2022 State of the Market Report For the New York ISO Markets

POTOMAC ECONOMICS

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EXECUTIVE SUMMARY

As the NYISO's Market Monitor Unit ("MMU"), our Core Functions include reporting on market outcomes, evaluating the competitiveness of the wholesale electricity markets, identifying market flaws, and recommending improvements to the market design. We also evaluate the market power mitigation rules, which are designed to limit anticompetitive conduct that would erode the benefits of the competitive markets. The 2022 State of the Market Report presents our assessment of the performance of the wholesale electricity markets administered by the NYISO in 2022. 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.

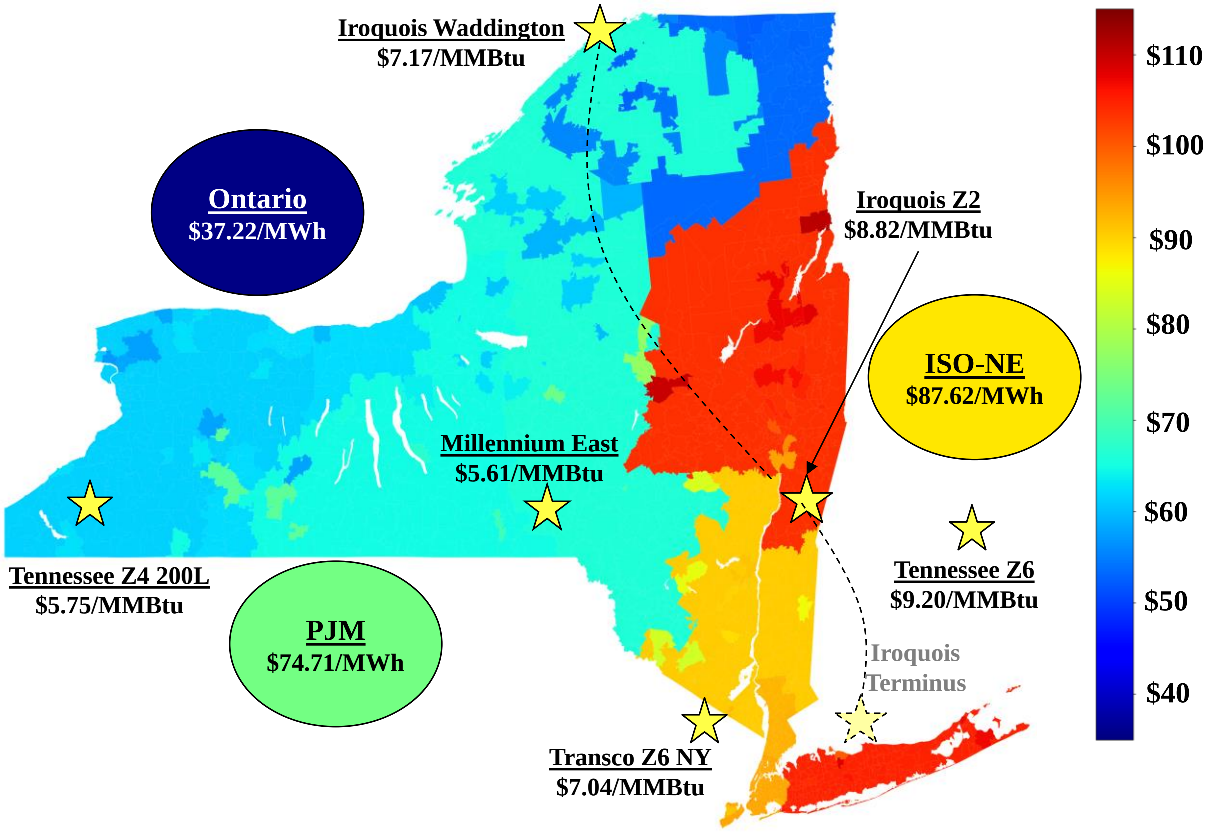
Market Highlights in 2022

The NYISO markets performed competitively in 2022 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

Natural gas prices and load levels are two key drivers of market outcomes. Average gas prices roughly doubled from last year in eastern New York and rose 70 percent in western areas. The largest increases occurred in winter months when large gas price differentials emerged because of congestion on pipelines crossing into eastern New York heading toward New England. Gas prices increased outside the winter months as rising LNG exports outpaced the growth in domestic production until the fall of 2022. (See Section II.C for details).

Real-Time Energy Prices, Natural Gas Prices, and Congestion in 2022



Energy Prices and Transmission Congestion

Real-time prices varied from an average of $50.46 per MWh in the North Zone to $108 per MWh in Long Island in 2022 because of transmission congestion and losses. (See Section II.A) Average energy prices rose substantially from 2021 to 2022, up 83 to 109 percent in Western New York and 73 to 126 percent in Eastern New York, primarily because of higher natural gas prices. The larger increases in eastern New York was largely attributable to: (a) more severe transmission bottlenecks across the Central-East interface due to lengthy transmission outages taken to facilitate the AC Public Policy Transmission Projects, and (b) larger gas price increases in eastern New York during the winter months.

Consequently, congestion revenues collected in the day-ahead market rose 82 percent from 2021, totaling $1 billion in 2022. (See Section VI.A) The following corridors accounted for most congestion in 2022:

- Central-East Interface – 60 percent
- External Interfaces – 9 percent
- Long Island – 9 percent

Capacity Market

Fluctuations in the statewide and local capacity requirements were the primary driver of capacity price variations. The statewide requirement decreased by over 1 GW, largely because of lower load forecasts. (See Section VII.A) This caused price in the "Rest of State" region (i.e., Zones A-F) and the Lower Hudson Valley (i.e., Zones GHI) to fall. Since NYC spot prices cleared on the systemwide curve for 10 of 12 months in Capability Year 2021/22, the reduced systemwide requirement for Capability Year 2022/23 also contributed to the price decrease for NYC. Lower load forecasts also caused the local requirement for NYC to fall by 137 MW.

The low prices in 2022 reflected high surplus capacity margins in New York City for the 2022/23 capability year (~15 percent), similar to the previous capability year. However, because the energy and reserve prices increased in 2022, the going forward cost ("GFC") of a well-maintained steam turbine was likely lower than its net revenues in New York City and in the Lower Hudson Valley. (See Section II.B) This may improve even further beginning as early as 2023 as capacity prices are expected to increase with the retirement (or move to non-Ozone Season operation) of older conventional generators that began in Winter 2022/23.

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. In recent years, investment has shifted towards clean energy resources in response to requirements under New York's state climate law for 70 percent renewable electricity by 2030 and 100 percent zero emissions electricity by 2040. NYISO market revenues play an important role, even for policy-driven investments, because they indicate which clean energy projects would have the highest wholesale market value. Ultimately, this reduces the cost of achieving policy goals.

In Section III.A we analyze incentives for investment in renewable and energy storage resources under recent market conditions. In general, we observe the following:

- Renewable generators rely heavily on both NYISO market revenues and state and federal subsidies, each of which make up roughly half of revenues that wind and solar projects would have earned in recent years.
- Investment in land-based wind has likely been profitable in recent years, consistent with the observed pattern among most new renewable generation projects. Permitting and land-use restrictions may limit how much land-based wind can be developed in practice.
- Market revenues and subsidies have generally not been adequate for utility-scale solar investment, but high prices in 2022 would justify solar investment at some locations.
- Battery storage has been uneconomic due to low capacity prices and high costs. In 2023, some projects may be economic due to the new 30 percent federal Investment Tax Credit.

In Section III.B, we review recent and upcoming investment in renewable resources and analyze how investment incentives may be affected by state policies. Since New York's Clean Energy Standard was launched in 2017, a relatively small share of the projects awarded REC contracts by New York State have entered service or begun construction. Most renewable projects have long-term contracts with the State for Index REC payments, which provide a hedge against changes in average energy and capacity prices. However, these contracts expose the developer to other NYISO market risks, including:

- The risk of prices being low at the project node due to local transmission constraints, and
- The risk of prices being low when the resource generates due to oversaturation of its technology in the market.

Exposure to these risks incentivizes developers to pursue technologies and locations more likely to provide value to the system. However, developers have difficulty managing the risk that future state-supported projects receiving higher subsidies will be encouraged to build, thereby suppressing wholesale market revenues. This risk reduces investors' willingness to build clean energy projects today. Policy initiatives that work through transparent uniform market signals reduce these risks and are likely to achieve their objectives at a lower overall cost.

In Section III.C, we evaluate whether NYISO's markets are designed to efficiently reward the wholesale services that energy storage provide, which help integrate renewables. We find:

- *NYISO's market will reward storage for reducing curtailment of renewables* – Studies of systems with high intermittent renewable penetration find that battery storage will benefit from increased price volatility. When a storage unit charges to reduce curtailments of renewables, it captures the environmental value associated with this because the renewable's REC value will be reflected in negative clearing prices. This creates strong incentives for storage developers to respond to renewable integration needs even if they do not receive state incentives. However, inefficient or excessive transmission investment will reduce these incentives and can increase risk for storage developers.
- *Revenues to energy storage will depend on penetration levels of solar and storage* – Under NYISO's new marginal capacity accreditation rules, capacity revenues of storage units will benefit from additional solar penetration, since they tend to shorten the length of critical reliability periods. However, capacity revenues of storage will fall as more storage is built since its benefits tend to diminish as more are added to the system. This suggests that the efficient level of storage investment depends on the level of renewable (especially solar) penetration. Hence, policies mandating procurement of storage that significantly exceeds efficient levels creates financial risks for other storage resources.
- *Ancillary services market reforms are needed to provide efficient investment incentives* – Ancillary services revenues are expected to play a large role in promoting storage investment. However, the current markets under-value flexible resources in several

ways, so we make recommendations to address these shortcomings. (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 reduce the need for costly transmission upgrades, and avoid the need for arbitrary contracting mandates that can substantially raise contract payments and lead to inefficient storage investment.

