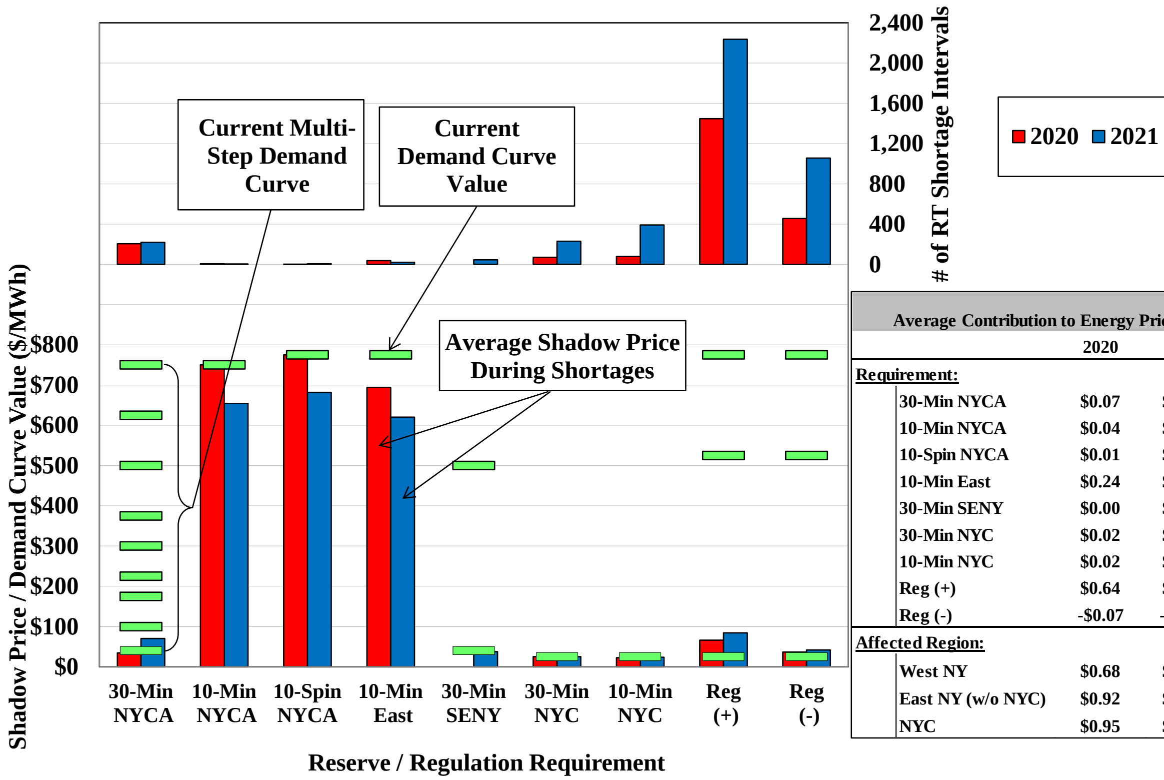
The top portion of the figure shows the frequency of physical shortages. The bottom portion shows the average shadow price during physical shortage intervals and the current demand curve level of the requirement. The table shows the average shadow prices during physical shortages multiplied by the frequency 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-93: Real-Time Prices During Ancillary Services Shortages
2020 – 2021



Average Contribution to Energy Price

	2020	2021
Requirement:		
30-Min NYCA	$0.07	$0.15
10-Min NYCA	$0.04	$0.02
10-Spin NYCA	$0.01	$0.03
10-Min East	$0.24	$0.12
30-Min SENY	$0.00	$0.02
30-Min NYC	$0.02	$0.05
10-Min NYC	$0.02	$0.09
Reg (+)	$0.64	$1.37
Reg (-)	-$0.07	-$0.22
Affected Region:		
West NY	$0.68	$1.35
East NY (w/o NYC)	$0.92	$1.49
NYC	$0.95	$1.63

Figure A-94 & Table A-13: Reserves Shortages in New York City

The NYISO currently models two reserves requirements in NYC: [335]

- 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-13 shows the real-time market performance during reserves shortages in New York City for each month in 2021 (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.
- 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.

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335 The NYISO started to model these two requirements on June 26, 2019.

- # 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-13: Real-Time Reserve Shortages in New York City
2021

Month	RT Reserve Shortages in NYC in 2021					
	w/ TSA			w/o TSA		
	# Intervals	Avg. Shortage MW	#Intervals w/ toNYC Congestion	# Intervals	Avg. Shortage MW	#Intervals w/ toNYC Congestion
Feb				1	16	0
May	38	364	0	16	103	0
Jun	77	419	0	231	158	22
Jul				24	65	4
Aug				76	45	1
Sep				92	90	14
Oct				19	101	0
Nov				64	87	0
Dec				17	35	0
Total	**115**	**401**	**0**	**540**	**110**	**41**

Figure A-94 illustrates a sample real-time shortage event that coincided with a TSA event on May 26, 2021. The TSA event occurred from 17:00 to 21:00, while New York City was short of reserves (either 10-minute or 30-minute or both) primarily from 17:00 to 20:00. For each interval from the beginning of hour 16 to the end of hour 21, the figure shows:

- The amount of reserve shortages (red bar); and
- Net imports from upstate areas (blue bar).[336]

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. 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.

336 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).

Figure A-94: Real-Time Reserve Shortages in New York City
Sample Event on May 26, 2021

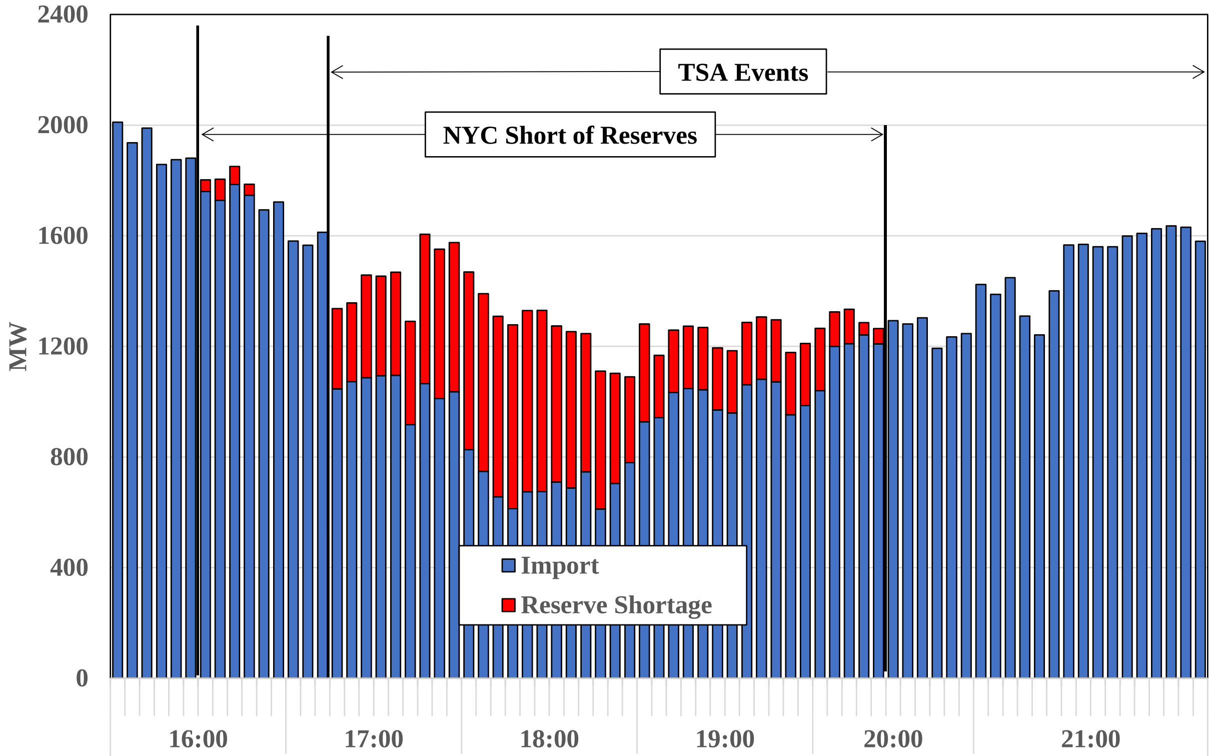


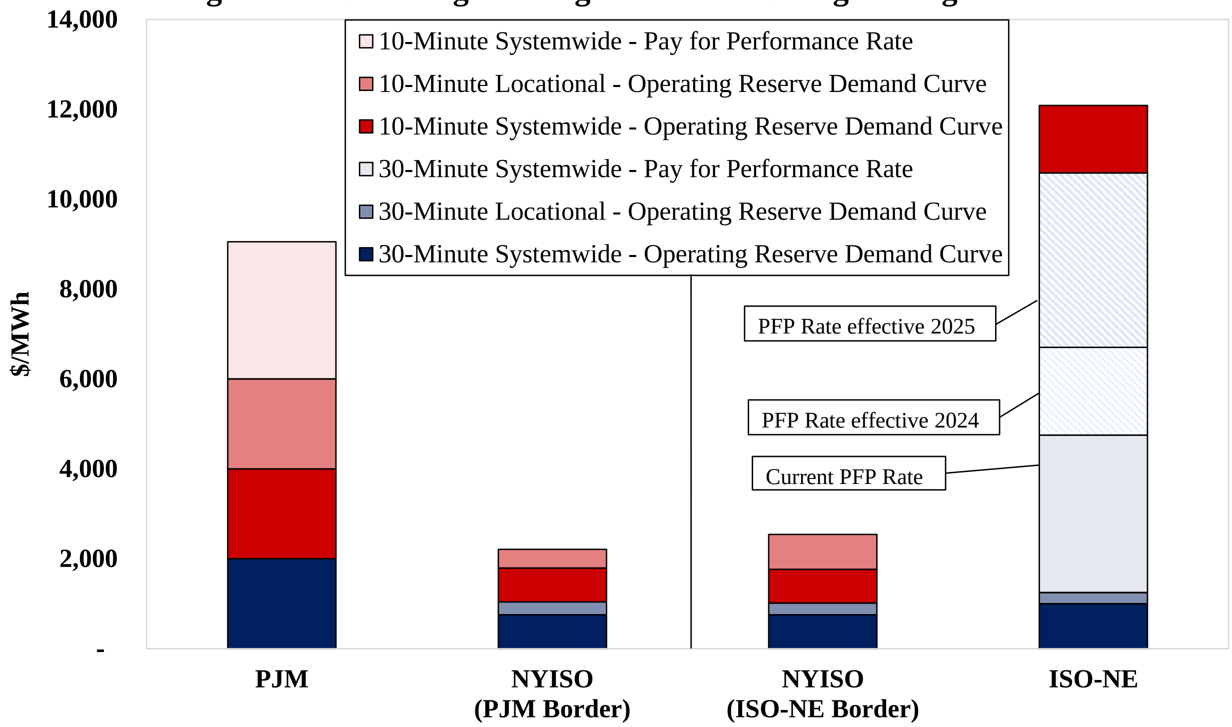
Figure A-95: Comparison of Shortage Pricing in NYISO and Neighboring Markets

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 and $9,337/MWh in 2025. 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-95 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 approved by FERC in 2021, which increased some shadow prices. 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.[337]

Figure A-95: Shortage Pricing in NYISO vs. Neighboring Markets



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.

337 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.

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, [338] 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").[339]

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.[340] In such cases, the marginal cost of resources actually dispatched to relieve the constraint is lower than the shadow price set by the offline gas turbine (which is not actually started). The Commission has recognized that it is not efficient for such units to set the clearing price because such a unit: (a) does not reflect the marginal cost of supply that is available to relieve the constraint in that time interval, and (b) does not reflect the marginal value of the constraint that may be violated when it does not generate as assumed in RTD. [341] This category of shortage is evaluated in this section as well.

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[338] 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.

[339] These changes are discussed in detail in Commission Docket ER17-1453-000.

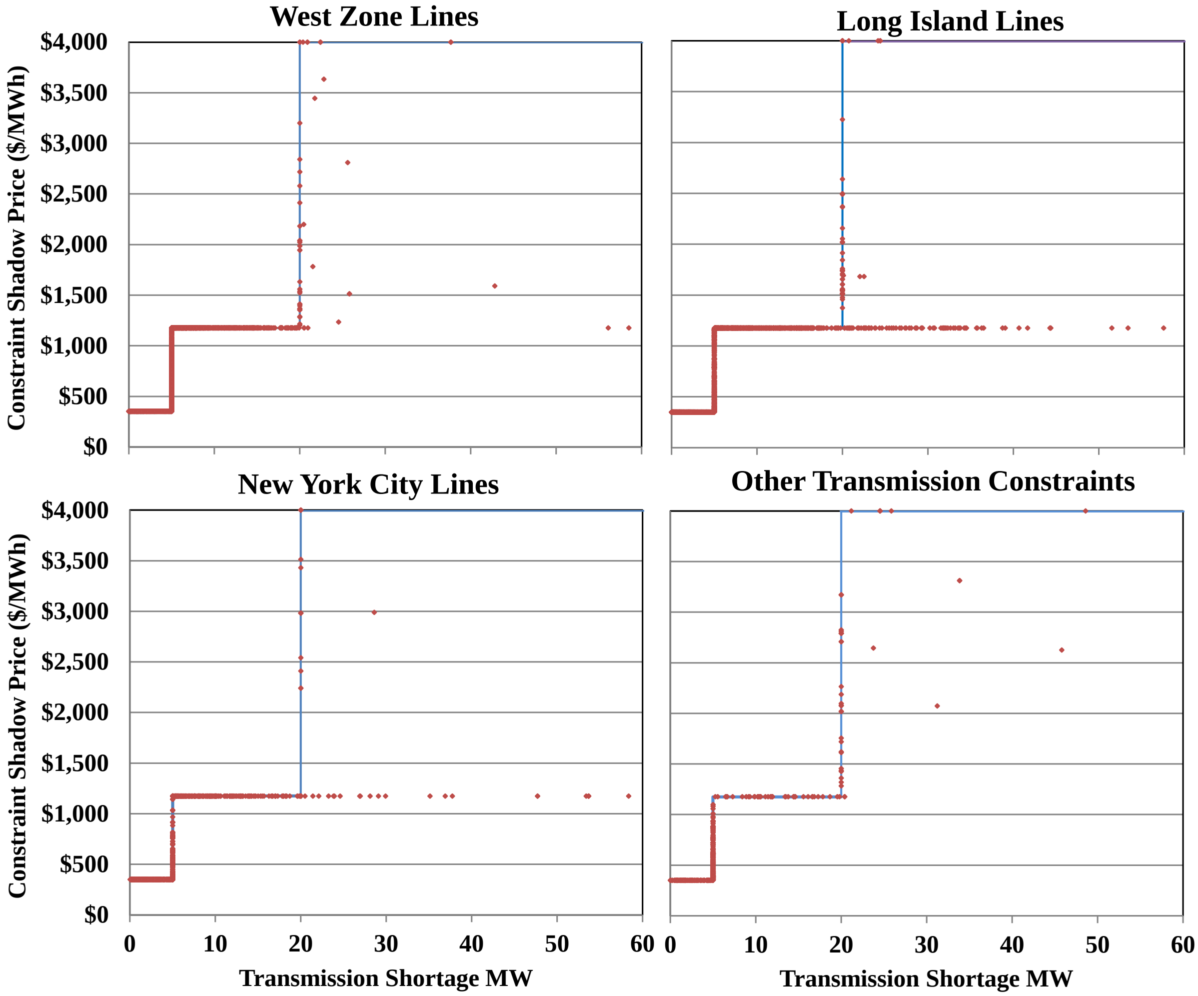
[340] Offline quick-start gas turbine is usually the most expensive available capacity due to their commitment costs, so offline gas turbines are usually not counted towards resolving the constraint unless all available online generation has already been scheduled. If a gas turbine is scheduled by RTD 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.

[341] 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.

Figure A-96, Table A-14 & Figure A-97: Real-Time Congestion Management with GTDC

Figure A-96 examines the use of the GTDC during transmission shortages in the real-time market by constraint group in 2021.

Figure A-96: Real-Time Transmission Shortages with the GTDC
By Transmission Group, 2021



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)[342] showing on the x-axis and the constraint shadow price on the y-axis.

Table A-14 evaluates the congestion-relief effect from offline GTs and the effect of CRM on different transmission constraints in 2021. The table summarizes the following quantities for the transmission constraints grouped by facility voltage class and by location:

342 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.

- 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.

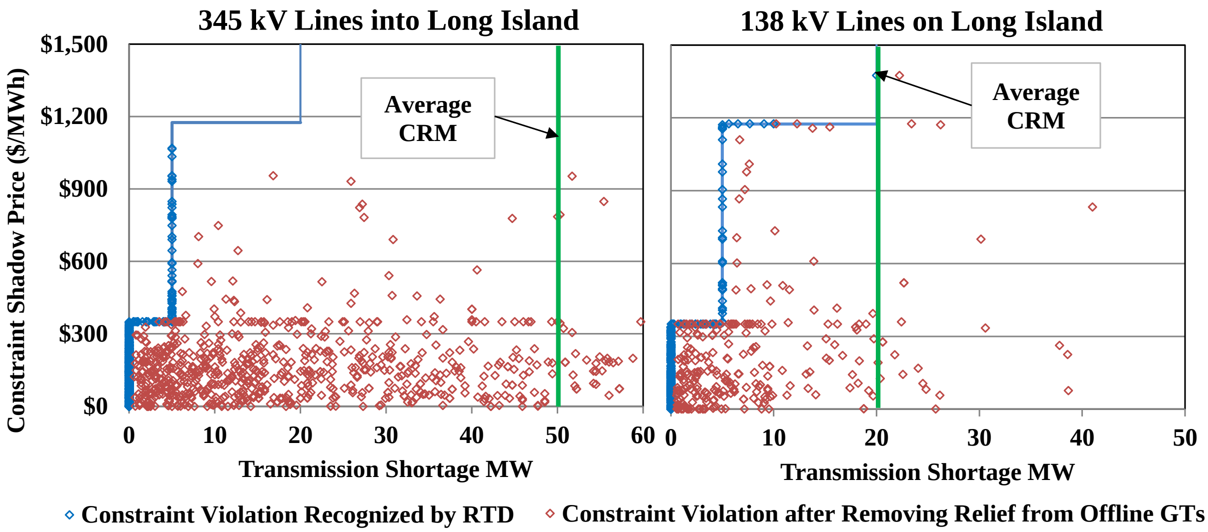
The table shows that offline GTs were used much more frequently to manage congestion on the transmission facilities on Long Island than in other regions in 2021. Therefore, Figure A-97 focuses on examining the price effects of offline GTs on transmission constraints on Long Island, grouped as: (a) the 345 kV transmission circuits from upstate to Long Island; and (b) the 138 kV transmission constraints within Long Island.

Table A-14: Constraint Limit and CRM in New York
During Real-Time Transmission Shortage Intervals, 2021

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			
69 kV	**Long Island**	2402	2426	4	4	116	10	9%
115 kV	**West**	4425	4425	4	4	205	10	5%
	North	1059	1059	4	4	142	10	7%
	All Others	321	327	15	15	249	10	4%
138 kV	**New York City**	1041	1119	5	6	235	20	9%
	Long Island	715	987	7	10	302	22	7%
	All Others	1219	1250	8	9	288	20	7%
230 kV	**West**	235	235	9	9	648	42	6%
	North	282	284	14	14	363	20	6%
	All Others	731	776	5	5	505	20	4%
345 kV	**New York City**	63	183	7	19	910	20	2%
	North	1	1	20	20	2079	50	2%
	Long Island	142	812	1	22	718	50	7%
	All Others	182	478	12	21	1426	21	1%

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-97: Transmission Constraint Shadow Prices and Violations
With and Without Relief from Offline GTs, 2021



I. Market Operations and Prices on High Load Days

Despite several heat waves in the summer of 2021, load exceeded 30 GW on just one day. The NYISO activated reliability demand response resources (i.e., EDRP/SCRs) for Long Island on six days. In addition, NYISO SREed resources for statewide capacity needs and local TOs activated various amounts of utility demand response resources on several days.[343] This subsection evaluates prices under these market conditions.

Figure A-98 & Figure A-99: Market Operations and Prices on High Load Days

Figure A-98 and Figure A-99 summarize market outcomes on select high load days when SRE commitments were made by the NYISO to maintain adequate reserves and/or DR was deployed by NYISO and/or TOs. Both figures report the following quantities in each interval of afternoon peak hours (HB 12 - HB 21) 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;

343 See presentation "NYISO Summer 2021 Hot Weather Operations" by Wes Yeomans at 9/29 MC meeting for more details.

   - 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, adjusted for SCR/EDRP calls, which is 2620 MW plus estimated SCR/EDRP deployment. The dashed black lines show the quantity equal to the amount of deployed utility DR plus the SCR/EDRP-adjusted 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.