Capacity Market Performance

The capacity market is NYISO's primary mechanism for meeting resource adequacy requirements. It provides incentives to invest in and maintain generation needed for reliability without the need for centralized long-term procurements. This report identifies a number of areas for improvement (see Section VIII):

Need for better locational signals – there are currently four Capacity Zones with separate prices (New York City, Long Island, Lower Hudson Valley and Rest-of-State). Each year, local capacity requirements (LCRs) are determined using NYISO's "LCR Optimizer" method. Ideally, the capacity price in each zone should correspond to the marginal reliability benefit to the system of adding or maintaining capacity in that zone. However, the LCR Optimizer has design flaws that lead to inefficient prices across zones and contribute to excessive price volatility. Furthermore, the current layout of the capacity market with only four zones does not account for transmission limitations within those zones. As a result, resources at some locations are over- or under-compensated, leading to inefficient signals to invest in capacity at valuable locations and retire capacity at oversaturated ones. (See Section VIII.C)

To address this, we recommend that NYISO implement and dynamically update an expanded set of capacity zones that will reflect the known bulk transmission bottlenecks on the NYISO system (see Recommendation #2022-4). This will eliminate ongoing overpayment to resources in bottlenecked locations and improve the ability of the capacity market to accurately signal where capacity is needed. This recommendation would not rely on NYISO's existing capacity zone creation process, which is flawed and ineffective. This recommendation would also mitigate serious concerns that the current deliverability framework is an inefficient barrier to investment in new resources.

In the long term, we recommend that NYISO evaluate a framework in which the price at each location is determined based on its marginal reliability value (known as "C-LMP", #2013-1c) instead of the current zonal demand curves. This could result in sizeable reliability and economic benefits over the long term and simplify the administration of the capacity market.

Problems with resource accreditation – certain resource types are not accredited consistent with the benefit they provide to satisfy reliability requirements because of the following issues:

- NYISO's resource adequacy model does not accurately represent some resource types. NYISO recently adopted tariff changes to determine UCAP ratings for all resources based on the marginal improvement in reliability they provide, beginning in May 2024. This is a major improvement, but requires that the resource adequacy model accurately simulate resources' availability and output patterns. NYISO is evaluating changes in the modeling of some resource types including: gas-only units that cannot obtain fuel in winter, dual-fuel resources with limited oil inventories during prolonged cold weather, energy storage resources, and inflexible resources with long startup lead times. (see Section VIII.F)
- Some resource types provide limited value towards satisfying reliability requirements based on transmission security criteria. These include Special Case Resources (SCRs) and large resources whose size causes the transmission security planning contingency to increase. Transmission security requirements are increasingly likely to cause higher LCRs, especially in New York City. When this occurs, SCRs and large resources will be overcompensated and have inadequate incentives to take actions that would improve system reliability. In the upcoming 2023-24 capability year, we estimate that large resources and SCRs in New York City could be over-compensated by up to $52 million. (see Section VIII.G)
- NYISO currently overestimates the installed capacity of certain fossil fuel and nuclear generators. This includes resources with emergency capacity that is virtually never committed in practice, resources with ambient water and air humidity dependencies that are not captured in the DMNC testing process, and cogeneration units that face limitations associated with their steam host demand. As a result, we estimate that approximately 1,200 MW of ICAP received capacity payments but was functionally unavailable on the hottest days in Summer 2022. (see Section VIII.F)

To address these concerns, we recommend that NYISO improve the modeling of selected resource types in its resource adequacy model and develop procedures to more accurately determine the ICAP of units with functionally unavailable capacity (#2021-4). We also recommend that NYISO compensate capacity suppliers based on their contribution to transmission security when LCRs are set by transmission security needs (#2022-1). These recommendations will improve incentives to invest in reliable capacity and reduce overpayments to over-accredited resources.

Lack of a seasonal market – although the capacity market has separate Summer and Winter capability periods, both seasons use the same capacity requirements and ICAP demand curves. As a result, seasonal prices are determined by the amount of ICAP available in each season, which bears little relation to resource adequacy risk. Winter reliability risk is growing in importance, so it is important for seasonal capacity prices to recognize the value of resources that have different summer and winter availability. NYISO has proposed changes to its capacity market demand curves that will improve seasonal pricing if implemented in conjunction with resource adequacy model enhancements. However, it continues to rely on a single capacity requirement that is applied year-round (See Section VIII.I). We recommend transitioning to a seasonal capacity market in which requirements and demand curves are determined for each season (see Recommendation #2022-2).

Deliverability Testing and Transmission Planning Processes

An influx of proposed new renewable and storage projects in NYISO's interconnection queue in recent years has led to a heightened focus on transmission planning and interconnection issues. It is efficient to allocate the costs of upgrades needed for a new project to reliably interconnect to the grid and be deliverable to load to that project, so that developers are not incentivized to disregard transmission limitations. At the same time, new projects should not bear a disproportionate share of the cost of upgrades that benefit the network as a whole, since this will deter efficient new investment. In Section IV.A, we evaluate the deliverability testing process.

Concerns with the Deliverability Testing Process

The process for obtaining rights to sell capacity ("CRIS rights") can be a major obstacle for investment in new generation. The recently completed Class Year 2021 study initially allocated $1.5 billion in System Deliverability Upgrade (SDU) costs to new projects seeking to sell capacity. For the 4 GW of projects that were assigned SDUs, these costs range from $468 to $2,557 per kilowatt of UCAP the resources would be able to sell in the capacity market. On a levelized basis, these SDU costs alone are equivalent to 50 to 293 percent of the net cost of new entry of a new peaking plant in the same area. Unsurprisingly, three quarters of the affected projects refused to pay these costs and either withdrew from the Class Year or accepted a reduced quantity of CRIS rights.

In Section IV.A, we highlight ways in which NYISO's deliverability framework is misaligned with its primary purpose of enabling new projects to support resource adequacy and unreasonably inhibits new investment. We find that the deliverability framework:

- Utilizes a deterministic test that often does not represent a realistic or likely dispatch of the system during conditions when reliability is threatened. Hence, the current test is likely to produce inaccurate or excessive indications of needed upgrades. This problem is exacerbated by performing the test in relatively large capacity zones with many potential intrazonal constraints.
- Is particularly likely to identify and allocate excessively large SDUs to renewable and storage project developers as their penetration grows. This is because NYISO's

deliverability test methodology does not accurately model the performance of these resources during tight hours when capacity is most needed;

- Assigns permanent CRIS rights that may not accurately reflect a resource's deliverability over time, because the deliverability test relies on uncertain assumptions about factors that will change in the future. This may either: (a) require project developers to pay for larger upgrades than they will need over the project's life or (b) allow projects to obtain CRIS rights when they will not be fully deliverable; and
- Favors existing resources over new resources because it requires developers of new resources to pay for costly network upgrades but imposes no costs on existing resources that contribute to the same bottlenecks. This imposes a barrier to new resources that effectively prevents them from competing with incumbent resources in export-constrained areas such as Staten Island.

To address these issues, we recommend implementing a process to define a comprehensive set of granular locations in the capacity market in the short term (#2022-4). This would effectively shrink the size of the capacity zone in which new interconnecting resources would have to be deliverable and allow the capacity clearing price to drop in export-constrained areas. We also encourage NYISO to reform the deliverability testing rules to more accurately identify intrazonal deliverability issues. Together, these changes would substantially reduce the number and size of system upgrades developers would be obligated to fund. However, project developers may still wish to pay for network upgrades if transmission bottlenecks would cause their locational capacity price to be low. Hence, we also recommend financial capacity transfer rights (FCTRs), which could be defined so that market participants who pay for upgrades retain the economic value of those upgrades in the capacity market (#2012-1c).

Improvements to Transmission Planning Process

In Section IV.B, we provide an overview of NYISO's centralized transmission planning process and suggest improvements so that more efficient projects can be selected. In recent years, large-scale transmission planning takes place primarily through the Public Policy Transmission Planning Process (PPTPP) and is oriented towards facilitating state renewable energy targets. Even when transmission projects are planned to meet policy goals, consideration of their NYISO market impacts is important because (1) market prices help quantify which policy projects provide the best value to ratepayers and (2) inefficient transmission projects risk crowding out competing market-based investments (including transmission and non-transmission resources) that could advance the same policy goals at lower cost.

NYISO has recently improved its planning studies by implementing capacity expansion modeling tools, but the need to account for future growth of policy-sponsored resources increases uncertainty and has led to new challenges. Hence, improvements are needed to accurately forecast future transmission needs and evaluate potential solutions. We suggest the following (Recommendation #2022-3):

- Update the methodology of NYISO's planning study (the "Outlook") to better account for market incentives of renewable and storage resources;
- Evaluate economic and public policy projects using a project case that considers changes to the resource mix resulting from the evaluated Project's inclusion; and
- Estimate transmission project benefits based on their NYISO market value.

Energy and Ancillary Services Market Performance

We evaluate the performance of the market in scheduling resources efficiently and setting real-time prices, 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.

Market Performance under Reserve Shortage Conditions

Shortage pricing will be perhaps the most essential element of the real-time market as New York transitions to a more intermittent generating fleet. 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 will likely 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. We find that the NYISO's shortage pricing is lacking and identify two enhancements that would improve scheduling efficiency and real-time pricing during shortage conditions:

- 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)
- 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

demand curve values are 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. Therefore, we recommend NYISO modify its reserve demand curves to be consistent with the *Value Of Lost Load* ("VOLL") and the likelihood that various operating reserve shortage levels could result in load shedding. (See Section VI.A and Recommendation #2017-2)

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 $5000 to $8000 per MWh during 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 to schedule imports and exports efficiently and for resources to be responsive to emergency conditions will become increasingly important as New York's reliance on intermittent resources increases.

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. The NYISO market experienced such localized shortages in roughly 14 percent of intervals in 2022. 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 plans to implement *Constraint Specific Transmission Shortage Pricing* in the fourth quarter of 2023, which is expected to: (a) increase the GTDC more gradually than the current GTDC; (b) have a MW-range in the GTDC that corresponds to the CRM of the constraint; and (c) extend the GTDC to internal facilities that are currently assigned a zero value CRM. This will significantly improve the current GTDC. (See Section VI.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 in 5 minutes even though they actually cannot. This disconnect leads to large differences between modeled flows (that assume output from the offline units) and actual flows (that recognize 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 VI.A and Recommendation #2020-2)

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 2022, this allowed additional flows of:

- 24 to 44 percent (of the facility seasonal LTE rating) on the 345 kV transmission lines from upstate New York into New York City; and
- 7 to 29 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. This can lead to inefficient scheduling and pricing in the real-time market, as well as 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 two years, efficient market incentives are needed to attract new 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 VI.D 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 over 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 dispatch model.

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 VI.C and Recommendation #2020-1)

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 2022, 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 – $2.4 million in 2022. 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 IX.C and Recommendation #2015-9)

The performance of the CTS process and other scheduling functions of the RTC model were increasingly affected by external transaction curtailments in 2022. After RTC schedules external transactions, they are sometimes curtailed by NYISO operators or another control area for reliability or transmission security. In 2022, the frequency of large (100+ MW) curtailments increased to 13 percent of hours from 7 percent in the previous year. Curtailments often occur after the time of decisions about whether to start-up or shut-down peaking units, so curtailments often cause unforeseen shortages. This was highlighted during Winter Storm Eliot:

- On December 23 and 24, there were three periods of deep statewide reserve shortages in which neighboring control area operators curtailed transactions scheduled to NYISO. Initially, the curtailments occurred close to real-time, leading RTC to make inefficient commitment decisions related to fast-start units.
- In response, NYISO disabled the CTS process in the morning on December 24 and reverted to hourly transaction scheduling, which greatly reduced the number of inefficient commitment decisions related to fast-start units during the last reserve shortage event.

When a neighboring system is in emergency conditions, it may be appropriate to schedule additional reserves to the extent that the NYISO relies on imports that have a higher likelihood of being curtailed. (see Section II.G)

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 throughout the year. (See Section IX.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 help 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 2022, the operation of these lines (in accordance with the wheeling agreements) ***increased*** (a) production costs by an estimated $22 million; (b) CO_2 emissions by an estimated 445 thousand tons; and (c) NOx emissions by an estimated 607 tons.

The ConEd-LIPA wheeling agreement continues to use the 901 and 903 lines in a manner that raises production costs inefficiently. As offshore wind and other intermittent generation is added to New York City and Long Island, the operational flexibility of these lines would become increasingly useful if they could be utilized to avoid curtailing renewable generation. This 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 VI.E and Recommendation #2012-8.)

Out-of-Market Actions

Guarantee payments to generators rose by 74 percent from 2021 to $94 million in 2022. The increase was driven primarily by higher natural gas prices that increased the commitment cost of gas-fired resources. Higher supplemental commitments and more frequent OOM actions were also important contributors. (See Section VI.F)

New York City

OOM commitments to satisfy the N-1-1-0 requirements in the load pockets continued to account for most (87 percent) of all reliability commitments in 2022. Over $36 million of guarantee payment uplift accrued on units that were committed for this purpose. 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 for flexible resources in these areas. (See Section VI.F and Recommendation #2017-1)

NYISO plans to model New York City load pockets as a follow-up to its *Dynamic Reserves* project. 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. 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 will lead to large deviations of net load from the forecast over multiple hours. Procuring additional reserves from resources with longer response times (e.g., combined cycle units) 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 #2021-1)

Long Island

NYISO has integrated five 69 kV constraints into its day-ahead and real-time markets since April 2021. This integration has resulted in a significant decrease in the number of OOM dispatches, with a reduction of almost 50 percent in 2021 and 2022 compared to the levels observed in 2020. This has led to more efficient scheduling and pricing and reduced BPCG uplift in this category. However, OOM commitments for Transient Voltage Recovery (“TVR”) requirements on the East End of Long Island were still frequent, leading to very poor price signals in that area. To provide more efficient incentives for scheduling and new investment, we recommend NYISO model East End TVR needs (using surrogate constraints) in the market software. (See Section VII.B and #2021-3)

We found that the current Long Island reserve requirement was sometimes inadequate to satisfy N-1-1-0 criteria, and operators had to rely on OOM commitments on 27 days in 2022. Modeling these reserve requirements in Long Island would improve efficiency and encourage new resources with flexible characteristics to locate where they are most valuable. Hence, we recommend that NYISO implement reserve requirements for Long Island that are adequate to maintain reliability rather than rely on OOM actions. (See Section V.F and #2021-2)

Upstate New York

OOM commitments in upstate regions rose in 2022. The increase reflected OOM commitments that were made to satisfy the N-1-1 criteria: (a) in the North Country load pockets on 67 days; and (b) in the Capital Zone 115 kV network on 35 days. Modeling reserve requirements in these local load pockets would improve market efficiency and establish proper market signals for future investments, similar to our recommendation for Long Island. Overall, improving the market efficiency and reliability of the power grid in New York State requires careful consideration of local load pockets and the specific reserve requirements needed to ensure adequate reliability in those areas.

Overview of Recommendations

Our analysis in this report indicates that the NYISO electricity markets performed well in 2022, 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 2021 SOM Report, but Recommendations #2022-1 to #2022-4 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 XII. In total, we have nineteen outstanding recommendations that are discussed in that section. In addition, the NYISO moved forward with market reforms that would address one recommendation from our previous State of the Market report in 2021.

High Priority Recommendations in the 2022 SOM Report

Number	Section	Recommendation	Current Effort
Energy Market Enhancements - Pricing and Performance Incentives			
2017-1	VI.F	Model local reserve requirements in New York City load pockets.	*Dynamic Reserves* project underway; complete market design targeted 2023.[1]
2015-16	VI.A	Dynamically adjust operating reserve requirements to account for factors that change the amount of reserves that must be held on internal resources.	
2017-2	VI.A	Modify operating reserve demand curves to improve shortage pricing and ensure NYISO reliability.	
Capacity Market – Design Enhancements			
2022-4	VIII.D, IV.A	Implement a dynamic process for defining granular locations in the capacity market.	
2021-4	VIII.F	Improve capacity modeling and accreditation for specific types of resources.	*Modeling Improvements for Capacity Accreditation* underway.

1 The 2022 Master Plan includes a 2025-2027 project called *More Granular Operating Reserves* to address Recommendation 2017-1 following the implementation of the *Dynamic Reserves* project in 2026.

I. INTRODUCTION

This report assesses the efficiency and competitiveness of New York's wholesale electricity markets in 2022.[2] The NYISO operates competitive wholesale markets to satisfy the electricity needs of New York. These markets include:

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

The energy and ancillary services markets establish prices that reflect the value of energy at each location on the network. They deliver significant benefits by coordinating the commitment and dispatch of generation to ensure that resources are started and dispatched each day to reliably meet the system's demands at the lowest cost. The coordination provided by the markets is essential because of the physical characteristics of electricity. This coordination affects not only the prices and production costs of electricity, but also the reliability with which it is delivered.

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

- Simultaneous optimization of energy, operating reserves, and regulation, which efficiently allocates resources to provide these products;
- Locational requirements in its operating reserve and capacity markets, which play a crucial role in signaling the need for resources in transmission-constrained areas;
- Capacity demand curves that reflect the value of incremental capacity to the system and provide for increased stability in market signals;
- Ancillary services demand curves, which contribute to efficient prices during shortages when resources are insufficient to satisfy all of needs of the system;
- A real-time commitment system (i.e., RTC) that commits quick-start units (that can start within 10 or 30 minutes) and schedules external transactions. RTC runs every 15 minutes, optimizing over a two-and-a-half hour period.