Figure A-98: SRE Commitments and Utility DR Deployment on High Load Days
2021

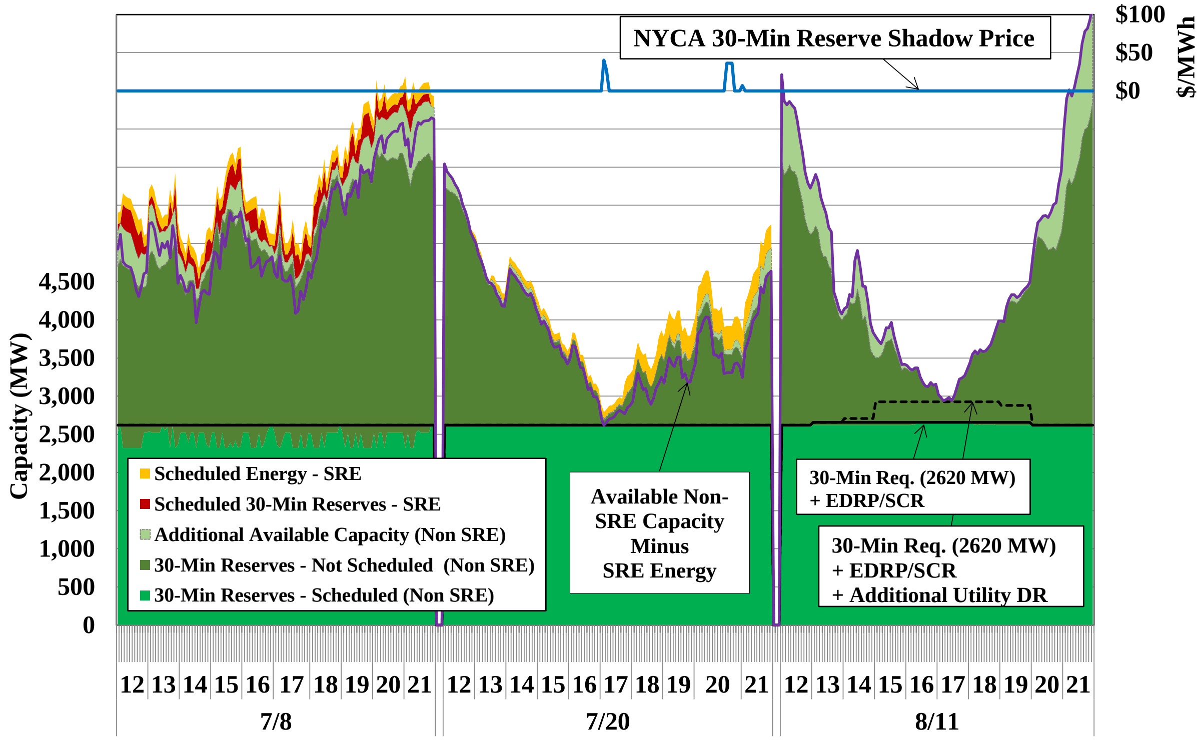
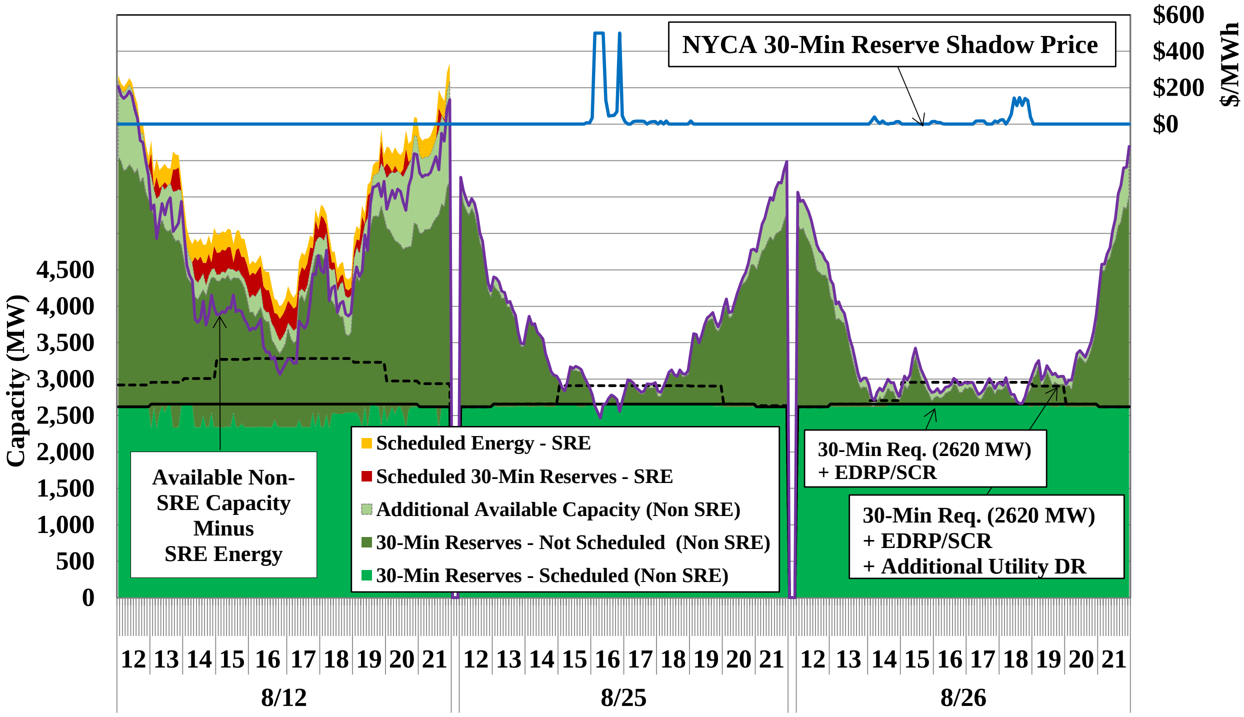


Figure A-99: SRE Commitments and Utility DR Deployment on High Load Days
2021



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-100: 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.

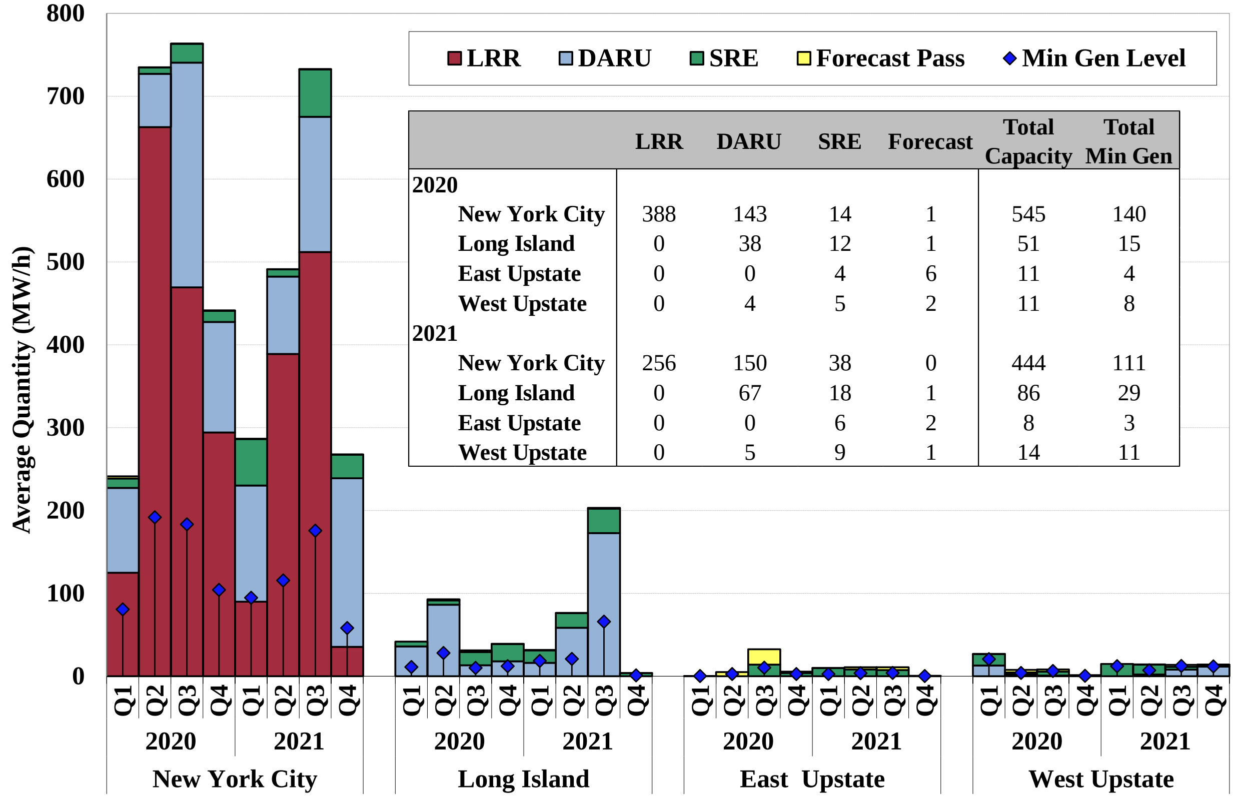
Generators that are committed for reliability are generally not economic at prevailing market prices, but they affect the market by: (a) reducing prices from levels that would otherwise result from a purely economic dispatch; and (b) increasing non-local reliability uplift since a portion of the uplift 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-100 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 2020 and 2021. 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 2020 and 2021 on an annual basis.

Figure A-100: Supplemental Commitment for Reliability in New York
By Category and Region, 2020 – 2021



	LRR	DARU	SRE	Forecast	Total Capacity	Total Min Gen
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
2021						
New York City	256	150	38	0	444	111
Long Island	0	67	18	1	86	29
East Upstate	0	0	6	2	8	3
West Upstate	0	5	9	1	14	11

Figure A-101- Figure A-102: Forecast-Pass Commitment in New York

In the day-ahead market, when the Bid Load Pass does not commit enough physical resources to meet forecast load and reserves requirements, the subsequent Forecast Pass will commit additional physical resources accordingly (indicated by the yellow bars in Figure A-100). However, this need is not currently priced in the market software, leading units committed for this purpose to often recoup their costs through BPCG uplift. Although the amount of FCT-committed capacity was modest on most days, it would still be beneficial to reflect the underlying needs through market signals.

Figure A-101 examines Forecast Pass commitments in 2020 and 2021. The x-axis shows all days when Forecast Pass commitments occurred during the two-year period. The solid blue bar shows, for each day, the total MWh committed by the Forecast Pass, including capacity from slow-start units and non-blocked quick-start units. The empty bar shows available offline capacity from non-blocked quick-start units during the hours when FCT commitments occurred. This capacity is currently not treated the same way as blocked quick-start units in the FCT pass to satisfy load and reserve requirements. If these quick-start units were recognized as quick-start by the software, most of the FCT commitments would not have been needed.

The inset table summarizes for 2020 and 2021:

- Total number of days when FCT commitments occurred;

- Total MWh committed in the FCT pass;
- Total available offline capacity from non-blocked quick-start units during FCT commitment hours; and
- Resulting total BPCG uplift.

Figure A-102 compares the FCT commitment with forecast physical energy needs in the day-ahead market in 2021, 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 includes capacity from internal slow-start resources and non-blocked quick-start units in the hours where it is not online in the economic pass but is online in the forecast pass.

Figure A-101: Forecast-Pass Commitment
2020-2021

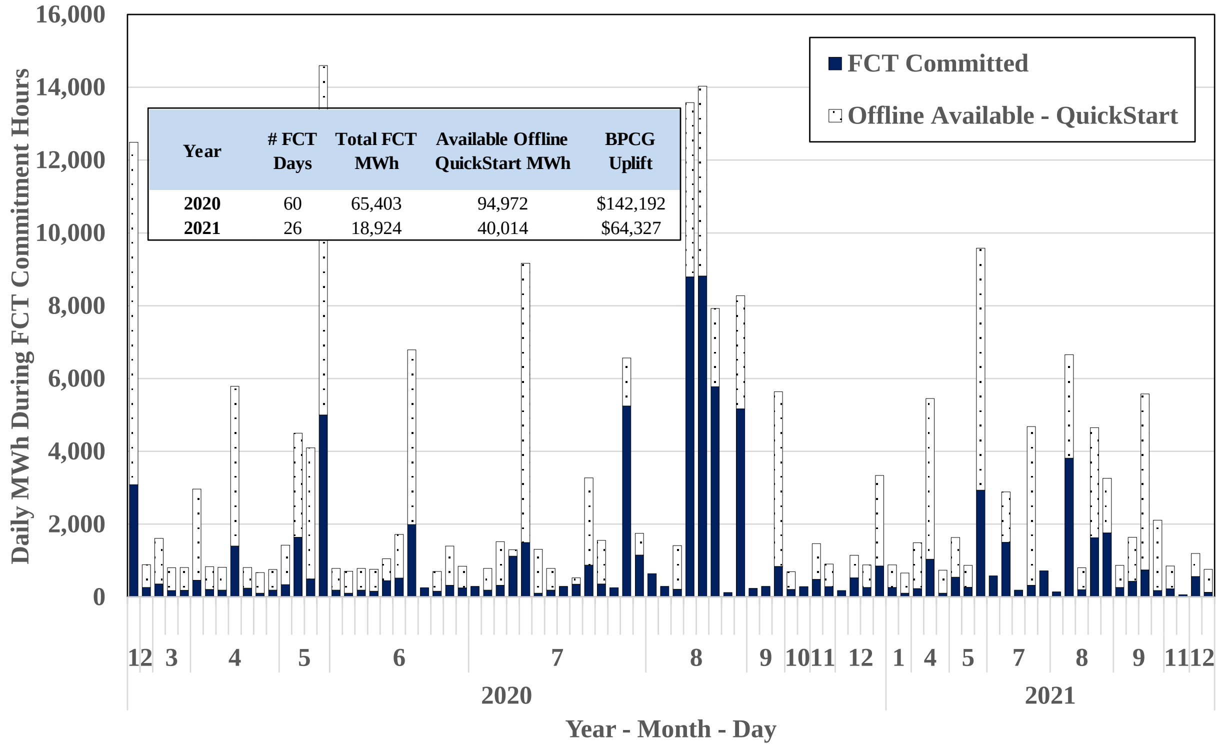


Figure A-102: FCT Commitment and DAM Forecast Physical Energy Needs
By Day, 2021

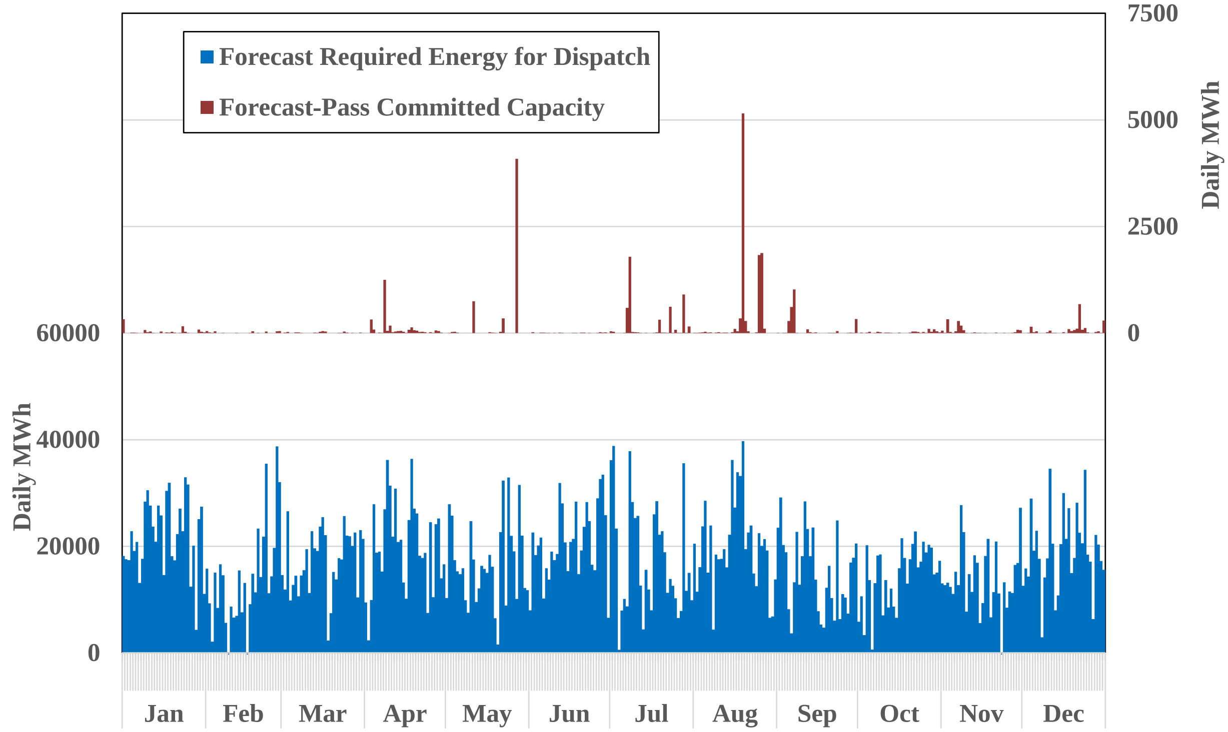


Figure A-103: Supplemental Commitment for Reliability in New York City

Most supplemental commitment for reliability occurred in New York City. Figure A-103 summarizes an analysis that identifies the causes for the reliability commitments in New York City. Specifically, Figure A-103 shows the minimum generation committed for reliability by reliability reason and by location in New York City during 2020 and 2021.

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: [344]

- N-1-1-0 – 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.

344 A unit is considered to be committed for a LRR constraint if the constraint would be violated without the unit's capacity.

- NOx – If needed for the NOx bubble requirement. [345] 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.[346]

In Figure A-103, 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.

345 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.

346 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-103: Supplemental Commitment for Reliability in New York City
By Category and Region, 2020 – 2021

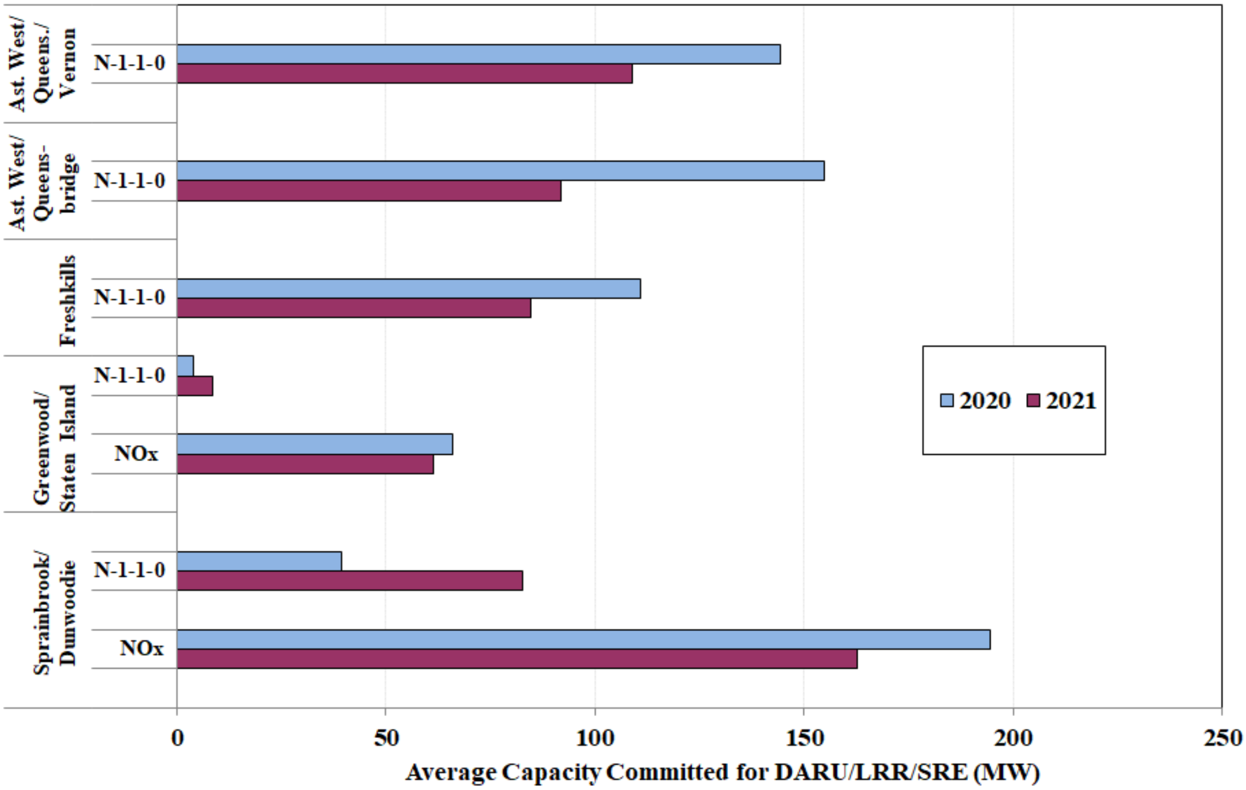


Figure A-104: Excess LRR Commitment in New York City

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-1-1-0 criteria could be satisfied by other resources. This suggests that such commitments are not necessary on some days in the Ozone season. Figure A-104 shows our evaluation of the necessity during the Ozone season of 2021.