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

- A market scheduling system (i.e., Coordinated Transaction Scheduling) to coordinate an economic evaluation of interchange transactions between markets 15 to 30 minutes ahead of when the power flows in real-time.
- A mechanism that allows inflexible gas turbines and demand-response resources to set energy prices when they are needed, which is essential for ensuring that price signals are efficient during peak demand conditions.
- A real-time dispatch system (i.e., RTD) that runs every five minutes and optimizes over a one-hour period, allowing the market to anticipate the upcoming needs and move resources to efficiently satisfy the needs.

These market designs provide substantial benefits to the region by:

- Ensuring that the lowest-cost supplies are used to meet demand in the short-term; and
- Establishing transparent price signals that facilitate efficient forward contracting and govern generation and transmission investment and retirement decisions in the long-term. Relying on private investment shifts the risks and costs of poor decisions from New York's consumers to the investors.

As federal and state policy-makers promote public policy objectives such as environmental quality through investments in electricity generation and transmission,[3] the markets should adapt as the generation fleet shifts from being primarily fossil fuel-based, controllable, and centralized to having higher levels of intermittent renewables and distributed generation. Although large-scale changes in the resource mix currently result primarily from public policies to reduce pollution and promote cleaner generation, the NYISO markets should still provide:

- Useful information regarding the value of electricity and cost of production throughout the State, enabling clean energy procurements to select more efficient proposals and transmission planning processes to identify needs appropriately and select the most efficient solutions; and
- Critical incentives not only for placing new resources where they are likely to be most economical and deliverable to consumers but also for keeping conventional resources that help integrate clean energy resources while maintain system reliability.

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

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

II. OVERVIEW OF MARKET TRENDS AND HIGHLIGHTS

This section discusses significant market trends and highlights in 2022. 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.

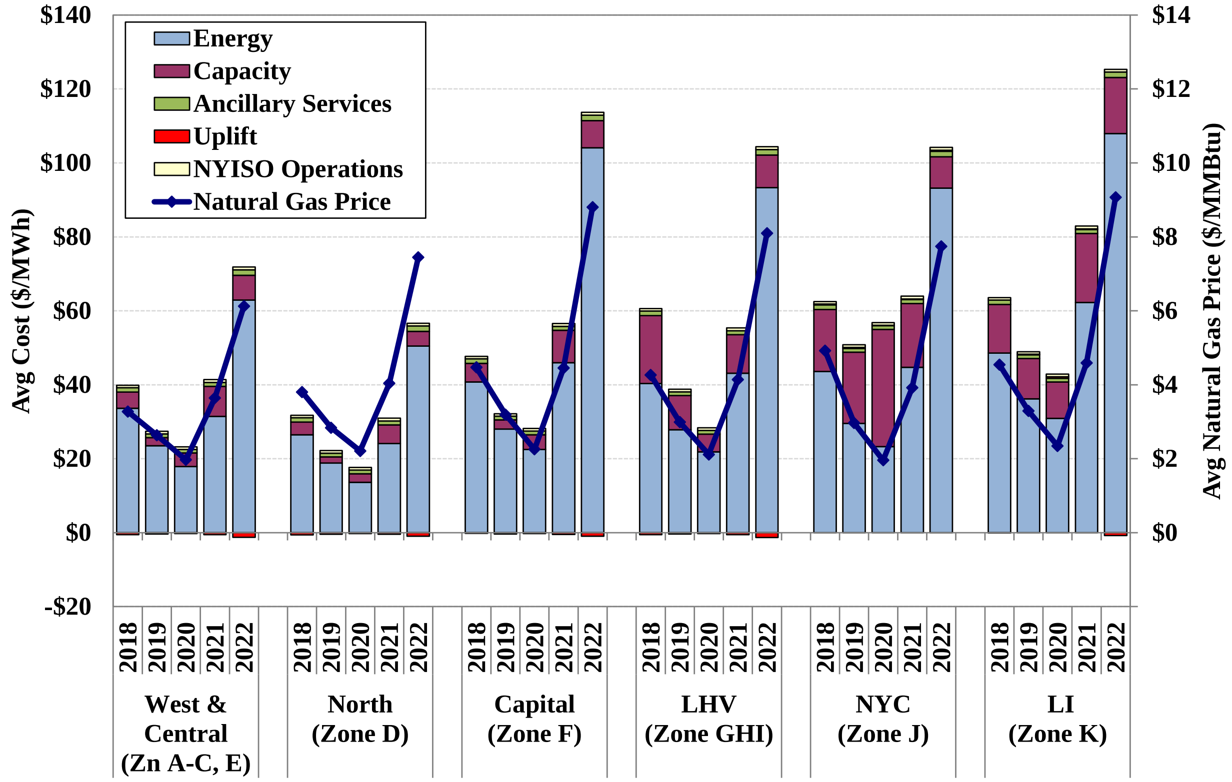
A. Wholesale Market Costs

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 major components of this metric include:

- The Energy Component is the load-weighted average real-time energy price.
- The capacity component is based on monthly spot auction clearing prices and capacity procured in each area, allocated over the energy consumption in that area.

All other components are the costs divided by the real-time load in the area.[4]

Figure 1: Average All-In Price by Region
2018 - 2022



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

In 2022, average all-in prices rose to the highest levels observed in more than a decade, ranging from $58 per MWh in the North Zone to nearly $127 per MWh in Long Island. All-in prices rose 50 to 100 percent from 2021 mainly because of the following factors:

- Natural gas prices doubled from 2021 levels because of several factors, including increased LNG exports and domestic demand. Cold weather across much of January and February, along with exceptionally volatile periods in December, further contributed to higher annual average gas prices. Fuel prices are evaluated further in Subsection C.
- Cold weather experienced around the 2022 Christmas Holiday led to significant real-time market price volatility. Significant transaction curtailments from PJM coupled with high natural gas prices and higher-than-expected quantities of generator outages and derates resulted in frequent shortage pricing hours, especially on December 23 and 24. The December cold weather event is evaluated further in Subsection G.
- Transmission congestion became more severe, especially from Central New York to East New York and from upstate into Long Island, primarily because of lengthy forced transmission outages and planned outages related to ongoing efforts to upgrade segments of the transmission system. More is written on congestion patterns in Section VII.

However, capacity prices fell moderately from last year, partially offsetting the inflationary effects of higher energy costs on all-in prices. Capacity costs fell primarily due to changes in the Installed Reserve Margin ("IRM") for the system and Locational Capacity Requirements ("LCR") for the local capacity zones. Capacity costs in 2022 fell from levels experienced in 2021 in all regions:

- Decreased 16 to 21 percent in Rest of State regions (i.e. Zones A-F),
- Decreased 15 percent in the Lower Hudson Valley (i.e., Zones G, H, and I),
- Decreased 51 percent in New York City, and
- Decreased 19 percent in Long Island.

As mentioned above, these changes were caused primarily by changes in the IRM and LCRs. IRM values in the G-J Locality and in NYC have remained low since the 2021 Summer causing the NYCA requirement to bind before the local requirements in many months. We discuss the reasons for this in Section VIII of this report.

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 conventional technologies in New York.

Figure 2 shows the net revenues and the estimated going-forward costs ("GFCs") for several existing technology types from 2020 to 2022. 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 evaluate the financial returns of dual-fuel capability, net revenues from oil-fired operation are shown separately.

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.[5] 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. Hence, the figure also shows a "Short-Term GFC" for New York City steam units, which excludes major maintenance and other capital expenditures. Even the "Short-Term GFC" includes some plant-level costs that would be difficult to avoid by retiring a single unit.[6,7]

For gas turbines in New York City, we show revenues for resources that operate only outside of the "ozone season" (May through September). A large amount of gas turbine capacity in NYC has indicated either that it will retire or will cease operating in the ozone season by 2025 to comply with NYSDEC "Peaker Rule" NOx emissions regulations.[8]

Revenues of existing fossil units during this period were mainly driven by fluctuations in capacity prices. However, E&AS net revenues increased in 2022 for two main reasons. First, transmission outages related to ongoing the construction of the AC Public Policy Transmission Projects led to higher margins east of the Central East interface. Second, high gas prices in winter led to higher margins and increased revenues for resources with oil-fired capacity on days with very high gas prices, including dual fuel resources.

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 usually 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.

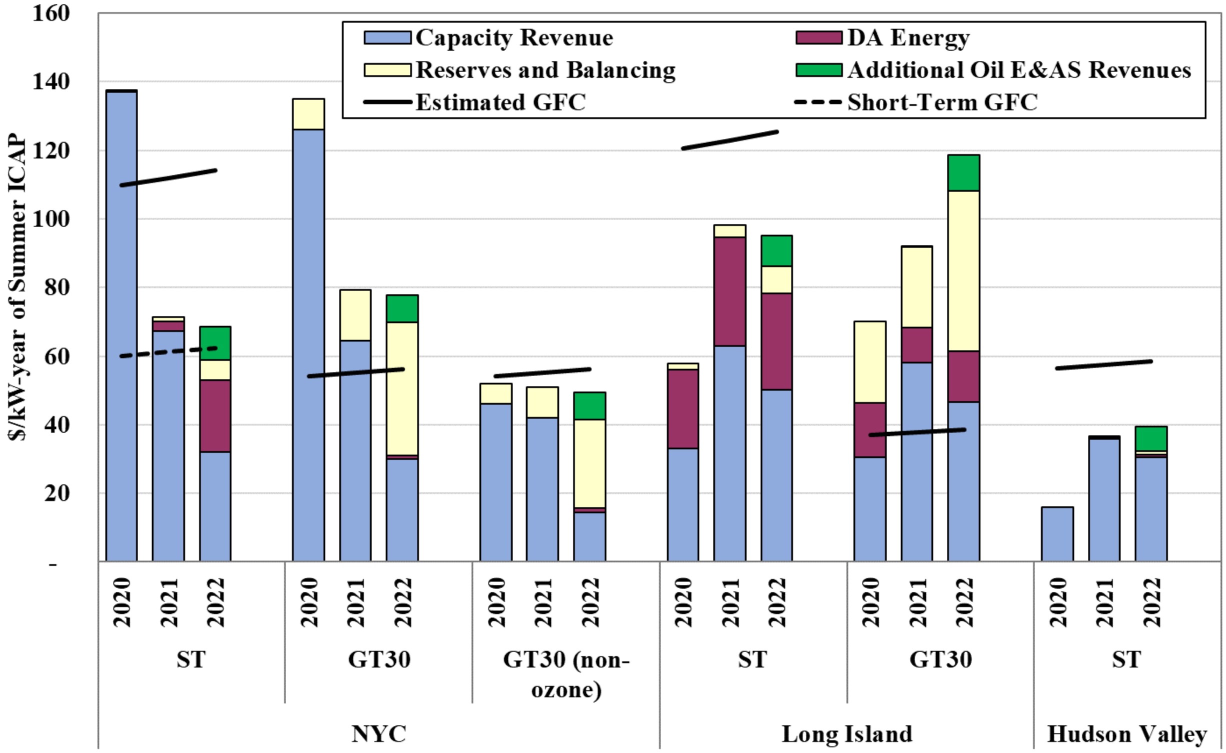
5 The "Estimated GFC" for existing gas generators is based on Analysis Group's report "NYISO Capacity Market: Evaluation of Options".

6 The "Short-Term GFC" includes estimated fixed O&M costs, property tax and administrative costs with all major maintenance and capital expenses excluded.

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

8 See Table IV-6 of the 2022 NYISO Gold Book.

Figure 2: Net Revenues and Going-Forward Costs of Existing Units
2020 – 2022



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. In Long Island, steam turbine generators are compensated through long-term contracts, 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.

Gas turbine units in New York City and Long Island have historically received net revenues above the estimated GFC because of high reserve market revenues and relatively low GFCs. 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 half of their net revenues from reserves and balancing operations in New York City and Long Island in 2022. Less flexible steam units, on the other hand, gain limited 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. As Figure 2 shows, gas turbine units in New York City would have earned slightly less than their going-forward costs if operating only outside of the ozone season months. Lack of summer revenues may make it difficult for these resources to remain in service over time, making it urgent for the NYISO markets to adequately value winter reliability.

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 cleaner as envisioned by policy-makers while maintaining reliability at lowest possible cost. Hence, we have recommended market enhancements in Section XII that would help reward resources more appropriately for these characteristics to help steer investment in favor of resources that provide the greatest value.

C. Fuel Prices

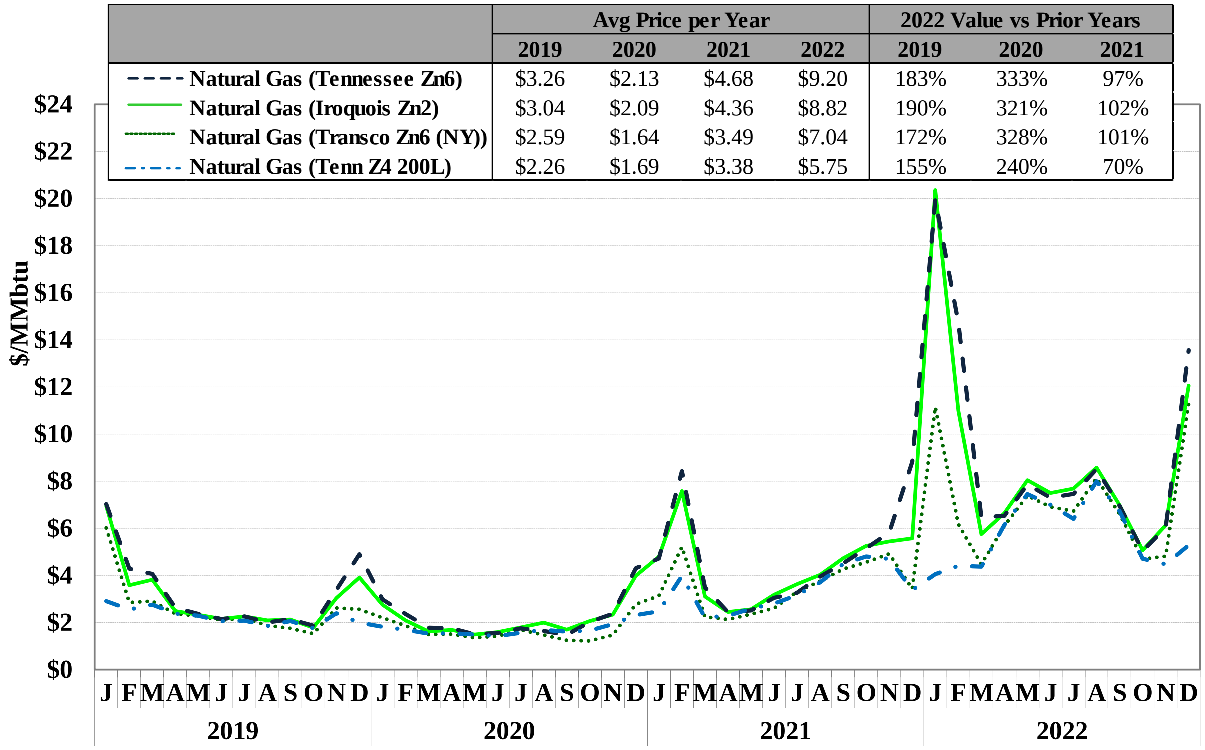
In recent years, fossil fuel price fluctuations have been the primary driver of changes in wholesale energy prices. Figure 3 displays monthly natural gas prices from 2019 to 2022 for several relevant indexes to the system. The inset table shows the average annual gas prices for those indexes as well as how the 2022 annual value compares to each of the preceding 3 years (i.e., 2019-2021).[9]

Average natural gas prices have risen rapidly over the past two years, reaching a new decade high value in 2022. Year-over-year, gas prices rose by roughly 100 percent for all major pipeline indices applicable to Eastern NY. Upstate gas indices also rose sharply, with increases annually ranging from 70 percent to 98 percent. A number of factors contributed to the large annual increase in gas prices. From a macro perspective, a combination of rising LNG exports during the first 8 months of the year and increased domestic gas demand drove prices up across the country. New York regional gas prices experienced elevated winter price volatility during January, February, and December due to cold weather conditions and associated pipeline constraints. This latter driver was an especially large contributor to higher Eastern NY electric prices during 2022.

9 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.

Figure 3: Average Fuel Prices and Real-Time Energy Prices
2019 – 2022

	Avg Price per Year				2022 Value vs Prior Years		
	2019	2020	2021	2022	2019	2020	2021
Natural Gas (Tennessee Zn6)	$3.26	$2.13	$4.68	$9.20	183%	333%	97%
Natural Gas (Iroquois Zn2)	$3.04	$2.09	$4.36	$8.82	190%	321%	102%
Natural Gas (Transco Zn6 (NY))	$2.59	$1.64	$3.49	$7.04	172%	328%	101%
Natural Gas (Tenn Z4 200L)	$2.26	$1.69	$3.38	$5.75	155%	240%	70%



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.

Table 1 shows the following load statistics for the New York Control Area ("NYCA") since 2013: (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.

The average load across the system was similar to 2021 levels. The Summer Peak (as Reported) fell by roughly 400 MW in 2022, but much of this decrease annually was due to higher levels of utility demand response activation. Despite the recovering conditions following the demand shock that the COVID Pandemic introduced in 2020, average load levels in 2022 remained low, from a historical perspective, averaging just 17.4 GW over the year. This continued a general downward trend in load that has been observed since 2013.