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-1-1-0 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-104: Excess NOx-Rule LRR Commitment in New York City
Ozone Season, 2021

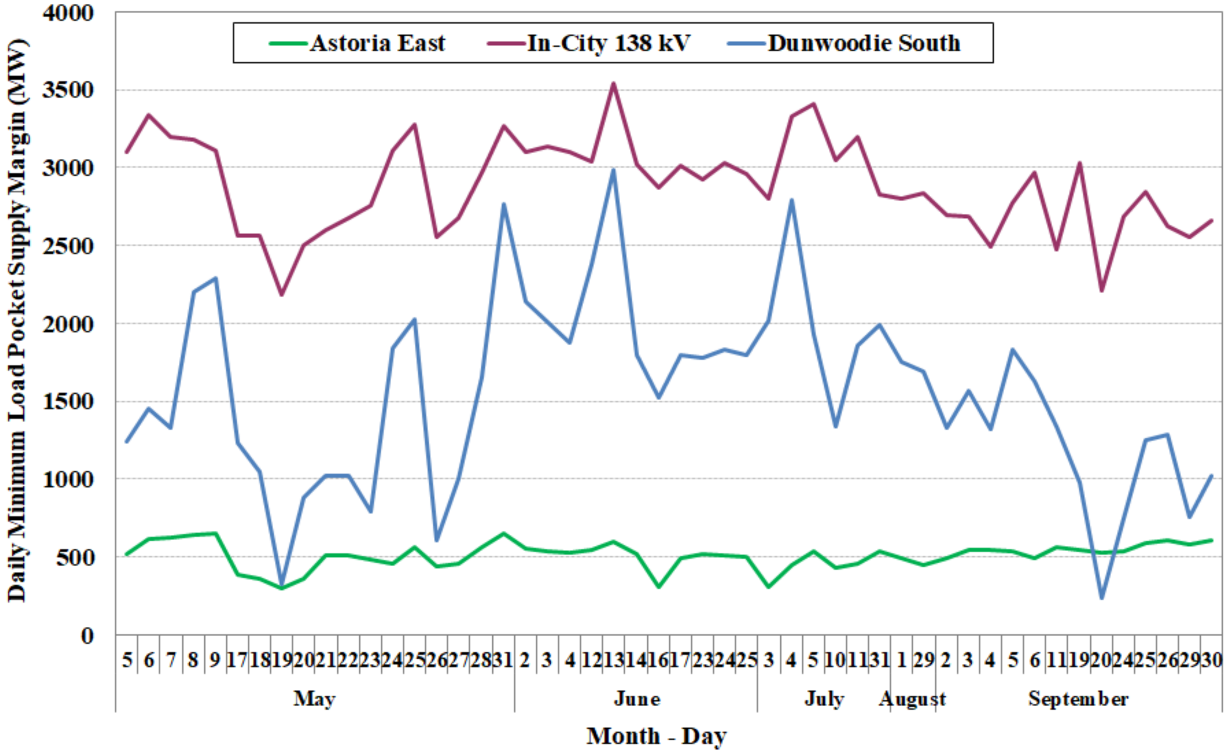


Table A-15: Day-ahead Reserve Price Estimates for Selected NYC Load Pockets

Reliability commitments frequently occur for local load pocket reliability (i.e., N-1-1-0 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-1-1-0 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-1-1-0 requirements in New York City, we estimated the average clearing prices that would have occurred in 2021 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-15 summarizes the results of this evaluation based on 2021 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-15: Day-ahead Reserve Price Estimates for Selected NYC Load Pockets
2021

Area	Average Marginal Commitment Cost ($/MWh)
NYC 345 kV System	$2.34
Selected 138 kV Load Pockets:	
Astoria West/Queensbridge	$3.64
Vernon	$3.20
Freshkills	$3.35

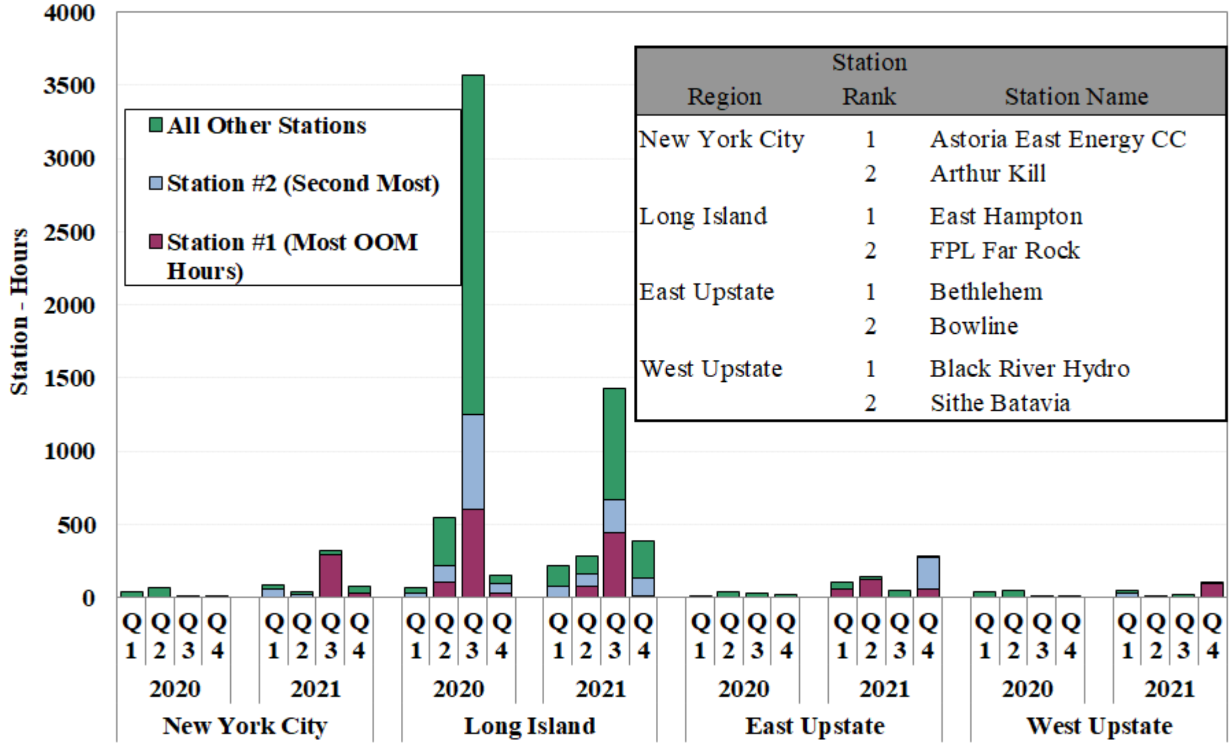
Figure A-105: Frequency of Out-of-Merit Dispatch

Figure A-105 summarizes the frequency (i.e., the total station-hours) of OOM actions on a quarterly basis in 2020 and 2021 for the following four regions in New York: (a) West Upstate, which includes Zones A through E; (b) East Upstate, which includes Zones F through I; (c) New York City, which is Zone J; and (d) Long Island, which is Zone K.

In each region, the two stations with the highest number of OOM dispatch hours during 2021 are shown separately from other stations (i.e., "Station #1" is the station with the highest number of OOM hours in that region during 2021, 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-105: Frequency of Out-of-Merit Dispatch

By Region by Quarter, 2020 - 2021



Region	Station Rank	Station Name
New York City	1	Astoria East Energy CC
	2	Arthur Kill
Long Island	1	East Hampton
	2	FPL Far Rock
East Upstate	1	Bethlehem
	2	Bowline
West Upstate	1	Black River Hydro
	2	Sithe Batavia

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-106 and Figure A-107 summarize the three categories of non-local reliability uplift that are allocated to all Load Serving Entities ("LSEs") and the four categories of local reliability that are allocated to the local Transmission Owner.

The three categories of non-local reliability uplift are:

- Day-Ahead Market – This primarily includes guarantee payments to generators that are economically committed in the day-ahead market. These generators receive payments when day-ahead clearing prices are not high enough to cover the total of their as-bid costs (includes start-up, minimum generation, and incremental costs). When a DARU unit is committed by the NYISO for statewide reliability, the resulting guarantee payments are uplifted statewide. However, these account for a very small portion of DARU capacity.

- Real-Time Market – Guarantee payments are made primarily to gas turbines that are committed by RTC and RTD based on economic criteria, but do not receive sufficient revenue to cover start-up and other running costs over their run time. Guarantee payments in the category are also made for: a) SRE commitments and out-of-merit dispatch that are done for bulk power system reliability; b) imports that are scheduled with an offer price greater than the real-time LBMP; and c) demand response resources (i.e., EDRP/SCRs) that are deployed for system reliability.

- Day-Ahead Margin Assurance Payment – Guarantee payments made to cover losses in margin for generators dispatched by RTD below their day-ahead schedules. When a unit has been dispatched or committed for local reliability, any day-ahead margin assurance payments it receives are allocated as local reliability uplift. However, the majority of day-ahead margin assurance payments are allocated as non-local reliability uplift.

The four categories of local reliability uplift are:

- Day-Ahead Market – Guarantee payments are made to generators committed in the SCUC due to Local Reliability Rule ("LRR") or as Day-Ahead Reliability Units ("DARU") for local reliability needs at the request of local Transmission Owners. Although the uplift from payments to these units is allocated to the local area, these commitments tend to decrease day-ahead prices. As a result of lower prices, more (non-local reliability) uplift is paid to generators that are economically committed before the local reliability pass.

- Real-Time Market – Guarantee payments are made to generators committed and redispatched for local reliability reasons after the day-ahead market. While this can occur for a variety of reasons, the majority of this uplift is related to Supplemental Resource Evaluation ("SRE") commitments.

- Minimum Oil Burn Compensation Program – Guarantee payments made to generators that cover the spread between oil and gas prices when generators burn fuel oil to help maintain reliability in New York City due to potential natural gas supply disruptions.

- Day-Ahead Margin Assurance Payment – Guarantee payments made to cover losses in margin for generators dispatched out-of-merit for local reliability reasons below their day-ahead schedules.

Figure A-106 & Figure A-107: Uplift Costs from Guarantee Payments

Figure A-106 shows the seven categories of uplift costs associated with guarantee payments on a monthly basis for 2020 and 2021. 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.

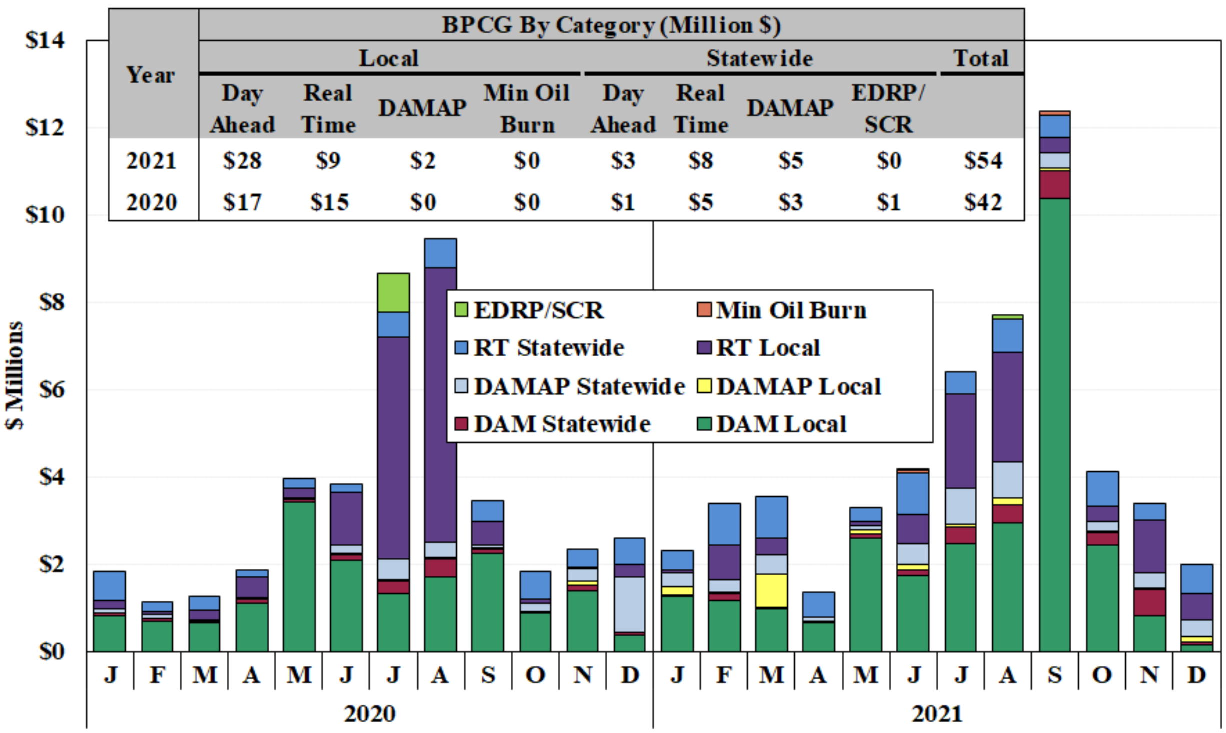
Figure A-107 shows the seven categories of uplift charges on a quarterly basis in 2020 and 2021 for four regions in New York: (a) West Upstate, which includes Zones A through E; (b) East Upstate, which includes Zones F through I; (c) New York City, which is Zone J; and (d) Long

Island, which is Zone K. The uplift costs paid to import transactions from neighboring control areas and EDRP/SCR resources are shown separately from the generation resources in these four regions in the chart. The table summarizes the total uplift costs in each region on an annual basis for these two years.

It is also noted that Figure A-106 and Figure A-107 are based on information available at the reporting time and do not include some manual adjustments resulting from mitigation consultations, hence, they can be different from final settlements.

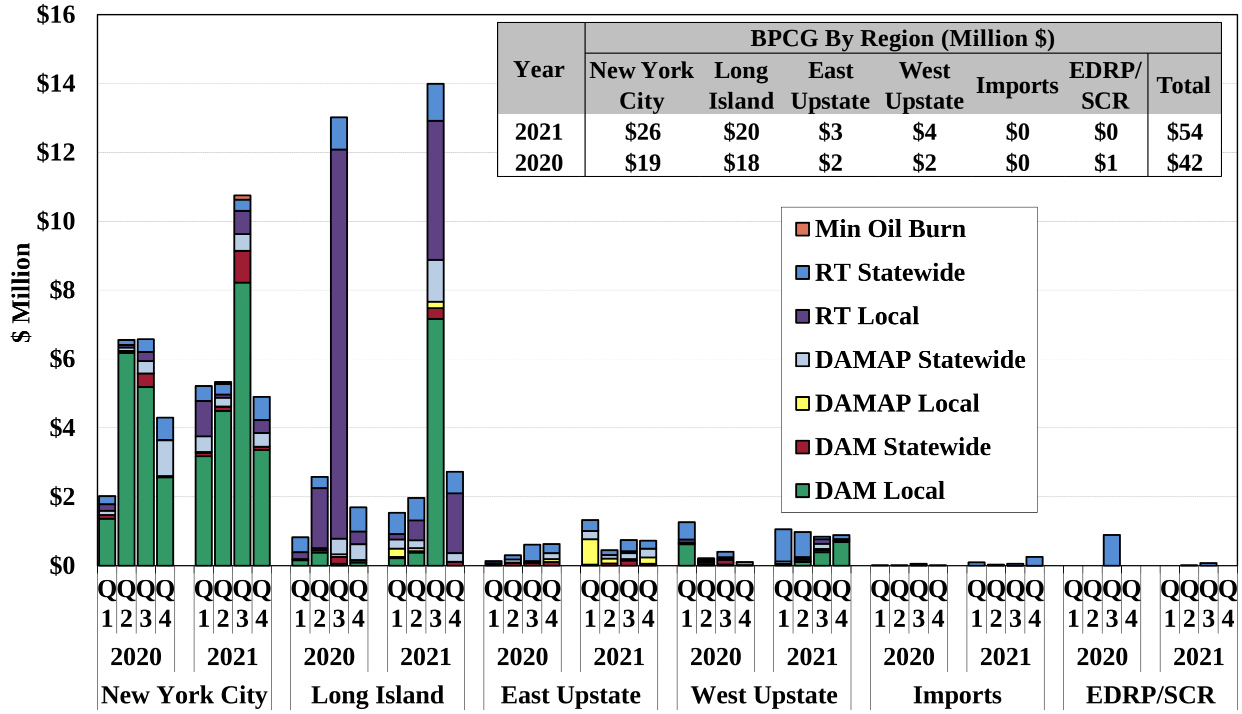
Figure A-106: Uplift Costs from Guarantee Payments by Month

2020 – 2021



Year	BPCG By Category (Million $)								
	Local				Statewide				Total
	Day Ahead	Real Time	DAMAP	Min Oil Burn	Day Ahead	Real Time	DAMAP	EDRP/ SCR	
2021	$28	$9	$2	$0	$3	$8	$5	$0	$54
2020	$17	$15	$0	$0	$1	$5	$3	$1	$42

Figure A-107: Uplift Costs from Guarantee Payments by Region
2020 – 2021



Year	BPCG By Region (Million $)						
	New York City	Long Island	East Upstate	West Upstate	Imports	EDRP/ SCR	Total
2021	$26	$20	$3	$4	$0	$0	$54
2020	$19	$18	$2	$2	$0	$1	$42

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 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-108, 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-108: Illustrative Diagram of the example system

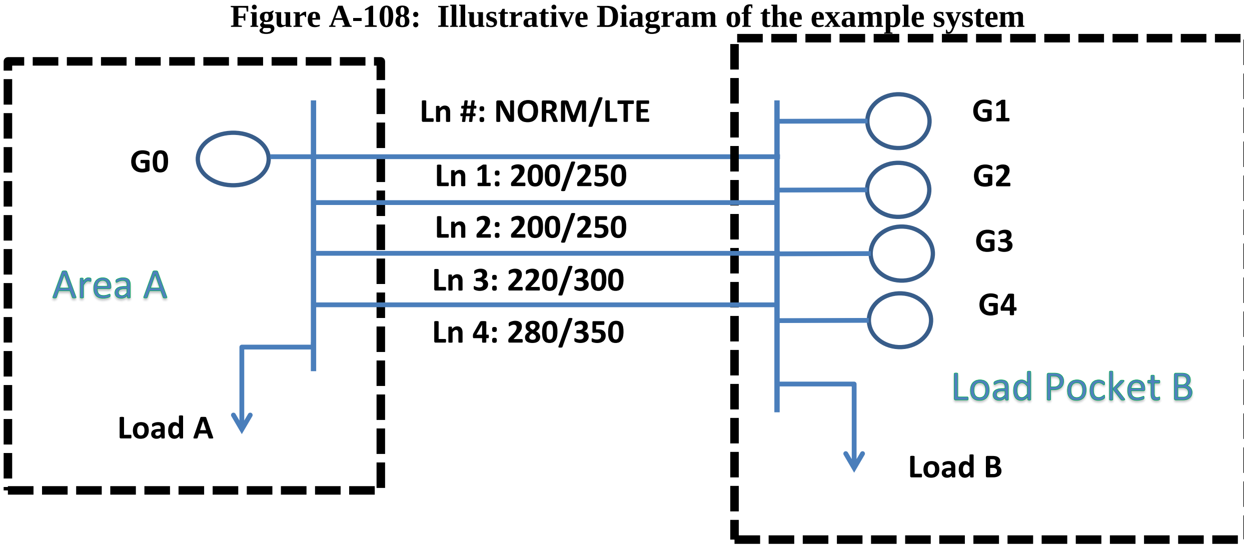


Table A-16 lists assumed physical parameters for the five generators in the example system. G0 represents the aggregation of less expensive generation in Area A, while G1 represents a slow-moving ST in the load pocket, which is also the largest generator in the pocket. G2 and G3 represent two CCs, and G4 represents a Bayonne-type facility that is capable of starting-up in 10 minutes.

Table A-16. 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-17 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-17: Generator Bids

Area	Generator	Min Gen	Inc Energy	10-Min Spin	10-Min Non-Spin	30-Min Reserve	60-Min Reserve
A	G0	$20	$20	$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-18:

Table A-18: 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	2015	230		255		$20	$1	$1	$0.5	$0
B	V1	100					$20				
	G1	75	0		45	100	$22.5	$3.5	$3.5	$3	$2
	G2	210	0		0	0	$24	$5	$5	$4.5	$3.5
	G3	200	0		0	0	$24	$5	$5	$4.5	$3.5
	G4	0		70			$24	$5	$5	$4.5	$3.5

These pricing outcomes are derived from the following binding constraints:

- Power balance constraint, with a shadow cost of $20/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 (2,1), with a shadow cost of $0.5/MWh;
- The constraint (3.1), with a shadow cost of $2.0/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,

- $Reserve\ Price\ Adder_{10min} = \begin{cases} SP_{1.1} + SP_{1.2} + SP_{2.1} + SP_{2.2} + SP_{3.1} + SP_{3.2} = \$\mathbf{4}, & i \in \{2,3,4\} \\ SP_{1.1} + SP_{2.1} + SP_{3.1} = \$\mathbf{2.5}, & i = 1 \end{cases}$

- $Reserve\ Price\ Adder_{30min} = \begin{cases} SP_{2.1} + SP_{2.2} + SP_{3.1} + SP_{3.2} = \$\mathbf{4}, & i \in \{2,3,4\} \\ SP_{2.1} + SP_{3.1} = \$\mathbf{2.5}, & i = 1 \end{cases}$

- $Reserve\ Price\ Adder_{60min} = \begin{cases} SP_{3.1} + SP_{3.2} = \$\mathbf{3.5}, & i \in \{2,3,4\} \\ SP_{3.1} = \$\mathbf{2.0}, & i = 1 \end{cases}$

- $LBMP\ Adder = \begin{cases} SP_{1.1} + SP_{1.2} + SP_{2.1} + SP_{2.2} + SP_{3.1} + SP_{3.2} = \$\mathbf{4}, & i \in \{2,3,4\} \\ SP_{1.1} + SP_{2.1} + SP_{3.1} = \$\mathbf{2.5}, & i = 1 \end{cases}$

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-19 shows the scheduling and pricing outcomes under the current market construct.

Table A-19: 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		$20	$1	$1	$0.5	
B	V1	100					$20				
	G1	75	0		0	0	$20	$1	$1	$0.5	
	G2	125	0		0	0	$20	$1	$1	$0.5	
	G3	120	0		0	0	$20	$1	$1	$0.5	
	G4	0		0			$20	$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 $20/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 2015 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 ($22.5 - $24/MWh in the pocket vs. $20/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 ($20/MWh vs. $22.5-$24/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 ($22.5/MWh vs $24/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.

M. Potential Design for Compensating Reserve Sellers that Provide Congestion Relief

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 its LTE if post-contingency actions would be available to quickly reduce flows to LTE after a contingency.[347] Post-contingency actions include deployment of operating reserves and adjustments to phase-angle regulators. The use of post-contingency actions is important

[347] See *NYISO Transmission and Dispatching Operations Manual*, Section 2.3.2.

because it allows the NYISO to increase utilization of the transmission system into load centers, thereby reducing production costs and pollution in the load center.

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 spite of providing valuable services especially during tight system conditions, these operating reserve suppliers are not currently compensated for helping manage congestion. This subsection describes a potential solution for the market to efficiently compensate these operating reserve providers.

The following equation describes a typical N-1 transmission constraint, k, that is used in the day-ahead and real-time market:

- $\sum_i \left(SF_i^k * Gen_i\right) \leq Limit_{N-1}^k$ (1)

For each relevant generator i for the constraint k, SF_i^k is the shift factor and Gen_i is the energy schedule. $Limit_{N-1}^k$ is the N-1 limit for the constraint, which could be set above its LTE rating because of the anticipated deployment of reserves post-contingency.

When operators estimate the additional up room from the LTE, available operating reserves that could help reduce post-contingency flows within 10 minutes are typically considered. As long as the total relief from 10-minute reserves is greater than or equal to the difference between $Limit_{N-1}^k$ and LTE^k, the post-contingency flows after the reserve deployment will be managed below the LTE. This translates to the following equation,

- $\sum_i [Min\left(0, SF_i^k\right) * 10MinReserve_i] \leq LTE^k - Limit_{N-1}^k$ (2)

When Equation (2) is modeled together with Equation (1), the shadow price of Equation (2) will reveal the economic value of 10-minute reserve providers that help manage congestion. Therefore, the market could compensate these reserve suppliers based on this shadow price, which will be in addition to other compensation that these reserve suppliers receive for satisfying systemwide and local reserve requirements.

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.[348] 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.[349]

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.[350] The amount of UCAP purchased is determined by the intersection of UCAP supply offers in the spot auction and the

348 The ICAP requirement = (1 + IRM) * Forecasted Peak Load. The IRM was set at 20.7 percent in the most recent Capability Year (i.e., the period from May 2021 to April 2022). NYSRC's annual IRM reports may be found at "http://www.nysrc.org/NYSRC_NYCA_ICR_Reports.html".

349 The locational ICAP requirement = LCR * Forecasted Peak Load for the location. The Long Island LCR was 103.4 percent from May 2020 to April 2021 and 102.9 percent from May 2021 to April 2022. The New York City LCR was 86.6 percent from May 2020 to April 2021 and 80.3 percent from May 2021 to April 2022. The LCR for the G-J Locality was set at 90.0 percent from May 2020 to April 2021 and 87.6 percent from May 2021 to April 2022. 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.

350 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.

demand curve (adjusted for capacity sales through bilateral contracts and forward auctions). Hence, the spot auction purchases more capacity than is necessary to satisfy the UCAP requirement when more capacity is available.

The demand curve for a capacity market Locality is defined as a straight line through the following two points:[351] 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. 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);
- Need for Financial Capacity Transfer Rights ("FCTRs") to incentivize merchant transmission projects (sub-section H); and

351 The demand curves also have maximum price levels which apply when UCAP procured falls substantially below the UCAP requirement. The demand curves for the 2020/21 and 2021/2022 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.

- Methods for assessing marginal capacity value for certain resource categories (sub-section I).

A. Installed Capacity of Generators in NYCA

Figure A-109 - Figure A-110: Installed Summer Capacity and Forecasted Peak Demand

The following two figures show the amount of installed capacity across the system and specifically within various regions of the state by fuel and technology type. The figures show the mix of resources in the system and how they have changed over time, generally shifting away from coal and nuclear (in more recent years) toward natural gas and renewable resources. With the retirement of the Indian Point nuclear units in 2020 and 2021, Eastern New York has become almost entirely dependent on fossil-fueled capacity with virtually all renewable, hydro, and nuclear resources in upstate regions.

The bottom panel of Figure A-109 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 2012 through 2022.[352, 353] The top panel of Figure A-109 shows the amount of capacity that entered or exited the market during each year.[354]

Figure A-110 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).

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352 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.

353 In this report, we have reconstituted the historic coincident and non-coincident peak demand values in both Figure A-109 and Figure A-110 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.

354 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-109: Installed Summer Capacity of Generation by Prime Mover
2012 – 2022

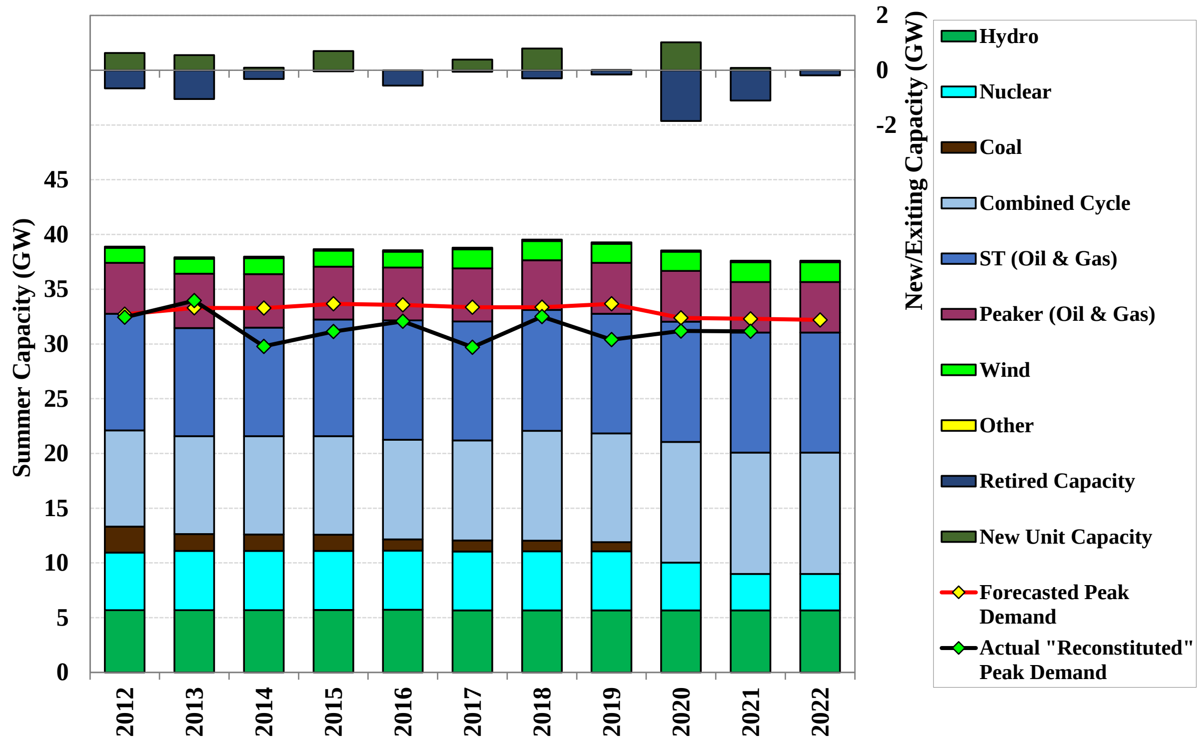
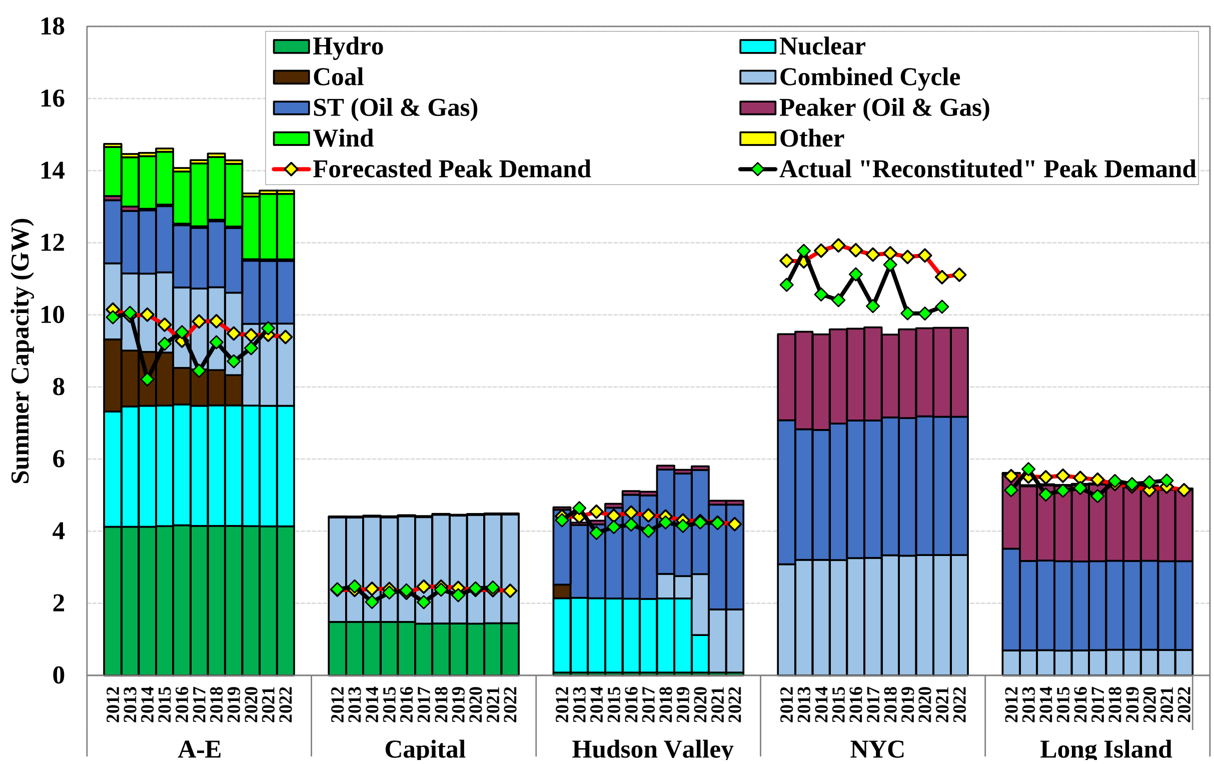


Figure A-110: Installed Summer Capacity of Generation by Region and by Prime Mover
2012 – 2022



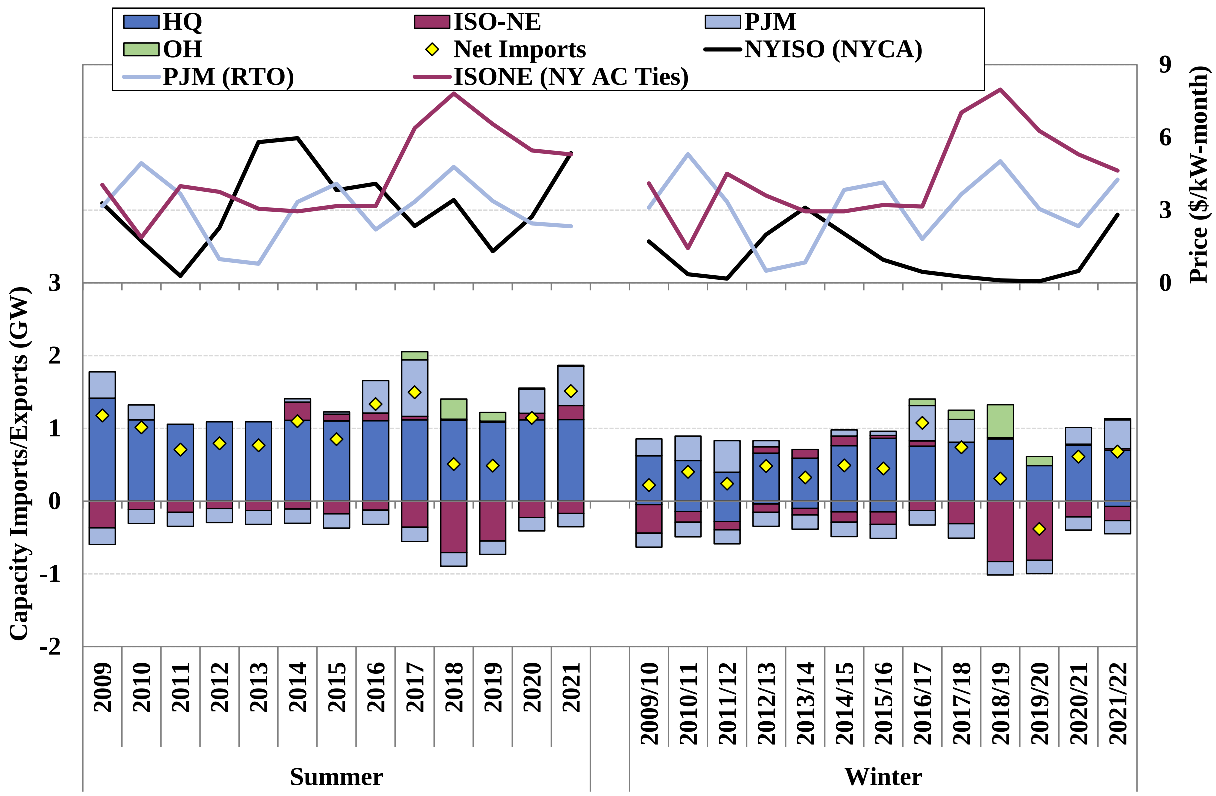
B. Capacity Imports and Exports

Figure A-111: NYISO Capacity Imports and Exports by Interface

The NYISO procures a portion of its installed capacity from neighboring regions, and some capacity on internal resources is sold to neighboring regions. The difference between the imports and exports serves as incremental (or decremental) capacity in the capacity market and, consequently, influences the prices outcomes of each auction.

Figure A-111 shows the monthly average of net capacity imports into the NYISO from neighboring control areas from Winter 2009/10 through Winter 2021/22 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.[355] 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.

Figure A-111: NYISO Capacity Imports and Exports by Interface
Winter 2009/10 – Winter 2021/22



355 The values for Winter 2021/22, reflect average net imports and average prices through January 2022.

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.[356] This gives suppliers a strong incentive to perform reliably.

The Locality-specific derating factors are used to translate ICAP requirements into UCAP requirements for each capacity zone. The NYISO computes the derating factor for each capability period based on the weighted-average EFORd of the capacity resources that are electrically located within the zone. For each Locality, a derating factor is calculated from the six most recent 12-month rolling average EFORd values of resources in the Locality in accordance with Sections 2.5 and 2.7 of the NYISO's Installed Capacity Manual.[357]

Table A-20: Historic Derating Factors by Locality

Table A-20 shows the derating factors the NYISO calculated for each capacity zone from Summer 2017 onwards. Derating factors tend to be highest in regions with the most internmittent capacity and most volatile year-over-year in regions with older generation fleets.

Table A-20: Derating Factors by Locality
Summer 2017 – Winter 2021/22

Locality	Summer 2021	Summer 2020	Summer 2019	Summer 2018	Summer 2017	Winter 2021/22	Winter 2020/21	Winter 2019/20	Winter 2018/19	Winter 2017/18
G-I	5.45%	5.77%	7.15%	4.92%	12.70%	8.41%	3.21%	6.87%	6.45%	11.72%
LI	4.91%	6.91%	6.47%	6.28%	5.60%	7.21%	5.91%	7.96%	6.90%	6.07%
NYC	2.69%	3.51%	4.09%	7.09%	4.37%	2.48%	2.70%	4.42%	5.98%	5.26%
A-F	13.27%	11.78%	12.50%	11.15%	11.94%	11.36%	9.63%	10.26%	8.93%	9.83%
NYCA	8.77%	8.30%	8.79%	8.56%	9.29%	8.40%	6.61%	8.00%	7.57%	8.43%

Figure A-112: Gas and Oil-Fired EFORds by Technology Type and Region

Both the age of a unit and the frequency at which it operates factors significantly into the eventual EFORd rating. Older units tend to be more prone to unanticipated forced outages and derates which drive EFORd ratings higher. On the other hand, operating at higher annual service hours tends to reduce the effects of outages on a unit's EFORd rating. Consequently, there can be large discrepancies between EFORd ratings on similarly aged resources in the same technology class based on how frequently they operate.

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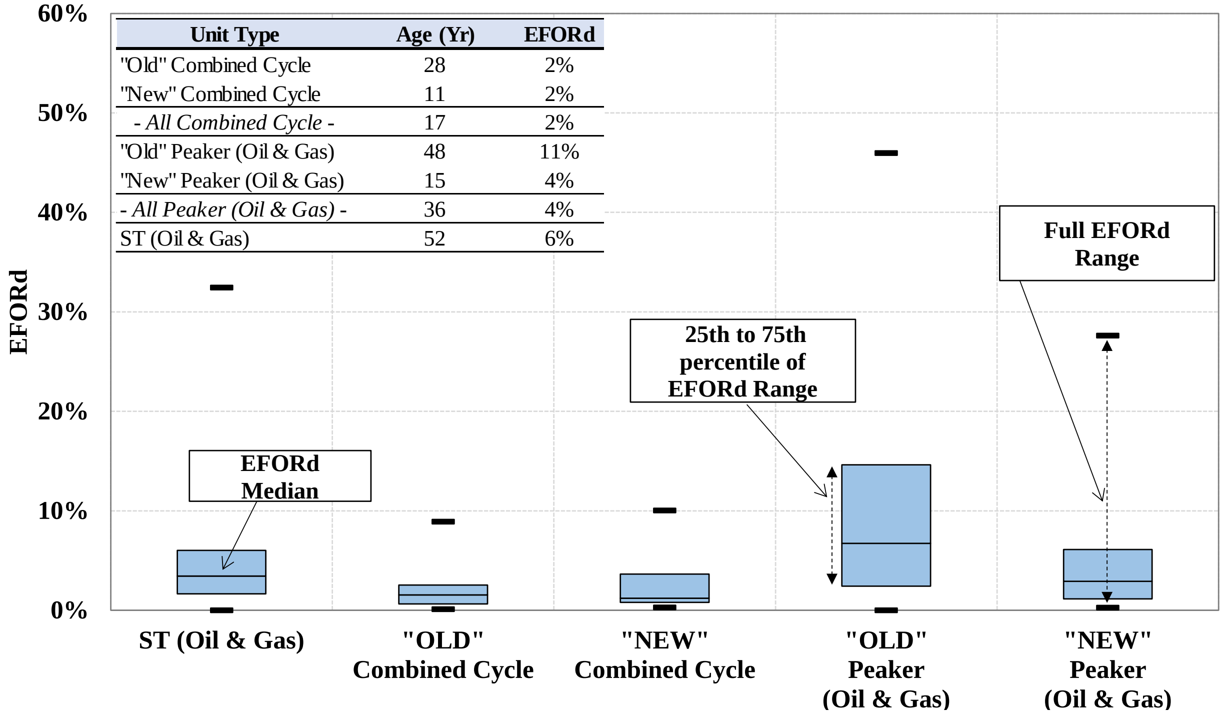
356 The variables and methodology used to calculate EFORd for a resource can be found here.

357 The Derating Factor used in each six-month capability period for each Locality may be found here.

Figure A-112 presents the distribution of EFORds of natural gas and oil-fired units based on technology type and age designation.[358] The column bars for each technology-age indicate the EFORd spread of the middle two quartiles (i.e. 25 to 75 percentile). The line inside each bar denotes the median value of EFORd for the specified capacity type. Each column is bounded by two dashed lines that denote the full range of observed EFORd values for the given technology. The table included in the chart gives the capacity-weighted average age and EFORd of each technology-age category.

Figure A-112: EFORd of Gas and Oil-fired Generation by Age

Summer – Five-Year Average



Unit Type	Age (Yr)	EFORd
"Old" Combined Cycle	28	2%
"New" Combined Cycle	11	2%
- All Combined Cycle -	17	2%
"Old" Peaker (Oil & Gas)	48	11%
"New" Peaker (Oil & Gas)	15	4%
- All Peaker (Oil & Gas) -	36	4%
ST (Oil & Gas)	52	6%

Table A-21: Illustrative EFORd Calculations for Service Hours Impact on Rating

Table A-21 provides illustrative representations of EFORd values for various technologies according to calculations consistent with data submitted in NERC GADS reporting process.[359] 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.”

358 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.”

359 Additional background on GADS can be found here.

- 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."

The table evaluates 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:

- **Steam Unit – Short Run Time:** A steam unit that operates for one day per start.
- **Steam Unit – Long Run Time:** A steam unit that operates for one week per start.
- **Peaking Unit:** Assuming it operates 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-21: 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 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%

Figure A-113: Unavailable Capacity to RTC & RTD from Various Technologies on Highest Load Days

The NYISO tariff at present utilizes a DMNC testing process to determine the ICAP ratings for traditional generators such as nuclear units, combined cycles, steam turbines, and peaking facilities.[360] The process is very similar in most ways across these unit, but take into consideration certain technology-specific characteristics in fine tuning testing obligations.[361] One such technology-specific obligation that exists is for "internal combustion, combustion units, and combined cycles" to temperature-adjust their DMNC test results based on an output factor curve that is dependent on one variable, ambient air temperaures, and a seasonal peak temperature rating determined by the previous Transmission District peak conditions across the most recent four like-Capability Periods. Functionally, this tends to mean that the ICAP ratings for these units types during the summer Capability Periods are lower than the value at which they test at since tests are often done at cooler temperatures than the seasonal peak.