Table 1: Peak and Average Load Levels for NYCA
2013 – 2022

Year	Load (GW)			
	Summer Peak (as Reported)	Summer Peak (Reconstituted)	Winter Peak	Annual Average
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
2022	30.5	31.2	23.2	17.4

E. Generation by Fuel Type

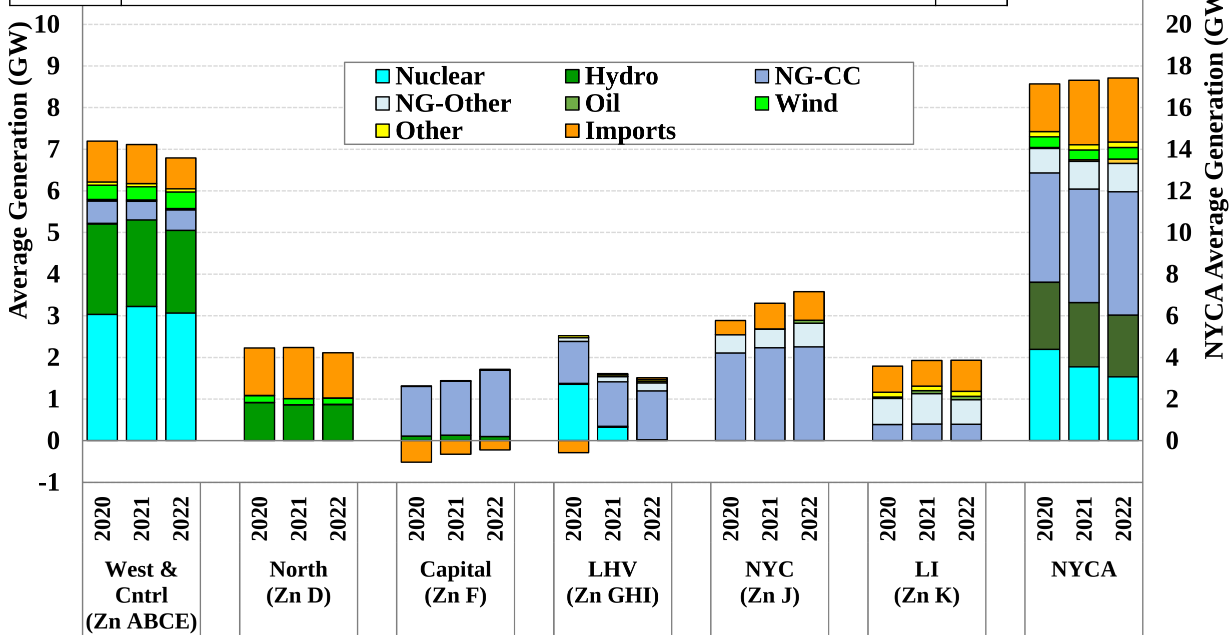
Variations in fossil fuel prices, retirements and mothballing of old generators, and the additions of new gas-fired generation in recent years have led to concomitant changes in the mix of fuels used to generate electricity in New York. Figure 4 displays annual generation by resource type from 2020 to 2022 (including net imports). Net import levels are assigned 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 are split 55 percent to the Capital Zone and 45 percent to the Lower Hudson Valley; and I the Scheduled 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 2020 to 2022, and this share has risen from 43 percent in 2020 to 51 percent in 2022. 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.

Before 2021, over half of internal generation came from 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 and 42 percent in 2022. Following the Indian Point retirement, there has been an increase in net imports and gas-fired generation.

Figure 4: Generation by Type and Net Imports to New York
20–0 - 2022

Year	Internal Generation by Fuel Type in NYCA (GW)								
	Nuclear	Hydro	NG-CC	NG-Other	Oil	Wind	Other	Imports	Total
2020	4.39	3.22	5.24	1.18	0.04	0.51	0.27	2.29	17.14
2021	3.55	3.09	5.45	1.33	0.08	0.47	0.25	3.10	17.31
2022	3.06	2.97	5.92	1.37	0.21	0.55	0.26	3.08	17.42



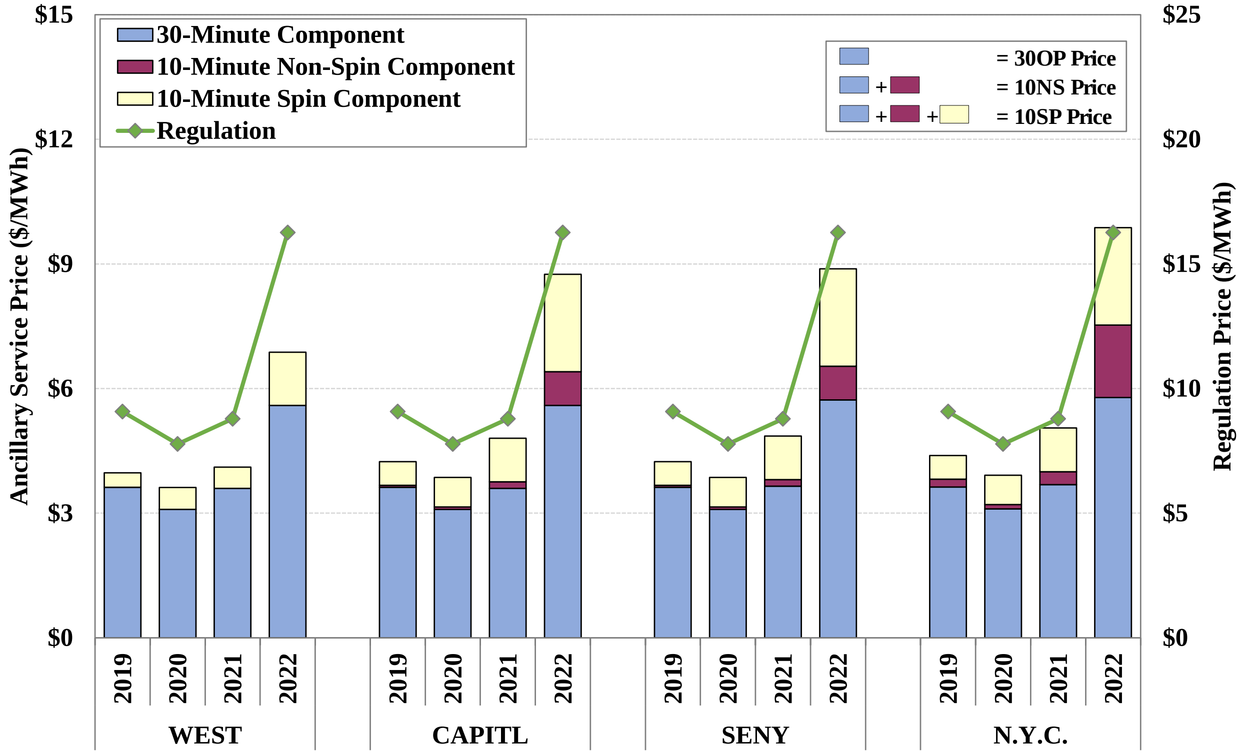
Tight winter conditions, especially in the first two and the last month of the year, led to a 260 percent increase in oil-fired generation in 2022 from prior year levels. When gas supply is scarce, the system is heavily reliant on the availability and performance of dual fuel capable or oil-fired generators, mostly in Southeast NY. The cold weather events in December 2022 highlighted that when dual fuel units switch from gas to oil, the frequency of forced outages and derates tends to increase. The performance and recommendations related to these outages is discussed further in Section G.

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.[10]

Figure 5: Average Day-Ahead Ancillary Services Prices
2019 - 2022



Average day-ahead prices for all reserve products rose in 2022, 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.[11] The price of the NYCA 30-minute reserves has accounted for most of the overall day-ahead market reserve procurement costs in recent years, although the share resulting from the 10-minute spinning and 10-minute total reserves components grew considerably in 2022.

G. Significant Market Events

Winter Storm Elliot hit the Northeast region of the US from December 23 to December 27, 2022, causing heavy snowfall, strong winds, and freezing temperatures. The extreme weather conditions put a significant strain on the power grid in the region. NYISO market operations were greatly affected by the Blizzard conditions and rapid temperature drop on December 23 and

[10] 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.

[11] See Appendix Section II.D for additional details about reserve offer patterns.

24, resulting in systemwide reserve shortages for significant periods on the two days. As a result of the reserve shortages, energy prices spiked over $4000/MWh during the period.

The following figures show resource availability during the price spike events on the two days and focus on the performance of the real-time scheduling models (i.e., RTC and RTD). RTD dispatches generation every 5 minutes, while RTC is responsible for committing and decommitting 10-minute and 30-minute quick-start resources and scheduling interchange with neighboring areas. Efficient RTC performance is very important because if RTC fails to schedule a resource that requires 30 minutes to be available, the resource will not be available in the 5-minute dispatch, which may require RTD to schedule a more expensive resource that can be available on shorter notice.

Figure 6 and Figure 7 summarize the availability of supply versus demand and the LBMP in Zone C in each 5-minute interval on the two days. The figures show the following categories:

- *Load + Net Exp* – the amount of NYISO load plus net exports, representing total withdrawals from the system.
- *Load + Net Exp + 1310* – the amount of load plus net exports plus systemwide 10-minute reserve requirements.
- *Load + Net Exp + 2620* – the amount of load plus net exports plus systemwide 30-minute reserve requirements.
- *Non-FS Output* – the total scheduled generation outputs from internal non-fast start resources, including conventional slow-start thermal resources and renewable resources.
- *Net Import* – the amount of net imports across all interfaces between NY and neighboring areas, representing net external supply.
- *FS Output* – the total scheduled generation outputs from internal fast start resources, including gas turbines and flexible hydros that can start up within 10 or 30 minutes.
- *Non-FS Avail 10Min* – the amount of available 10-minute spinning reserves from non-fast start resources that are already online and dispatchable.
- *FS Avail 10Min & 30Min* – the amount of available 10-minute and 30-minutes reserves from fast-start resources.
- *Non-FS Add'l Avail* – the amount of additional head room from online and dispatchable non-fast start resources, which is the unit's UOL less its energy schedule and 10-minute reserve capability.
- *FS MW in MDT* – the amount of fast-start capacity that is during their minimum down time, hence is not capable of providing energy or reserves.
- *Unoffered FS MW* – Fast-start capacity that was in service but not offered into the real-time market largely due to fuel limitations.
- *Derated/FO MW* – Capacity (from fast-start and non-fast start resources) that was offered into the real-time market but is not available because of forced outages or deratings.
- *RTD LBMP* – the 5-minute LBMPs in RTD at Zone C.