The data in Figure A-113 below shows an an analysis of the 10-highest load days in the summer of 2021 that assesses availability of procured capacity from certain conventional resources on those days. The left side of the chart shows the data for the system as a whole whereas the right side shows the data for just Southeast NY. We evaluate, based on generator bids and performance during operation (where applicable), how much sold capacity was functionally unavailable to RTC and RTD when system load was highest for steam turbines, peakers, and nuclear stations based on the following categories:

- Emergency Capacity
  - Capacity offered above a generator's normal upper operating limit ("UOLn") that is only activated under NYISO Emergency Operations.[362]
- Ambient Water Limitation
  - The value of the derated capacity at certain generators that have indicated less availability due to higher water temperatures.
- Actual Underperformance at UOL
  - The drag of steam units when instructed to operate at their UOL in real-time for a minimum of 3-RTD intervals.
- Capacity Never Online
  - The installed capacity of generators that never operated on any of the 10-highest load days this year.

All of the capacity identified in this chart is sold to the market currently with equal weighting as anything else, i.e., with an assumed availability of one hundred percent. However, none of this capacity was available to the market in real-time during design conditions. ICAP ratings in the DMNC testing process and EFORd estimates should better account for this less reliable capacity

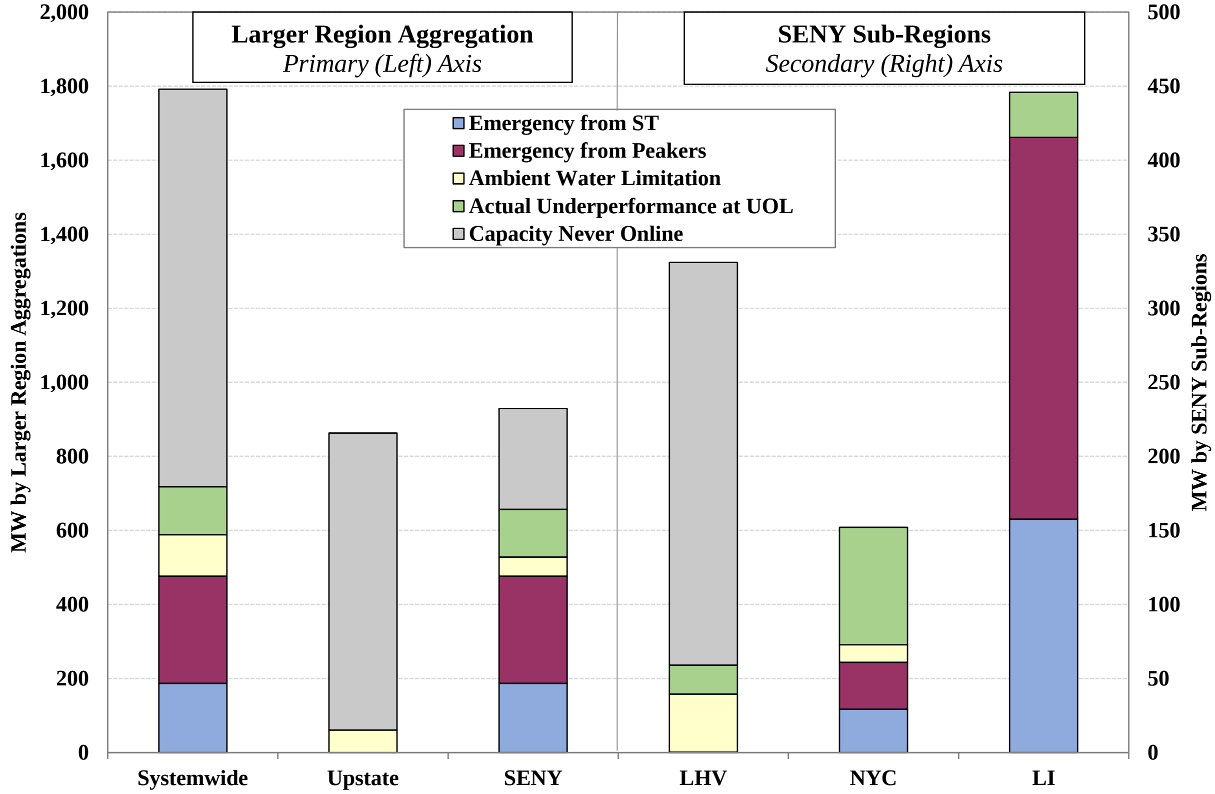
360 Section 5.12.1.2 of the Tariff establishes the DMNC test obligation on generators.

361 See Section 4.2 of the ICAP Manual.

362 See NYISO Emergency Operations Manual.

in determining both ICAP and UCAP values for traditional resources that may be less available than qualified under current requirements.

Figure A-113: Functionally Unavailable Capacity on Peak Load Days
Ten Highest Load days, 2021



D. Capacity Market Results: NYCA

Figure A-114: Capacity Sales and Prices in NYCA

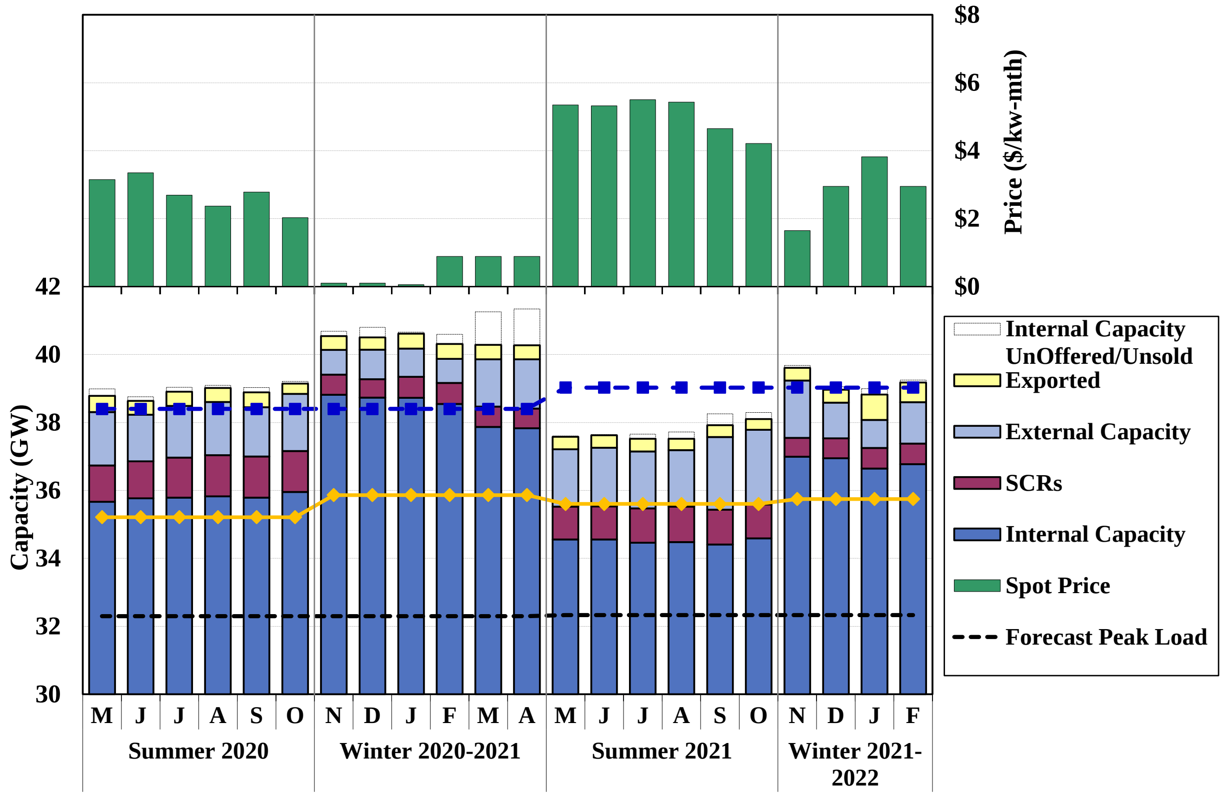
Figure A-114 shows capacity market results in the NYCA for the past four six-month Capability Periods. In the lower portion of each figure, the bars show the quantities of internal capacity sales, which include sales related to Unforced Deliverability Rights ("UDRs") and sales from SCRs.[363] The hollow 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-114 shows sales from external capacity resources into NYCA and exports of internal capacity to other

363 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.

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-114 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-114 also shows the forecasted peak load and the ICAP requirements.

Figure A-114: UCAP Sales and Prices in NYCA
May 2020 to February 2022



E. Capacity Market Results: Local Capacity Zones

Figure A-115 - Figure A-117: Capacity Sales and Prices in NYC, LI, and the G-J Locality

Figure A-115 to Figure A-117 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-114 does for the NYCA region and also compare the spot prices in each Locality to the Rest-Of-State prices.

In addition to the changes that affect the NYCA capacity requirements (e.g., forecasted peak load and the Derating Factors), requirements in the local capacity zones can also be affected by changes in the Local Capacity Requirement that are unrelated to load changes.

Figure A-115: UCAP Sales and Prices in New York City
May 2020 to February 2022

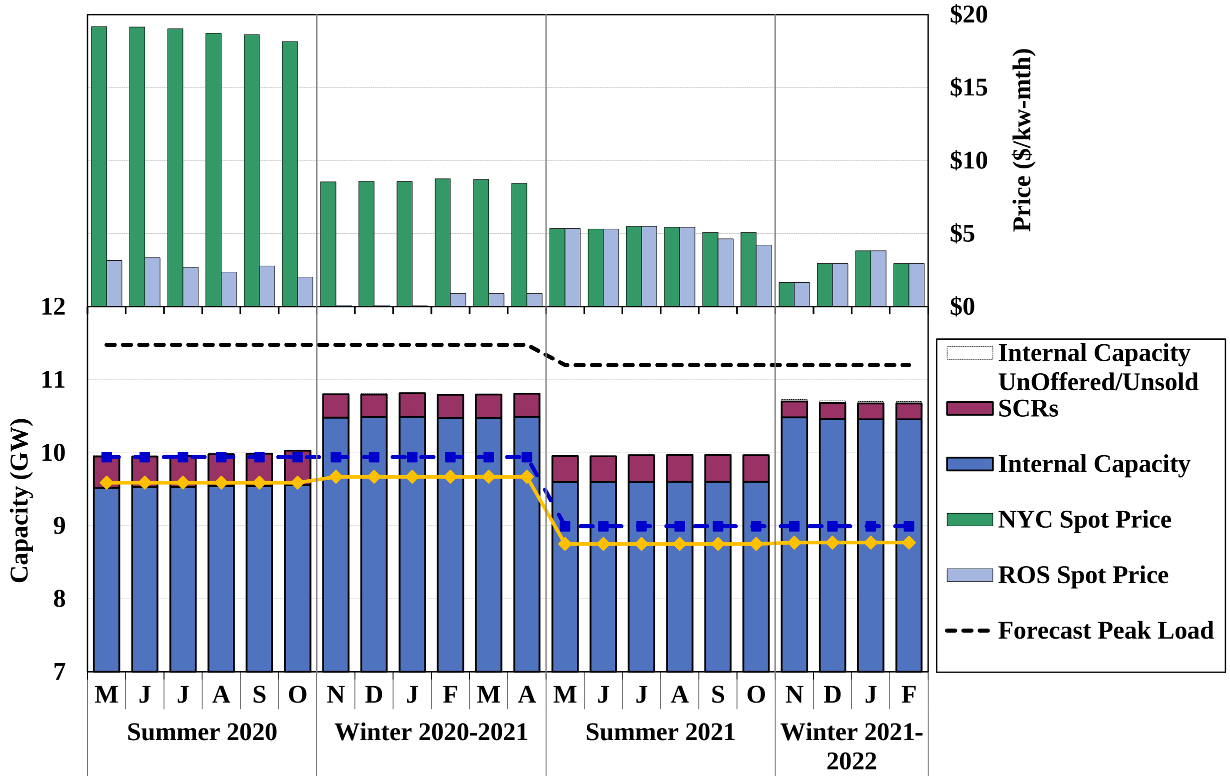


Figure A-116: UCAP Sales and Prices in Long Island
May 2020 to February 2022

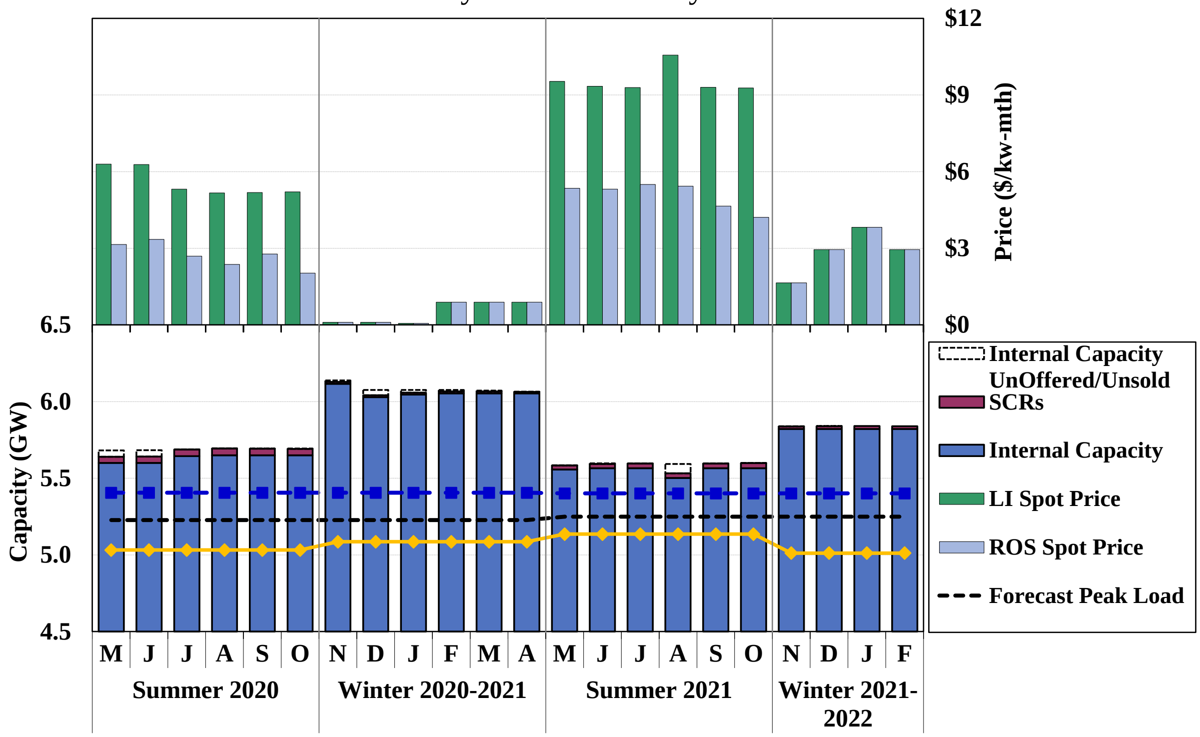


Figure A-117: UCAP Sales and Prices in the G-J Locality
May 2020 to February 2022

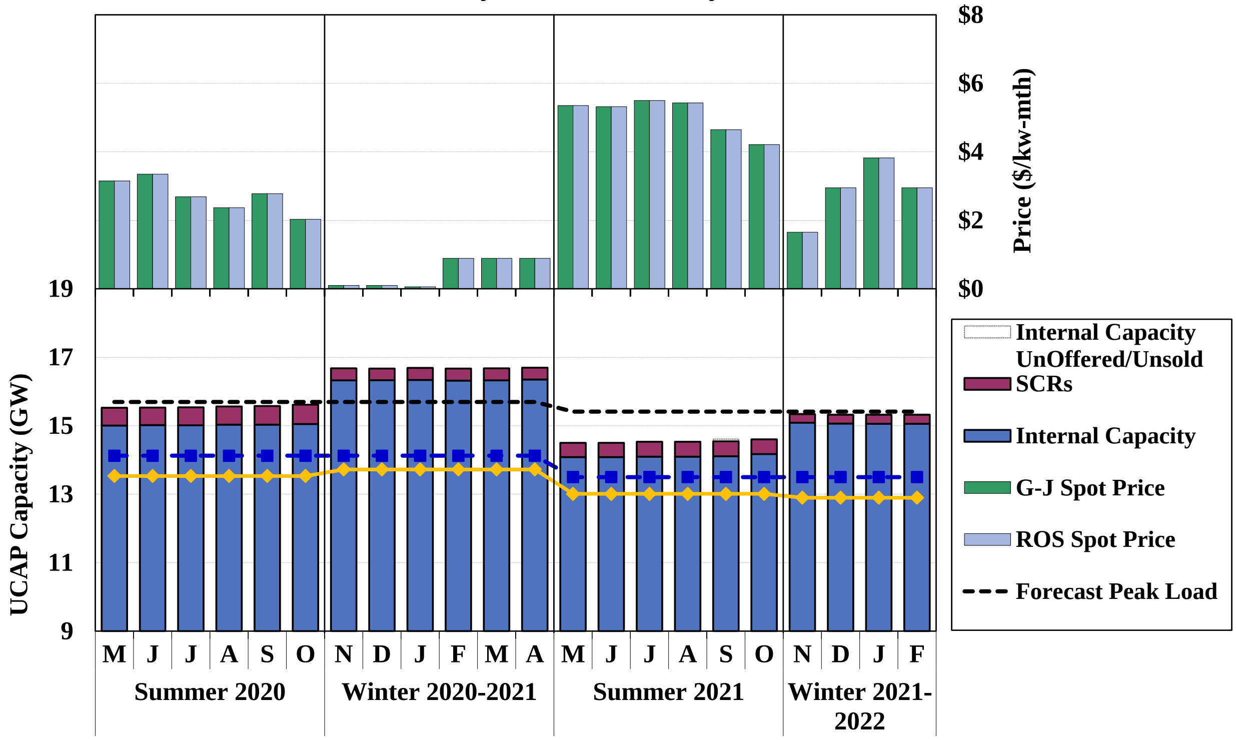
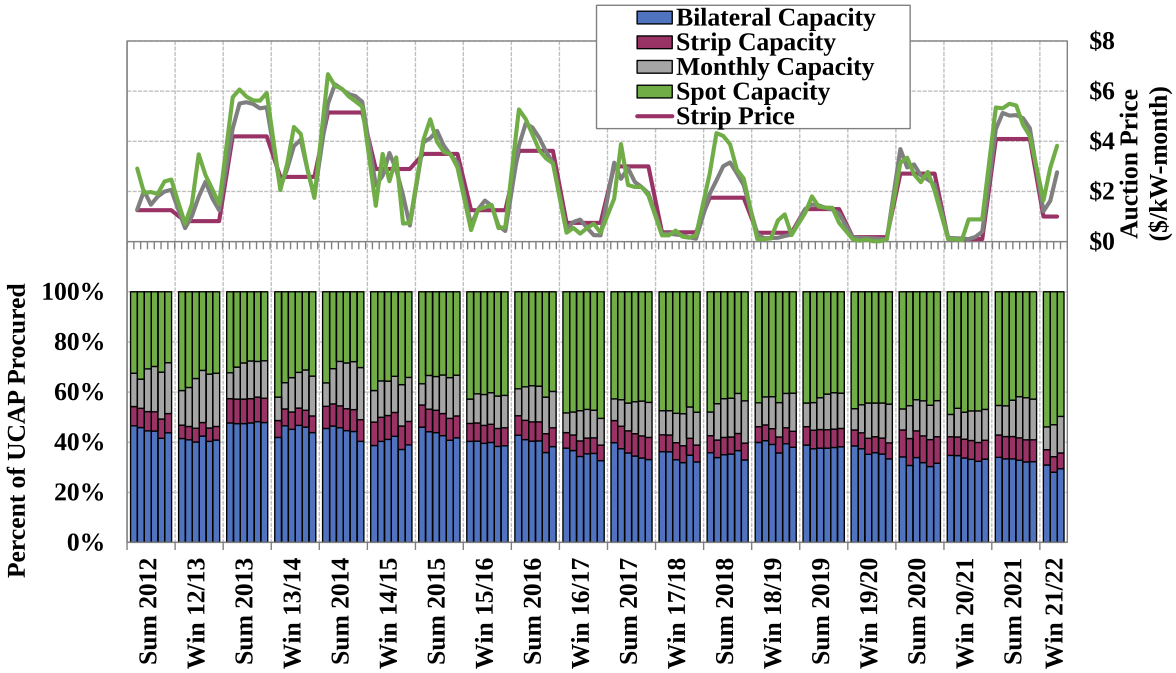


Figure A-118: Capacity Procurement by Type and Auction Price Differentials

Figure A-118 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 2012 capability period on a dollar-per-kilowatt-month basis.

Figure A-118: Auction Procurement and Price Differentials in NYCA
May 2012 – January 2022



F. Translation of 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 as we have recommended.[364] 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.

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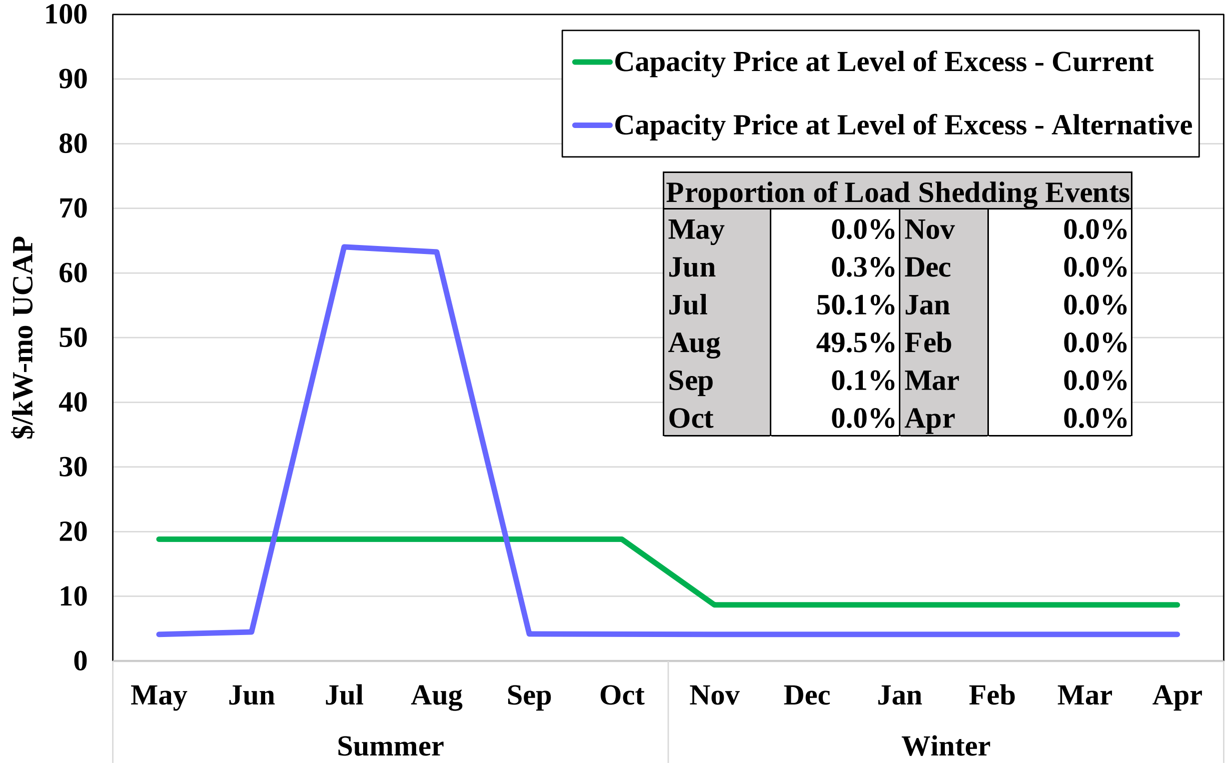
364 See Recommendation 2019-4 in Section XI.

Figure 33: Monthly Capacity Clearing Prices Compared to Capacity Value
At Level of Excess Conditions



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.

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-22: Cost of Reliability Improvement

Table A-22 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 0.055 in the 2022/23 Capability Year.[365] 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 2022/2023 Capability Year.
- *NYCA LOLE at Excess Level in Demand Curve Reset* – This is a single value for NYCA that is found by setting the capacity margin in each area to the Excess Level from the last demand curve reset.
- *LOLE from 100 MW UCAP Addition* – The estimated LOLE from placing 100 MW of additional UCAP in the area.[366]
- *Marginal Reliability Impact ("MRI")* – The estimated reliability benefit (reduction in LOLE) from placing 100 MW of additional UCAP in the area. This is calculated as the difference between the NYCA LOLE at Excess Level and the LOLE from adding 100 MW of UCAP to the area.

365 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.

366 These values were obtained by starting with the system at Excess Level with an LOLE of 0.0055 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.[367, 368] This is calculated based on the ratio of the *Net CONE of Demand Curve Unit* to the *MRI* for each area.

Table A-22: Cost of Reliability Improvement
2022/23 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	$86		0.044	0.0114	$0.8
B	$86		0.043	0.0114	$0.8
C	$86		0.051	0.0035	$2.5
D	$86		0.051	0.0035	$2.5
E	$86		0.051	0.0035	$2.4
F	$86		0.051	0.0034	$2.5
G-J Locality		0.055			
G	$114		0.051	0.0036	$3.1
H	$114		0.051	0.0036	$3.1
I	$114		0.051	0.0038	$3.0
NYC					
J	$164		0.050	0.0047	$3.5
Long Island					
K	$92		0.050	0.0050	$1.9

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.[369]

367 For example, for Zone F: $86/kW-year × 1000kW/MW ÷ (0.0034 LOLE change/100MW) × 0.001 LOLE change = $2.5 million.

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

369 See Recommendation 2012-1c in Section XI.

Figure A-119: Breakdown of Revenues for Generation and Transmission Projects

Figure A-119 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") project completed in 2016. The figure also compares the net revenues for these projects against their gross CONE and highlights the reduction in shortfall of revenues due to the proposed FCTRs. The ability to earn capacity revenues would have greatly improved the economic viability of the MSSC project, potentially rendering it competitive with generation solutions to providing reliability downstate. The information presented in the figure is based on the following assumptions and inputs:

- The MSSC project is assumed to increase UPNY-SENY transfer capability by 287 MW.[370]

- 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.371

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370 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.

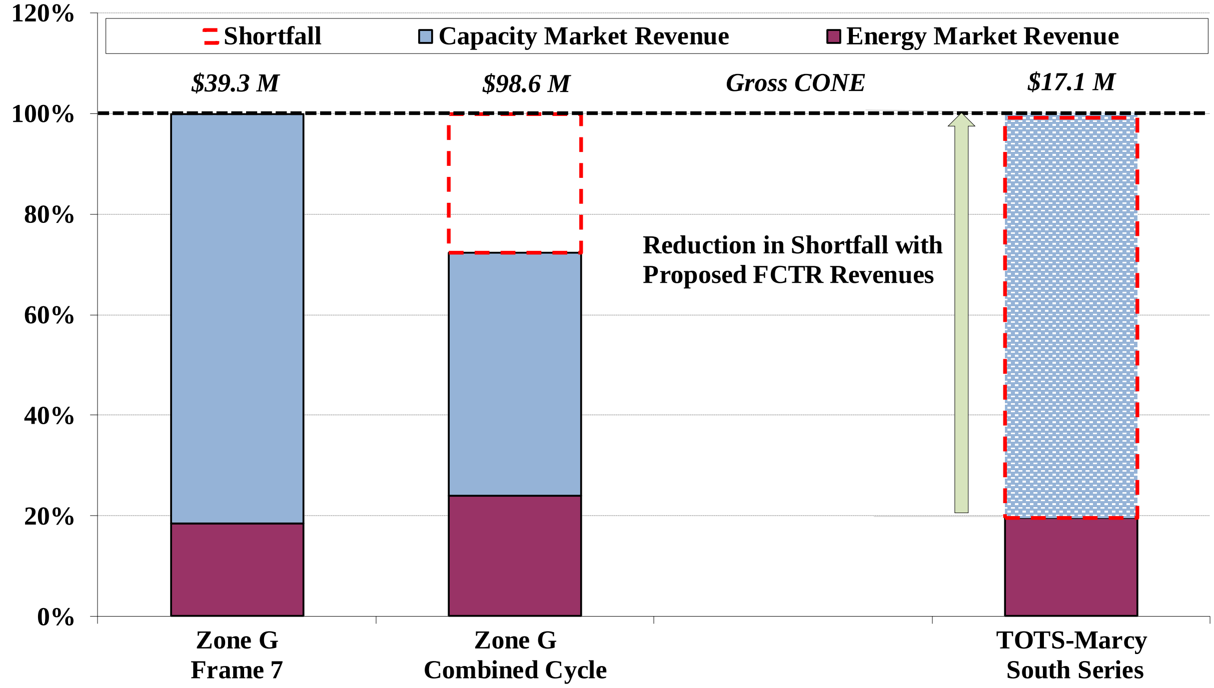
b) An investment cost of $120 million for the MSSC project (see here), inflated to 2019$.

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.

371 See NYISO Market Monitoring Unit's March 10, 2020 presentation to ICAPWG titled *Locational Marginal Pricing of Capacity – Implementation Issues and Market Issues*.

- The energy market revenues for the transmission projects are estimated using the value of incremental TCCs that were assigned to the MSSC project. Consistent with the 2019/20 Demand Curve annual update, the TCCs were valued based on the energy prices during September 2015 through August 2018.
- The gross CONE, energy and capacity market revenues for the Zone G Frame and CC units are based on the 2019/20 annual Demand Curve update.

Figure A-119: Breakdown of Revenues for Generation and Transmission Projects
At Level of Excess



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.

In early 2022, NYISO filed tariff revisions to revise its capacity accreditation approach beginning in the 2024/2025 capability year, and these were approved by FERC in May 2022. Under the new rules, Capacity Accreditation Factors will be calculated for each resource class (e.g. group of resources with similar characteristics) for each capacity zone. The Capacity Accreditation Factors will reflect the resource class's marginal reliability contribution, calculated using NYISO's resource adequacy model used to determine the IRM and LCRs.

NYISO currently does not adjust capacity credit for very large conventional generators or for units with common fuel supply limitations or 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.[372]

372 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 50-100 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.

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.[373] An example of an ELCC calculation, based on a recent proposal in PJM,[374] 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 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.

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373 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.

374 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.

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 investments 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 providing incentives for investors to:
  - Avoid technologies that have over-saturated the market. If an average or fixed credit is used, investors generally ignore this concern;
  - Add storage to intermittent renewables. If an average or fixed credit is used, the incentive to do this is greatly diminished;
  - Choose between storage projects with different durations by efficiently trading off cost and value to the system;
  - 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;
  - Efficiently repower renewable projects when they approach the end of their useful lives; and
  - Be more likely to retire existing generators without a reliable fuel supply during peak conditions rather than generators with fuel storage capability.
- 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.

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 land-based 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 XI) 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 from the market for four types of hypothetical gas-fired units:

- A new frame-type H-Class simple-cycle combustion turbine ("New CT") unit
- An existing Steam Turbine ("ST") unit
- An existing10-minute Gas Turbine ("GT-10") unit, and

- An existing 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 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.[375] 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. We also estimate historical capacity revenues based on spot capacity prices.

Table A-23 to Table A-25: 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.

- 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.[376] 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.

- 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:

375 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.

376 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.

Table A-23: Day-ahead Fuel Assumptions During Hourly OFOs[377]

Technology	Gas-fired	Dual Fuel
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.

- 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-24: Gas and Oil Price Indices and Other Charges by Region[378]

Region	Gas Price Index	Transportation & Other Charges ($/MMBTU)			Intraday Premium/ Discount
		Natural Gas	*Diesel/ ULSD*	*Residual Oil*	
West	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	Iroquois Zn2	$0.27	$1.50	$1.00	10%
New York City	Transco Zn6	$0.20	$1.50	$1.00	20%
Long Island	Iroquois Zn 2	$0.25	$1.50	$1.00	30%

- Regional Greenhouse Gas Initiative ("RGGI") compliance costs are considered for all years.

- The minimum generation level is 90 MW for the ST unit. At this level, its heat rate is 13,000 btu/kWh. 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 and operating and cost assumptions are listed below.

377 **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.

378 The analysis assumes that the units in New York City region would switch from Transco Zn6 to Iroquois Zn2 when the Transco Zn6 pipeline is congested.

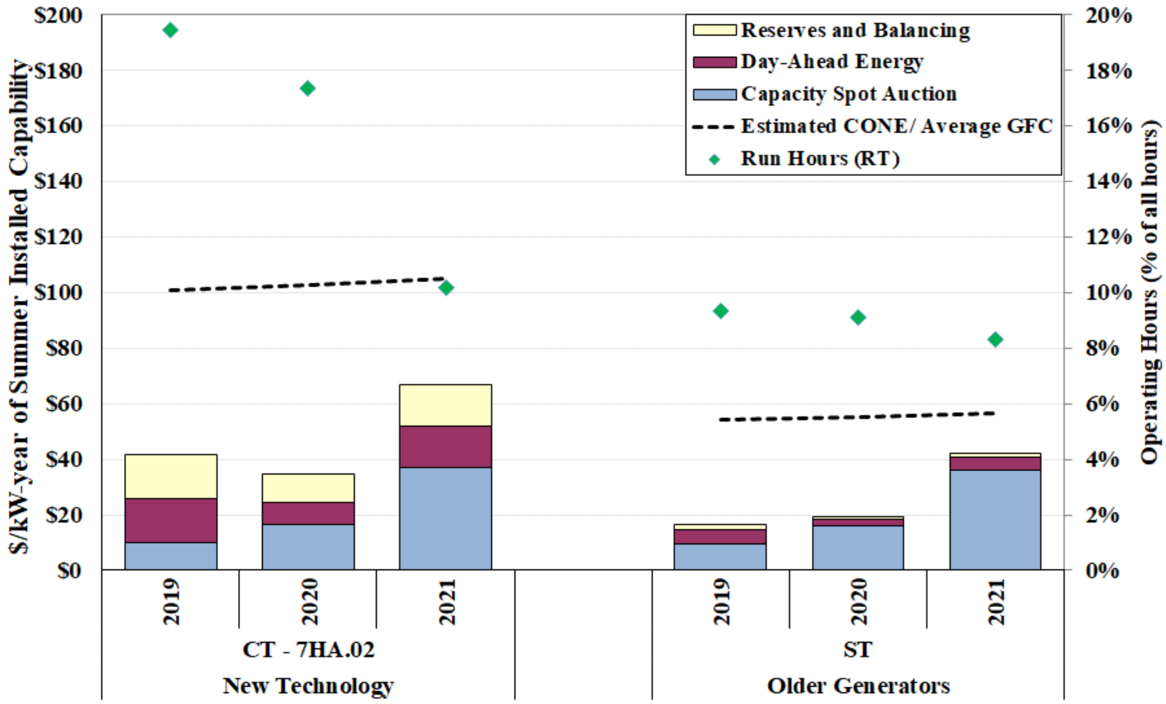
Table A-25: Gas-fired Unit Parameters for Net Revenue Estimates[379]

Characteristics	ST	GT-10	GT-30	New CT
Summer Capacity (MW)	360	32	16	358
Winter Capacity (MW)	360	40	20	370
Heat Rate (Btu/kWh)	10000	15000	17000	9300
Min Run Time (hrs)	24	1	1	1
Variable O&M (2021$/MWh)	$10.1	$5.1	$6.2	$1.4
Startup Cost (2021$)	$6,770	$1,354	$585	$26,600
Startup Cost (MMBTU)	3500	50	60	490
EFORd	5.14%	10.46%	19.73%	4.30%

Figure A-120 to Figure A-124: 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. Net revenues and CONE values are shown per kW-year of Summer Installed Capability.

Figure A-120: Net Revenue & Cost for Fossil Units in West Zone
2019-2021



379 The parameters for the new CT are based on the recent NYISO ICAP Demand Curve reset study. 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.*

Figure A-121: Net Revenue & Cost for Fossil Units in Capital Zone
2019-2021

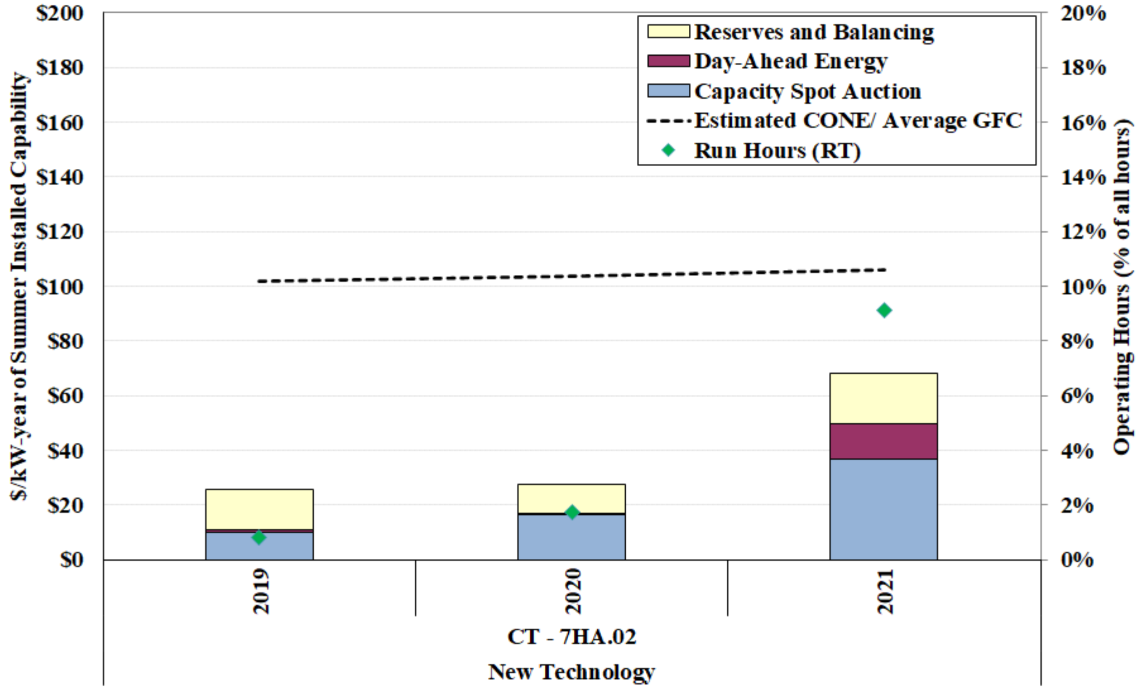
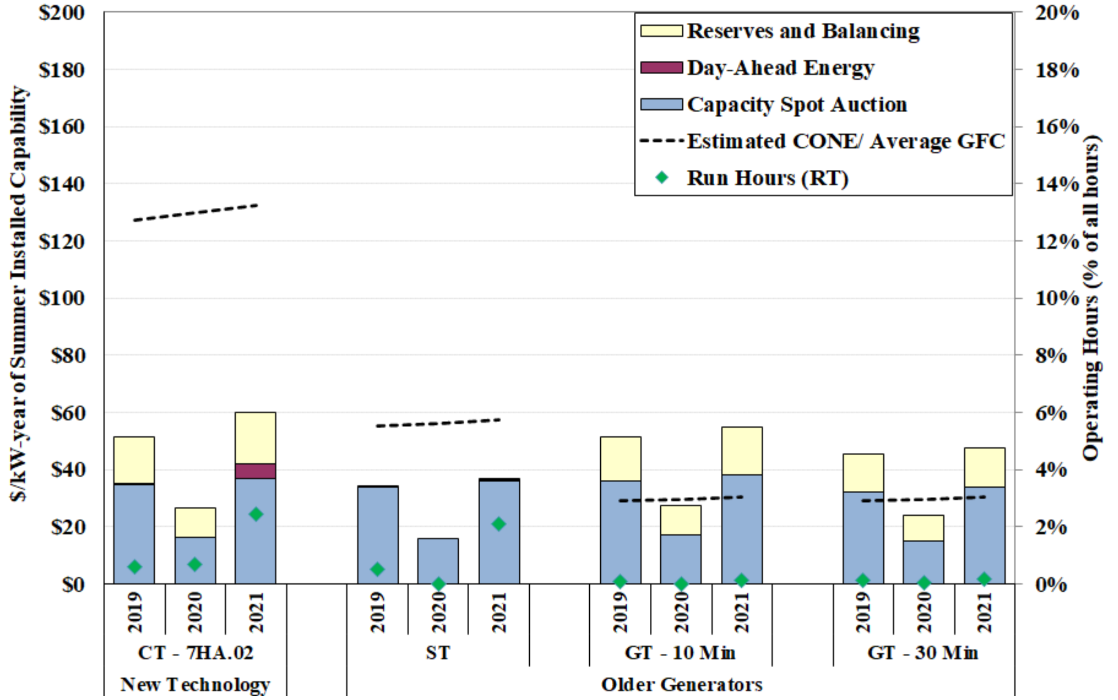


Figure A-122: Net Revenue & Cost for Fossil Units in Hudson Valley[380]
2019-2021