These figures stack supply resources to provide insight about what drove reserve shortages on the two days. The available 10-minute reserve offers are stacked first, so systemwide 10-minute reserve shortages are observed when the "Load+Net Exp+1310" line exceeds the top of the "FS Avail 10Min" bars. The available 30-minute reserve offers are stacked next, so systemwide 30-minute reserve shortages are observed when the "Load+Net Exp+2620" line exceeds the top of the "FS Avail 30Min" bars. The top three bars indicate categories of supply that are not available due to forced outages, not being offered, or minimum down time restrictions.

Figure 8 shows net imports across all interfaces between NY and neighboring areas in RTD for each 5-minute interval of December 23 and 24. This is compared to: (a) the level of net imports from the RTC interval that looks ahead 15 minutes, which schedules 15-minute external transactions and commits 10-minute fast-start resources when needed; (b) the average level of net imports from the RTC intervals that look ahead 30 to 75 minutes, which commit 30-minute fast-start resources when needed. The gray-shaded areas in the figure indicate intervals with Simultaneous Activation of Reserve ("SAR") events. Although there were six SAR events, the figure only shows five gray bars as the first two happened in quick succession in hour 17 of December 23, lasting slightly more than one hour. The other four were shorter in duration, lasting 10 to 20 minutes each. The text box in the figure lists the requesting RTO for each event and the amount of reserve support that NYISO was responsible for. The figure shows the net imports scheduled by RTC were often much higher than the actual interchange levels in RTD.

Figure 9 compares, in the upper panel of the figure, RTD LBMPs with RTC LBMPs from two different look-ahead periods in each 5-minute interval of December 23 and 24, one is the RTC interval that looks ahead 15 minutes (labeled as 'RTC LBMP – CTS Evaluation'), which schedules 15-minute CTS transactions and commits 10-minute fast-start resources when needed, and the other is the RTC intervals that look ahead 30 to 75 minutes (labeled as 'RTC LBMP – 30Min GT Evaluation'), which commit 30-minute fast-start resources when needed. In the lower panel of the chart, three quantities are stacked to show the differences in supply between RTD and the RTC intervals that look ahead 30 to 75 minutes: (a) net import over-forecast; (b) load under-forecast; and (c) generation derates. The figure shows that RTC often assumed higher internal generation and imports and lower demand, leading it to shut down or not to start fast-start units that would have been economic.

These figures show that there were three periods of exceptionally high energy prices in the NYISO real-time market. The first period occurred on December 23 from Hour Beginning 17 to 20 (HB17-20). The second and third periods occurred from HB6-9 and HB16-17 on December 24. The results highlight several key aspects of market operations on the two days including: the use of SAR procedures, curtailments of external transactions, and the scheduling of internal 10-minute and 30-minute peaking units. In addition, relatively large quantities of generating capacity were unavailable because of fuel limitations and forced outages.

Figure 6: Resource Availability vs. Load and Reserve Requirement
5-Minute Intervals, December 23, 2022

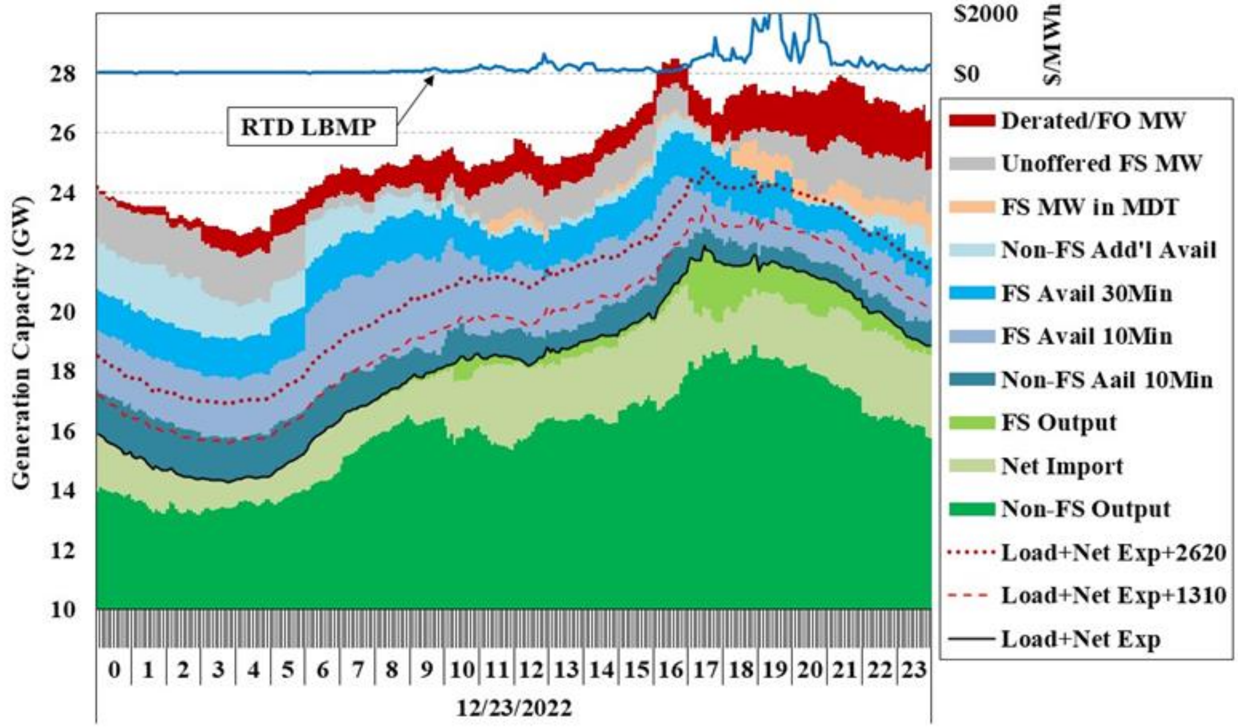


Figure 7: Resource Availability vs. Load and Reserve Requirement
5-Minute Intervals, December 24, 2022