380 Net revenues use Iroquois Z2 gas prices for new technologies interconnecting in Dutchess County.

Figure A-123: Net Revenue & Cost for Fossil Units in New York City
2019-2021

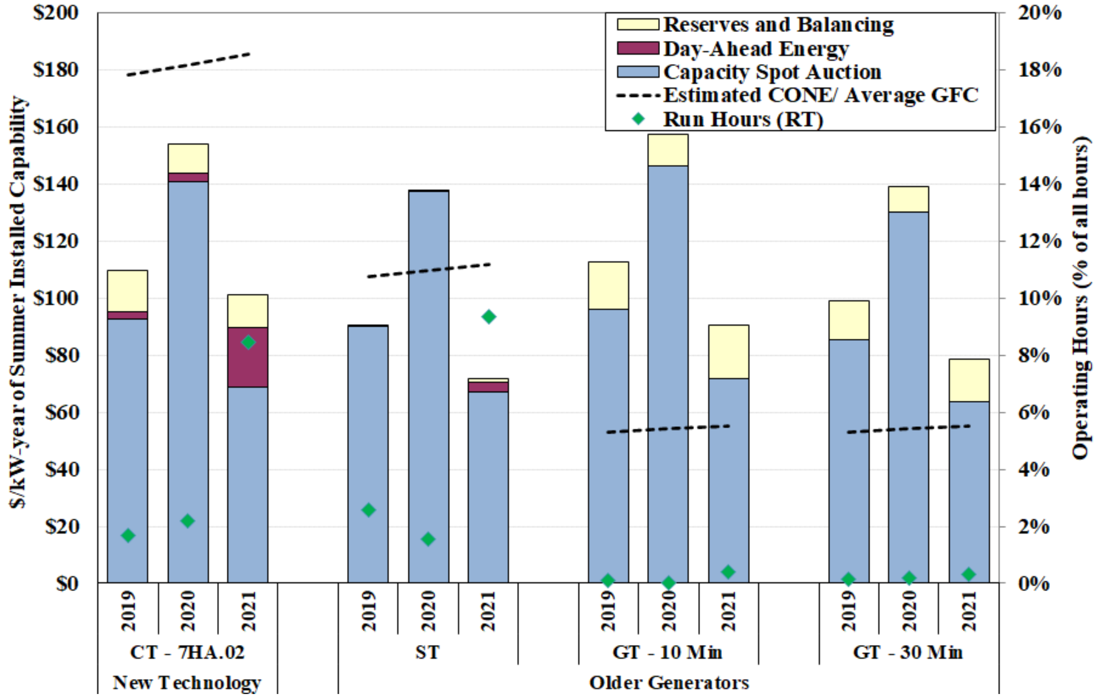
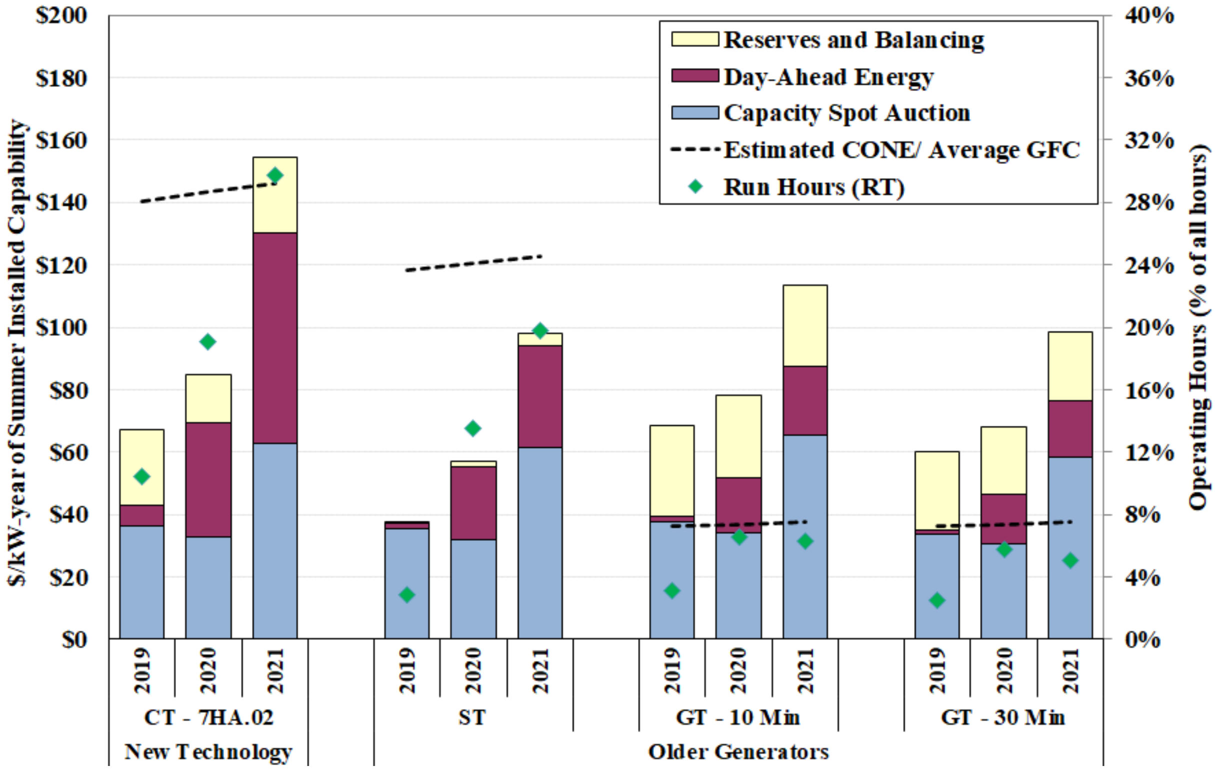


Figure A-124: Net Revenue & Cost for Fossil Units in Long Island
2019-2021



B. Nuclear Unit Net Revenues

We estimate the net revenues the markets provide to the nuclear plants in the Genesee and Central Zones. The estimates are based on LBMPs at the Ginna bus (for Genesee), and the Fitzpatrick and Nine Mile Unit 1 buses (for Central Zone).

Figure A-125: Net Revenues for Nuclear Plants

Figure A-125 shows the net revenues and the US-average operating costs for the nuclear units from 2019 to 2021. Estimated net revenues are based on the following assumptions:

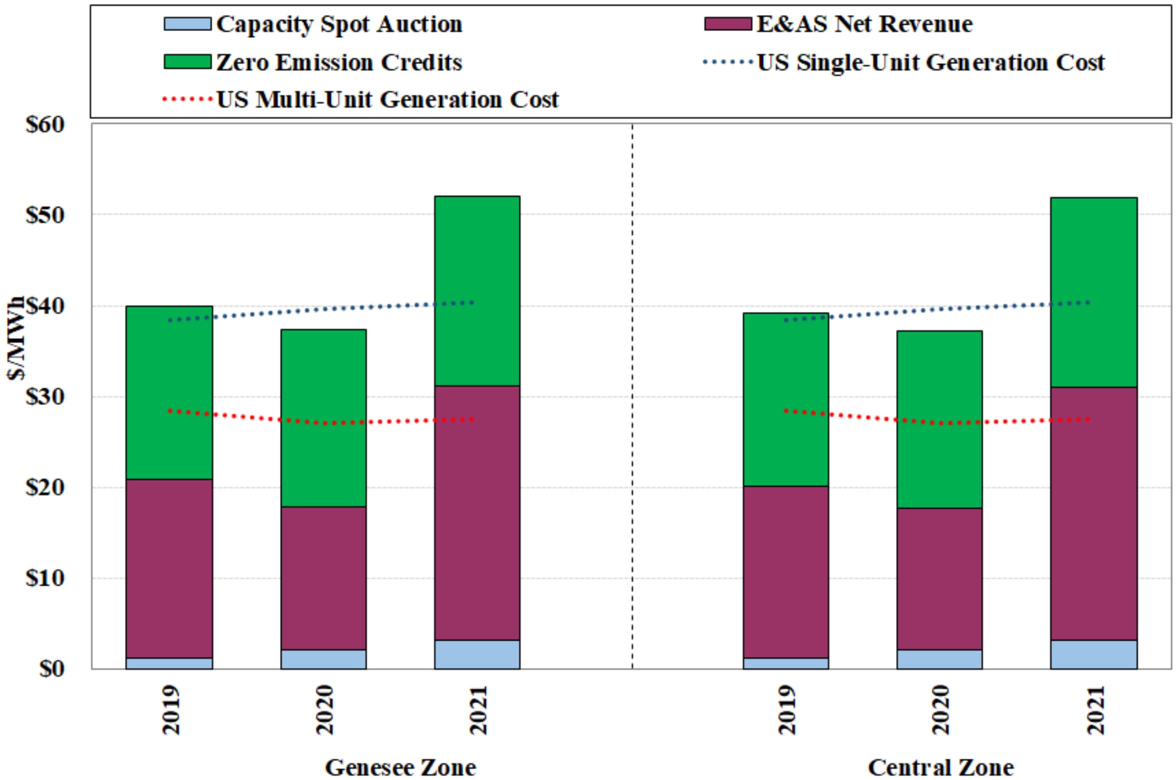
- Nuclear plants are scheduled day-ahead and only sell energy and capacity.
- Nuclear units earn energy revenues throughout the year except during periods of forced outages and outages related to refueling. We assumed an EFORd of two percent and a capacity factor of 67 percent during March and April to account for reduced output during refueling.[381]
- 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 2019 through 2020.[382]
- The nuclear units located in upstate zones are eligible for additional revenue in the form of Zero Emission Credits ("ZECs").[383] 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.

381 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.

382 The average cost of operation of nuclear plants in the US are based on NEI/ EUCG reports and presentations. See here.

383 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 capacity and energy prices above a threshold of $39/MWh.

Figure A-125: Net Revenue of Existing Nuclear Units
2019-2021



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-26 and Figure A-126: Costs, Performance Parameters, and Net Revenues of Renewable Units

Our methodology for estimating net revenues and the CONE for utility-scale solar PV and land-based 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.[384]

- The capacity revenues for solar PV, land-based wind, and offshore wind units are calculated using prices from the spot capacity market. The capacity values of renewable resources are based on the factors (30, 2, and 50 percent for Winter Capability Periods and 16, 46, and 30 percent for Summer Capability Periods for land-based wind, solar PV, and offshore wind, respectively) specified in the February 2021 NYISO Installed Capacity Manual.[385]

- We estimated the value of Renewable Energy Credits ("RECs") produced by utility-scale solar PV and land-based wind units using annual Tier 1 REC sale prices published by NYSERDA for the years 2018 through 2021.[386] Offshore REC ("OREC") prices were derived from the Index OREC values and calculation methodology in NYSERDA's public purchase and sale agreements with projects selected in its 2020 offshore wind solicitation.[387]

- Solar PV, offshore wind, and land-based 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.[388] We

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384 Assumed yearly capacity factors for solar PV, land-based wind, 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.

385 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."

386 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 2021 Compliance Year is $22.34/MWh.

387 See Appendix A and B of NYSERDA's October 2019 "Launching New York's Offshore Wind Industry: Phase I Report".

388 For solar PV, the ITC was 30 percent for projects that began construction in 2019 or earlier. The safe harbor period for the projects is up to four years. Consequently, for the timeframe of our analysis, we assumed 30 percent ITC for solar PV projects.

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 land-based wind projects is 100 percent for projects beginning construction before 2017 and 80 percent in 2017. As the developers of land-based wind can safe harbor incorporate the value of these federal incentives as an additional revenue stream for solar PV and wind units.[389]

- 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-26 shows cost estimates for solar PV, land-based wind and offshore wind units we used for a unit that commence operations in 2021. The data shown are largely based on Renewable Technology Costs study.[390] The table also shows the capacity factor and capacity value assumptions we used for calculating net revenues for these renewable units.

their investments for a maximum of four calendar years and receive PTC, we assumed 100 percent PTC for projects coming in service in 2019 and 2020, and we assumed 80 percent PTC for projects entering in service in 2021. The PTC is available only for the first 10 years of the project life. The value of PTC shown is levelized on a 20-year basis using the after-tax WACC.

389 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.

390 The assumed investment costs and fixed O&M costs for solar PV, land-based wind and offshore wind are based on the NYISO's study on Renewable Technology Costs, see here. The assumed investment cost trajectory over the years for land-based wind, solar PV, and offshore wind units was based on "Moderate" cost curves from 2021 NREL ATB. We used TRG 6 cost decline curve for land-based 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 land-based 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.

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 land-based wind are utilized from CES whitepaper, see here.

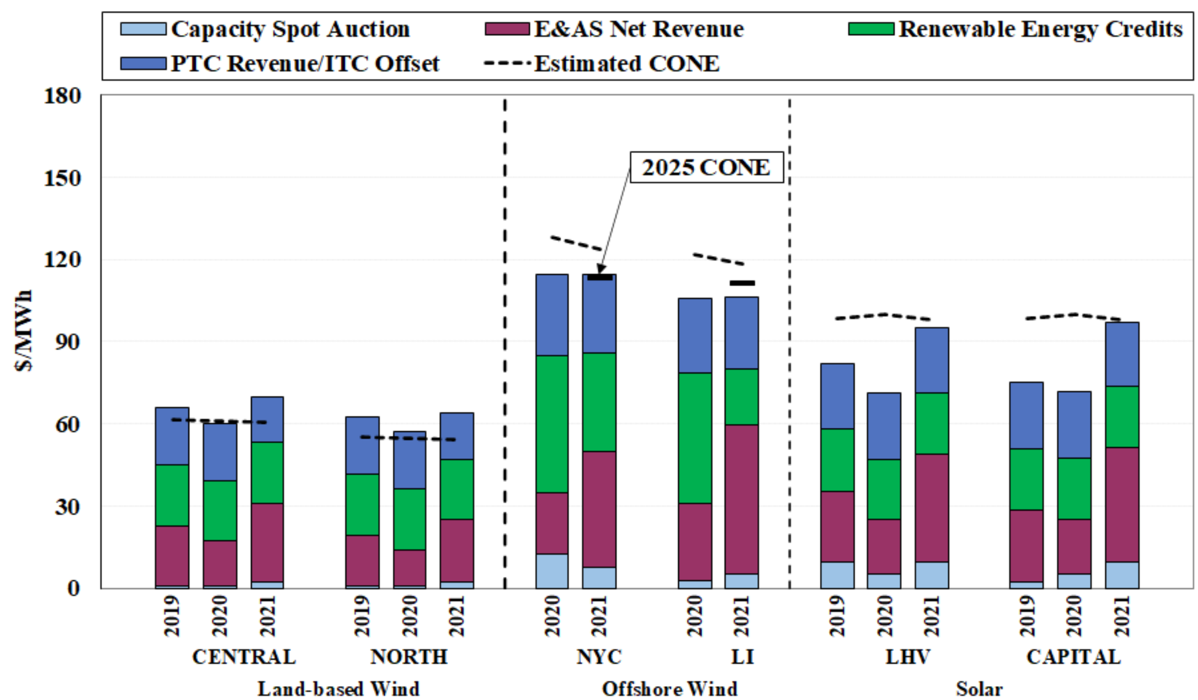
We assume construction lead time (i.e. time taken by a unit from commencement of its construction to commercial operation) of 1 year for solar PV plant and 3 years for land-based and offshore wind plants.

Table A-26: Cost and Performance Parameters of Renewable Units

Parameter	Utility-Scale Solar PV	Land-based Wind	Offshore Wind
Investment Cost (2021$/kW AC basis)	*Capital/LHV*: $1328	*Upstate NY*: $1557	*NYC/Long Island* : $4120
Fixed O&M (2021$/kW-yr)	$27	$48	$120
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)	*Land-based Wind and Solar PV:* ***2021*** *- $22.34* ***2020*** - $22.09 ***2019*** - $22.43 *Offshore Wind:* Calculated using the 2020 Offshore Wind Solicitation Indexed REC strike price of $86/MWh NYC / $80/MWh LI (2021$) less energy and capacity prices.		

Assuming the operating and cost parameters shown in the table above, Figure A-126 shows the net revenues and the estimated CONE for each of the units during years 2019-2021. 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.

Figure A-126: Net Revenues of Solar, Land-based Wind and Offshore Wind Units
2019-2021



D. Impact of Market Enhancements on Investment Signals and Consumer Costs

Section XI of the report discusses several recommendations that are aimed at enhancing the pricing and performance incentives in the real-time markets. Implementing these recommendations would improve the efficiency of energy and reserve market prices and help direct investment to the most valuable resources and locations. In this subsection, we illustrate the impacts of implementing a subset of our real-time market recommendations on: (a) the mix of energy and capacity market revenues, (b) the long-term investment signals of various resource types in several Zone J 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 units.

NYISO is pursuing market design and implementation projects that would fully or partially address several of these recommendations. Table A-27 below indicates the ongoing NYISO effort that is most closely associated with each recommendation.

Table A-27: NYISO Projects Addressing Real Time Pricing Recommendations

Recommendation		NYISO Project	Status
2016-1	Compensate operating reserve units that provide congestion relief		
2017-1	Model local reserve requirements in NYC load pockets	Dynamic Reserves	NYISO performed initial study of dynamic reserve modeling in 2021. Ongoing effort.
2017-2	Enhance operating reserve demand curves	Ancillary Services Shortage Pricing	NYISO implemented revised demand curves that partially addessed this recommendation in 2021.

We estimated the impact of the following four enhancements affecting New York City by adjusting the 2019-2021 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.[391]

- 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

391 See Appendix V.B and discussion of recommendation 2016-1 in Section XI of the report.

prices by an amount equal to the BPCG per MW-day of the UOL for DARU and LRR-committed units.[392]

- 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 $4.9/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.[393]

- 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.

Table A-28: Assumptions for Operating Characteristics of Repowered Combined Cycle and Grid-scale Storage Units

The technologies we considered for this analysis and their assumed operating characteristics are as follows:[394]

- 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 Battery Storage – We studied a grid-scale battery 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-28.

392 See Section V.J of the Appendix and discussion of recommendation 2017-1 in Section XI 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 $2.34/MWh in most areas to as much as $3.64 in the Astoria West/Queensbridge load pocket in 2021. The estimated price adder for each day was applied to LBMPs and reserve prices in hour 16.

393 This value corresponds to (1) increased shortage prices at several reserve demand curve quantities adopted 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. $4.9/kW-year net revenue impact is estimated using the average of the annual net revenues values over the years 2018, 2019, and 2021.

394 The CONE estimates for new technologies assume units would commence operations in 2021.

Table A-28: Operating Parameters and CONE of Battery Storage Unit[395]

Characteristics	Storage
Gross CONE (2021$/kW-yr)	$232
Technology	Li-ion Battery
Service Life (Years)	20
Withdrawal (4 Hrs)	Lowest priced hours each day
Injection (4 Hrs)	Highest priced hours each day
Reserve Selling Capability	10-min spin
Roundtrip Efficiency	85%
EFORd	2%
Capacity Value	90%

Figure A-127: Impacts of Real Time Pricing Enhancements on Net Revenues of NYC Demand Curve unit under Long-term Equilibrium Conditions

In addition to improving the efficiency of energy and reserve prices, implementing real time market enhancements could also shift payments from capacity to energy markets. Under long-term equilibrium conditions, an increase in the E&AS revenues of the demand curve unit would translate into reduced capacity prices for all resources operating in the market.

To determine the impact on Annual ICAP Reference Value, we estimated net CONE of the Frame unit under two scenarios with the system at the tariff-prescribed Level of Excess conditions modeled in the ICAP demand curve reset.[396] Figure A-127 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.

395 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*.

396 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*.

Figure A-127: Impact of Price Enhancements on Net Revenues of NYC Demand Curve
At Level of Excess Conditions

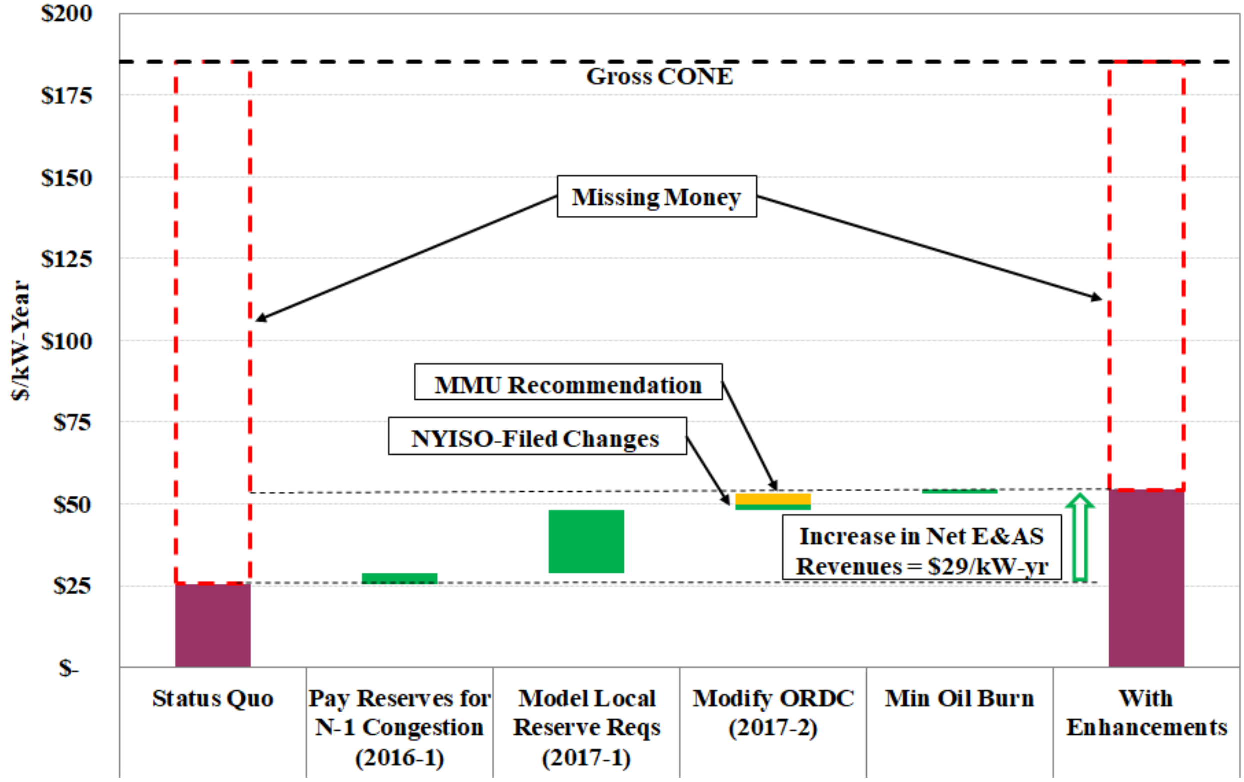


Figure A-128 to Figure A-131: Impacts of Real Time Pricing Enhancements on New York City Net Revenues

Figure A-128 through Figure A-131 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 reflect a capacity price consistent with the average excess observed in the years 2019 through 2021.

Figure A-128: Impact of Pricing Enhancements on Net Revenues - New York City

At Current Excess

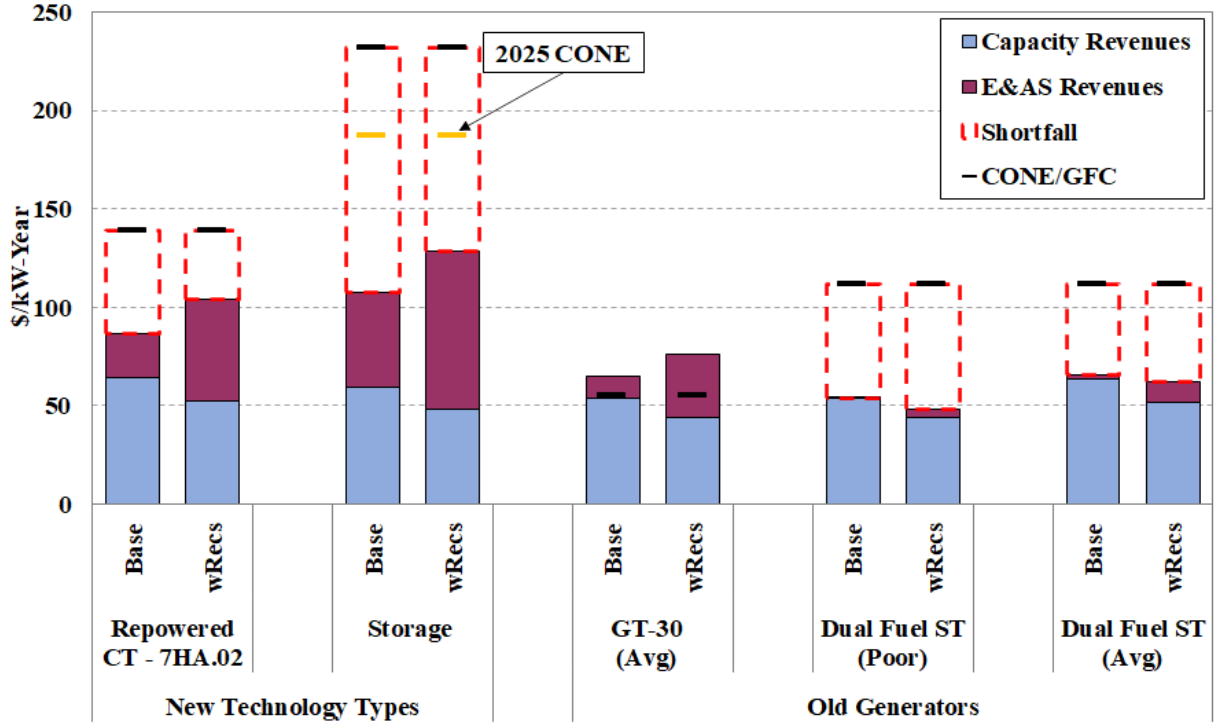


Figure A-129: Impact of Pricing Enhancements on Net Revenues – NYC Load Pocket #1

At Current Excess

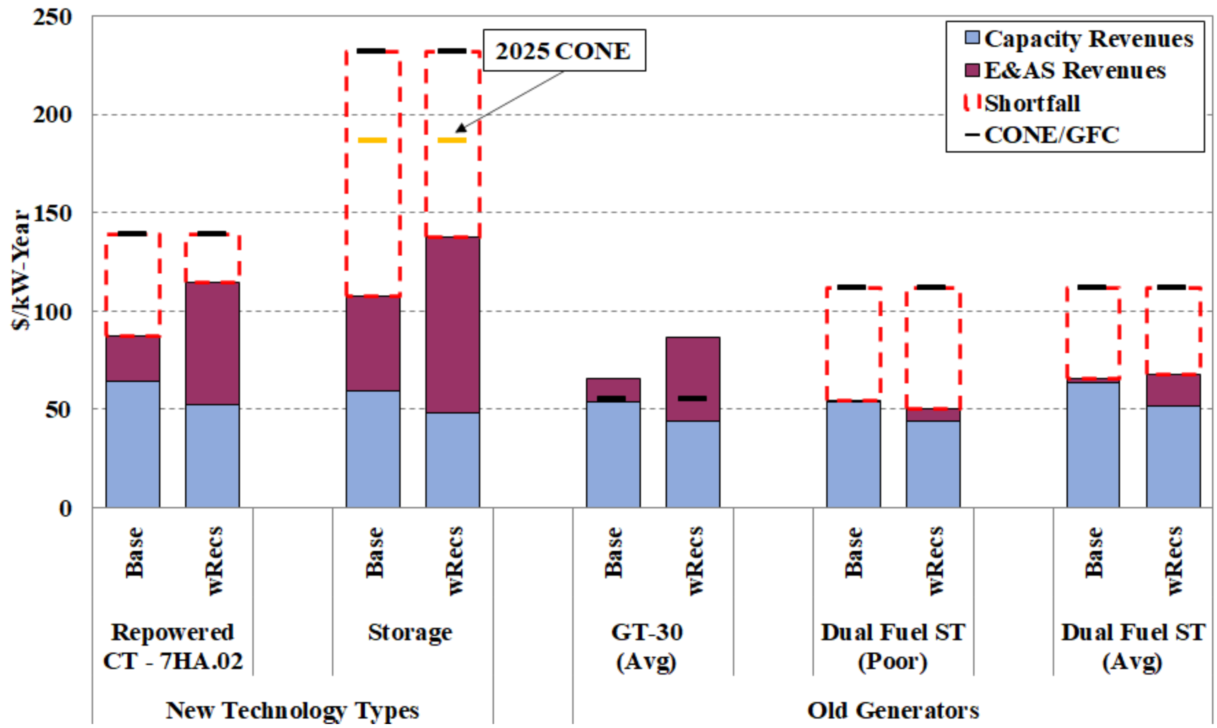


Figure A-130: Impact of Pricing Enhancements on Net Revenues – NYC Load Pocket #2
At Current Excess

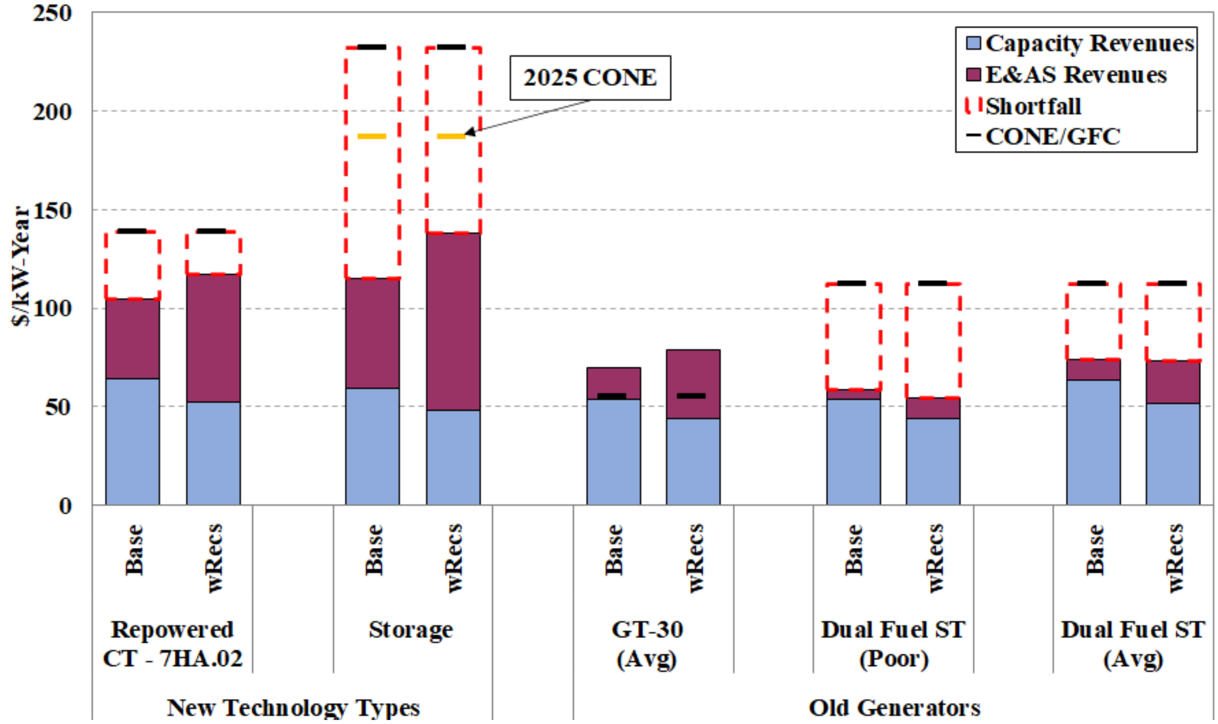


Figure A-131: Impact of Pricing Enhancements on Net Revenues – NYC 345 kV
At Current Excess

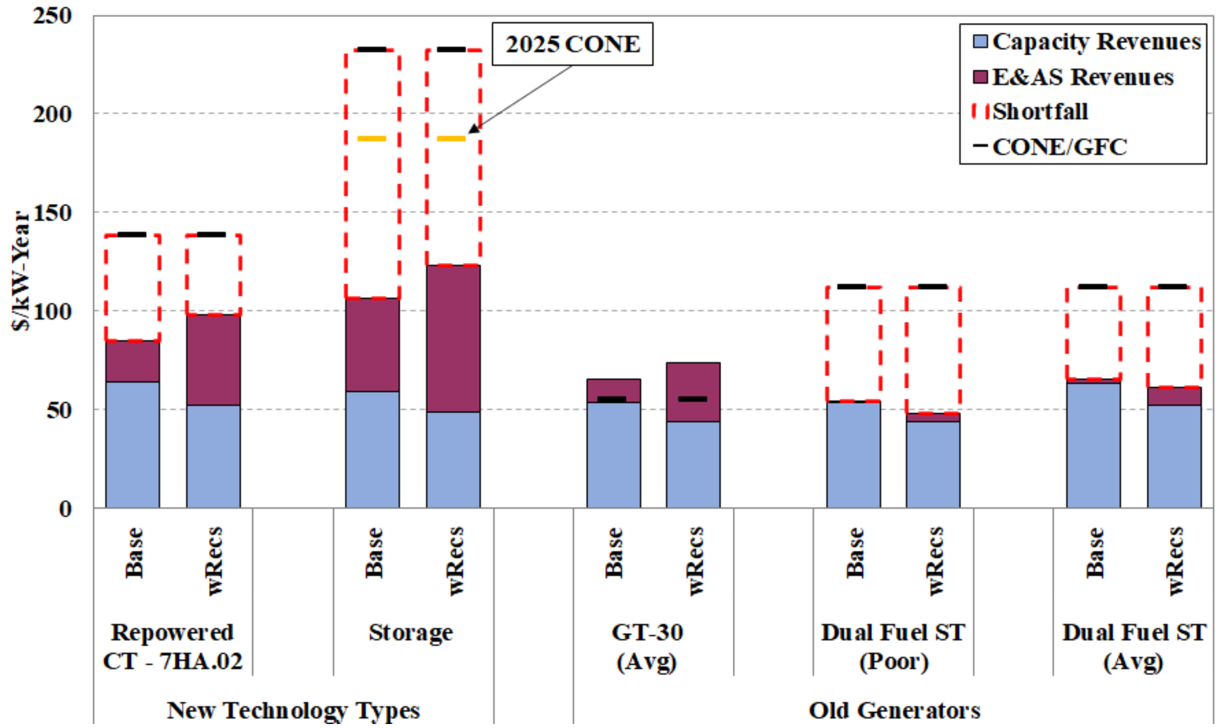


Figure A-132: Impacts of Pricing Enhancements on Consumer Costs in New York City

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-132 shows the estimated impact that the proposed enhancements would have had on New York City consumer costs using price data from the period 2019 to 2021. 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.[397] Capacity savings were valued at the level of excess assumed in the ICAP demand curves.

- *Uplift Savings* – We assumed savings of $19 million, equivalent to annual average BPCG payments made to generators that were committed for local N-1-1 needs in New York City.[398] 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.

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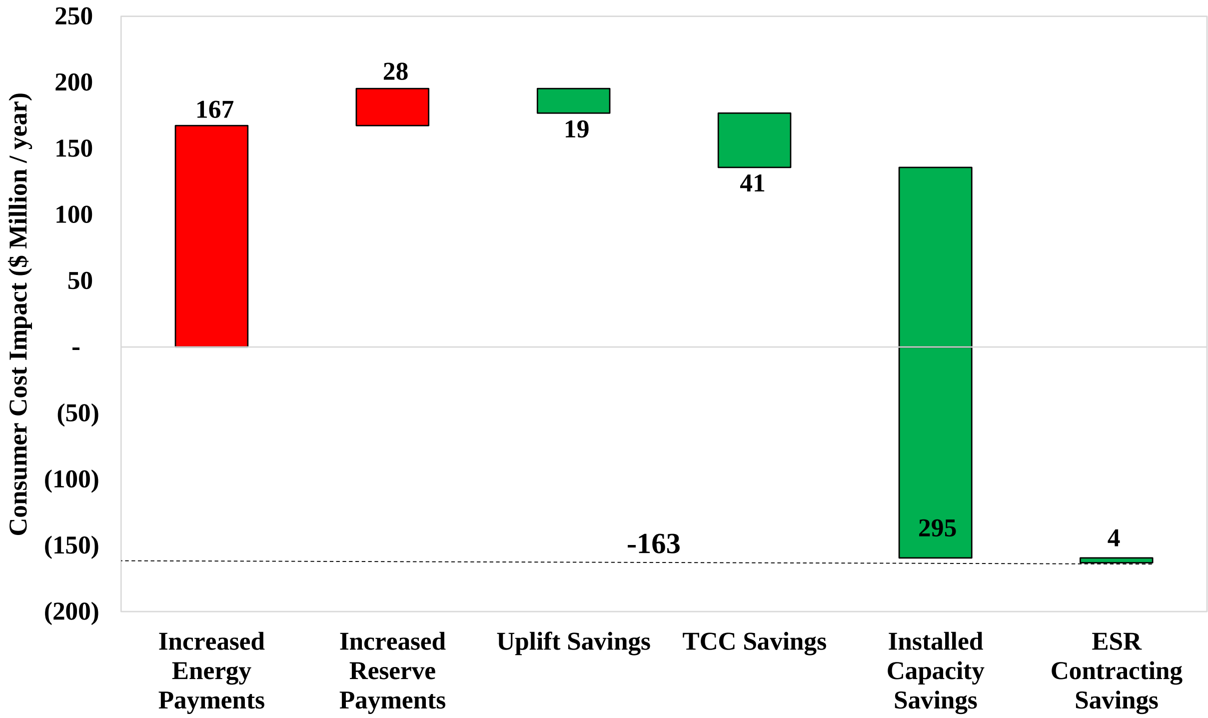
397 See Figure A-127. Note that the impact of the proposed pricing enhancements are assumed to be fully reflected in the net E&AS revenues of the demand curve unit during the period analyzed.

398 This value represents an average of day-ahead DAM Local BPCG uplift payments between 2019 and 2021. See Figure A-107. 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.

- *Energy Storage Contract Costs* – The NYSPSC established a mandate for Con Edison to contract with 300 MW of bulk energy storage resources in-service by 2025. 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-129 and Figure A-130), 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 ($16/kW-year in Load Pocket 1 and $9/kW-year in Load Pocket 2) as reduced contract payments paid by consumers.

Figure A-132: Impact of Price Enhancements on Consumer Costs in New York City

At Level of Excess Conditions



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.[399]

- 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.[400]

- 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.[401] 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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399 Resources participate in EDRP through Curtailment Service Providers ("CSPs"), which serve as the interface between the NYISO and resources.

400 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.

401 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 – This was scheduled for implementing its market design in Q4 2022, which should allow individual large consumers and aggregations of consumers to participate more directly in the market, and will better reflect duration limitations in their offers, payments, and obligations.

This section evaluates the performance of the existing programs in 2021 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

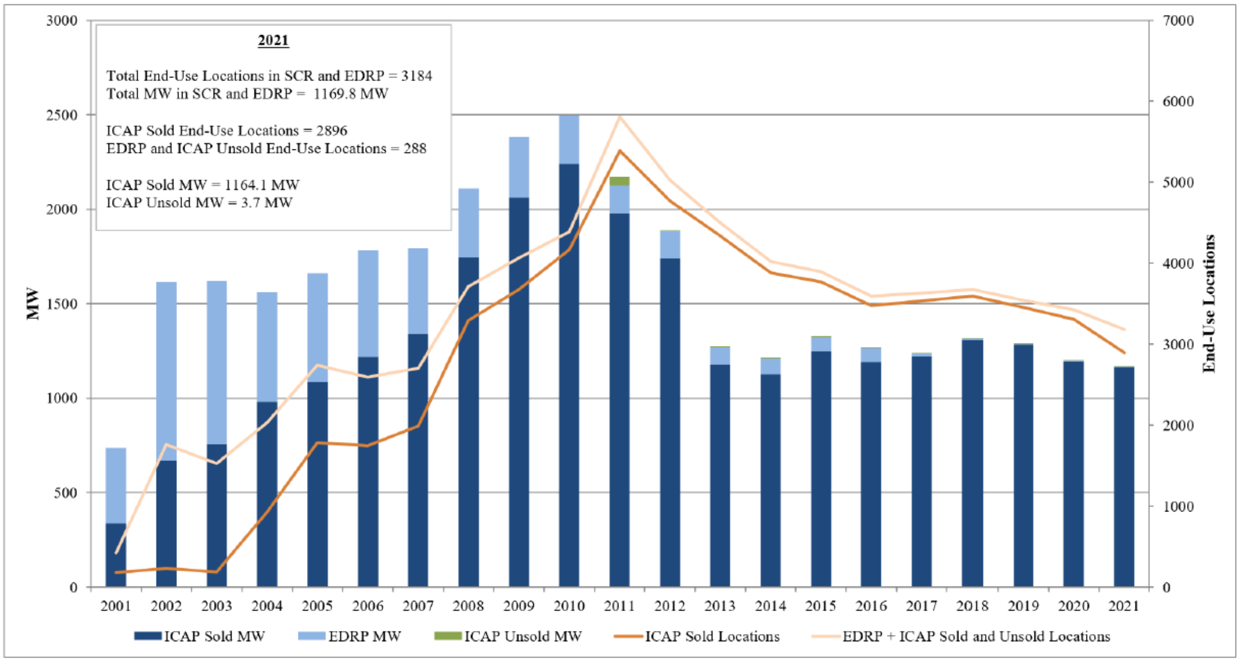
The EDRP, SCR, and TDRP programs enable NYISO to deploy reliability demand response resources when the NYISO and/or a TO forecast a reliability issue.

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 2021 as reported in the NYISO’s annual demand response report. The stacked bar chart plots enrolled ICAP 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.

- 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. The Expanding Capacity Eligibility market rules went effective on May 1, 2021. All SCR resources are required to have a 4-hour duration and their UCAP MWs reflect a Duration Adjustment Factor of 90% set currently for 4-hour resources.[402]

Figure A-133: Registration in NYISO Demand Response Reliability Programs [403]
2001 – 2021



B. Economic Demand Response Programs

The NYISO offers two economic demand response programs.[404] 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 the Monthly Net Benefit Offer Floor.[405] 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

402 See Section 4.1.1 of ICAP Manual for more details.

403 This figure is excerpted from *NYISO 2021 Annual Report on Demand Response Programs*, January 24, 2022, available at: www.nyiso.com/demand-response.

404 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.

405 Prior to November 2018, DADRP Resource offers were subject to a static floor price of $75/MWh. The Monthly Net Benefit Offer Floor prices are available at: www.nyiso.com/demand-response

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. DADRP enrollment has been static and no enrolled resources have submitted demand reduction offers 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.

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 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. Five DSASP resources in Upstate New York actively participated in the market in 2021 as providers of operating reserves. These five resources collectively can provide up to 175 MW of operating reserves.

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.

Table A-29 summarizes the reliability demand response events in 2021. The table lists for each event the program type (i.e., TDRP or SCR/EDRP), the start and end times, required zones, and obligated ICAP MWs. The table also indicates whether the scarcity pricing rule was triggered during the event. In 2021, the scarcity pricing rule was only triggered for a total of five five-minute intervals during the August 25th event.

Table A-29: Summary of Reliability Demand Response Activations
2021

DR Program	Event Date	Start Time	End Time	Event Zone	Obligated ICAP MW	Scaricity Pricing Triggered
TDRP	6/29/2021	14:00	19:00	J2	30.5	N/A
TDRP	6/30/2021	13:00	20:00	J2	30.5	N/A
SCR/EDRP	8/11/2021	13:00	19:00	K	36.8	No
SCR/EDRP	8/12/2021	13:00	20:00	K	36.8	No
SCR/EDRP	8/13/2021	13:00	20:00	K	36.8	No
SCR/EDRP	8/25/2021	13:00	20:00	K	36.8	Yes
SCR/EDRP	8/26/2021	13:00	20:00	K	36.8	No
SCR/EDRP	8/27/2021	13:00	20:00	K	36.8	No