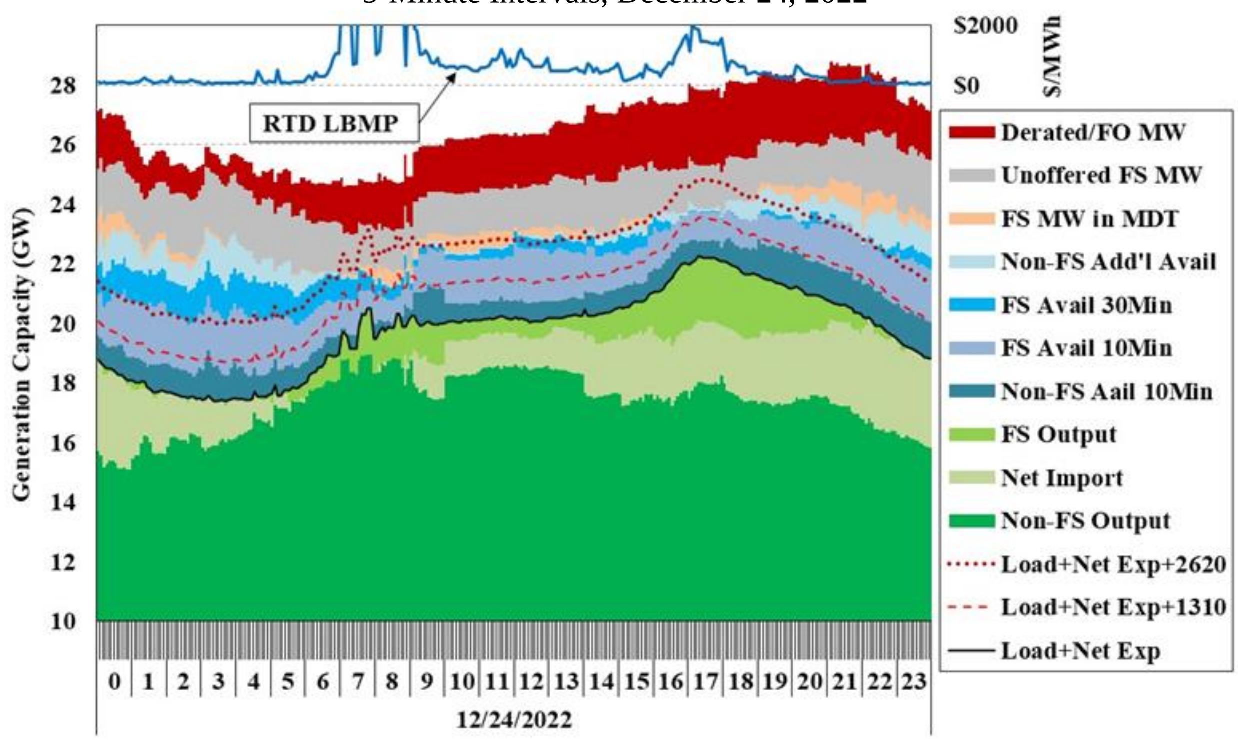


Figure 8: Net Imports in RTC vs. RTD
5-Minute Intervals, December 23-24, 2022

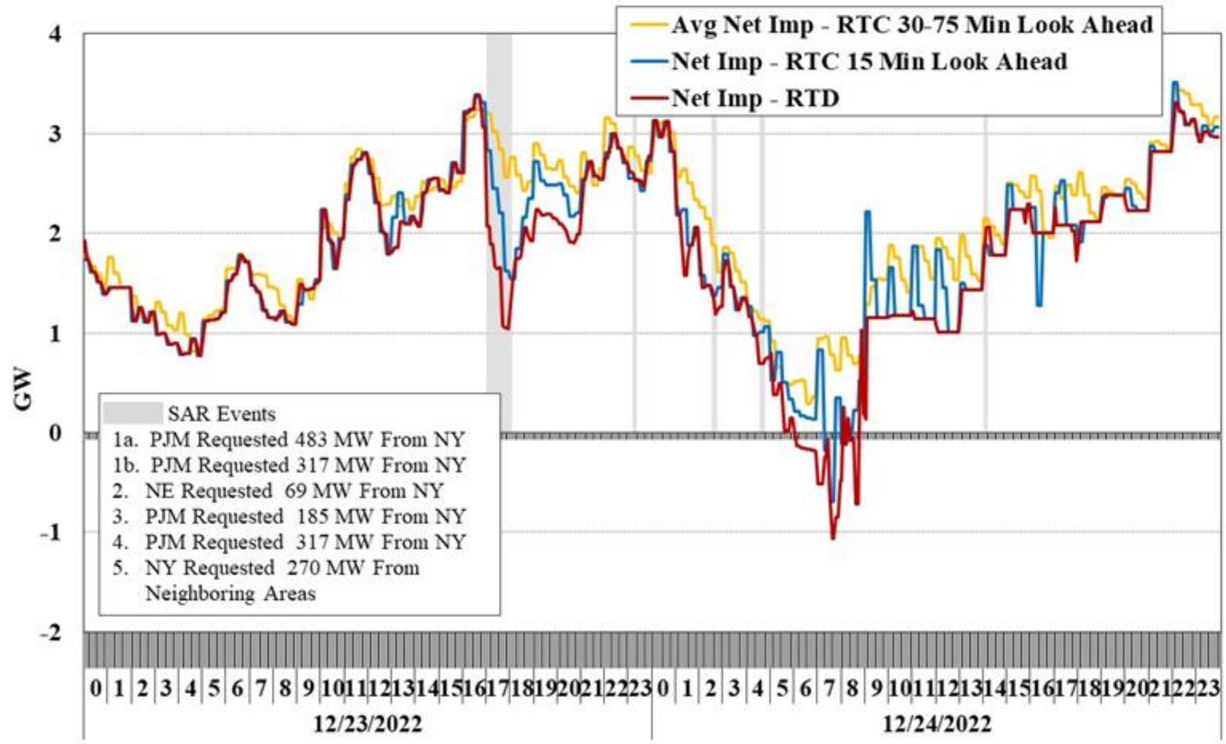
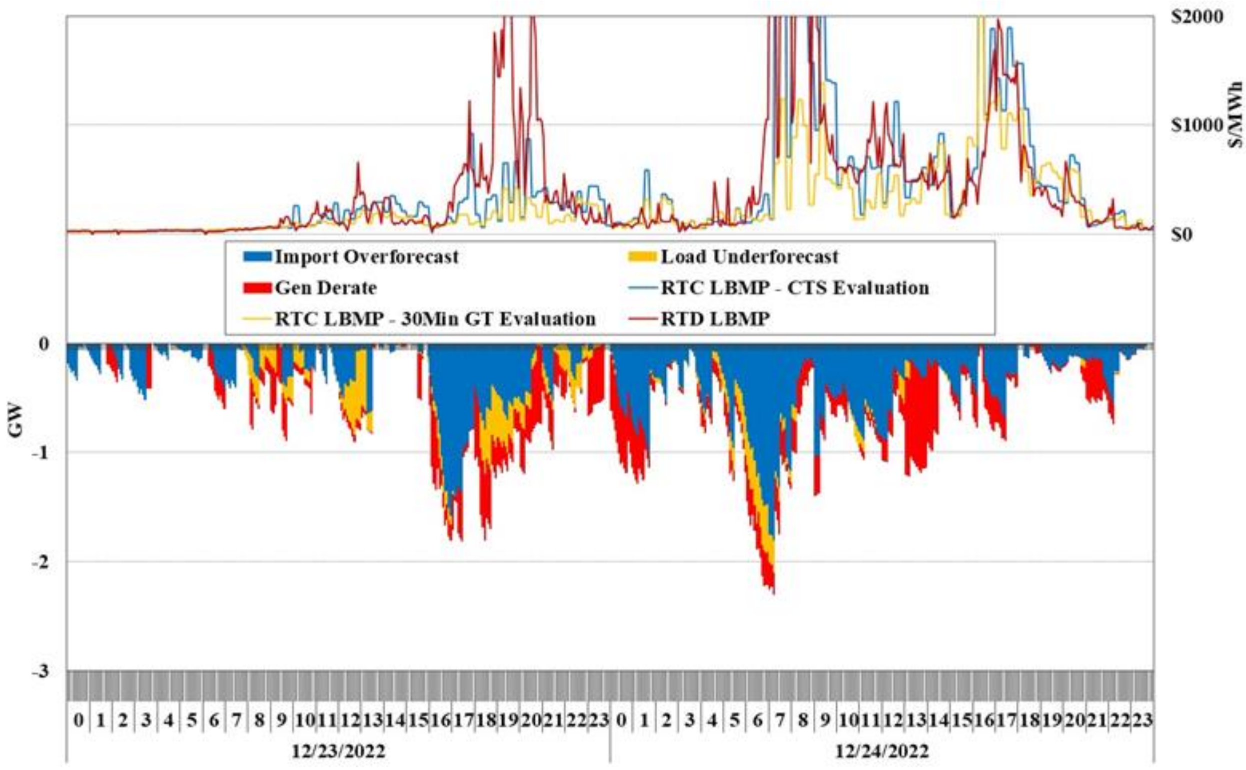


Figure 9: LBMPs, Imports, Load, and Supply between RTC and RTD
5-Minute Intervals, December 23-24, 2022



The following provides a discussion of key factors that affected the balance of supply and demand on December 23 and 24:

SAR Support

As shown in Figure 8, there were multiple requests for SAR support from neighboring RTOs on the two days, including requests during the first price spike event. On December 23 at the beginning of hour 17, PJM requested 3000 MW of SAR support, which was reduced to 2000 MW in the middle of hour 17. Consistent with their SAR agreements, NYISO provided roughly one-sixth of the requested SAR support (~320 MW to 485 MW). Since SAR support requests are typically short (i.e., less than 30 minutes) in duration, they are reflected in RTD but not in RTC, which evaluates periods after the SAR is expected to have already ended. However, on December 23, the first two SAR requests happened in quick succession and lasted for more than one hour, contributing to persistent differences between RTC and RTD during the event.

Curtailments of External Transactions

As shown in Figure 8 and Figure 9, curtailments of transactions to NYISO by neighboring areas were a key contributor to the price spikes. The amount of import curtailments approached nearly 1.5 GW during the first price spike event, 1.8 GW during the second event, and 0.7 GW during the third event. PJM accounted for a significant portion of the curtailments from HB17 on December 23 through HB19 on December 24 under its maximum generation emergency action procedures.

During times of emergency or unforeseen conditions that threaten the reliability of the transmission system, PJM has the authority to curtail transactions scheduled using non-firm and firm transmission service. PJM ordinarily follows the transmission priority of each transaction when determining the order of transaction curtailments, but it may deviate from this order to ensure the reliability of the transmission system.[12] Of the transactions curtailed by PJM on these days with all neighboring areas, approximately 75 percent were non-firm and 25 percent were firm.[13] Of the exports to NYISO that PJM curtailed, 20 percent had firm service.

Fast-Start Capacity Unavailable Because of Minimum Down Time Restrictions

Figure 6 and Figure 7 show that the shutdown of fast-start resources by RTC was also a key driver of reserve shortages. When a fast-start unit is shut down, its capacity is no longer available for energy or reserves during its minimum down time, which is typically around two

12 See PJM OATT § 13.6 and 14.7.

13 These curtailed transactions include transactions between PJM and other non-NYISO markets. See Section 9 – Interchange Transactions in *2022 State of Market Report for PJM* by Monitoring Analytics.

hours. A large amount of fast-start capacity, up to roughly 1 GW, became unavailable in this way during the first price spike event.

In many cases, fast-start units were instructed to shut down when a large quantity of imports was scheduled by RTC, since this made some fast-start units appear to be uneconomic. However, after the fast-start units were instructed to shut down, the imports were cut by another control area operator. For example, from 18:00 to 18:30 on December 23:

- RTC scheduled an average of 1.8 GW of net imports when the average advisory Zone C LBMP was $190/MWh, resulting in the shut-down of 830 MW of fast-start units in the first half of HB18;
- Other control areas cut about 650 MW of imports to the NYCA after the RTC run initialized; and
- RTD set actual LBMPs for Zone C at an average of $816/MWh during HB18.

This demonstrates that one RTC execution run that under-forecasts future needs because of inaccurate input information can prematurely shut down a large amount of fast-start resources during a market event. Therefore, it would be beneficial to consider ways to delay the shut-down of a fast-start resource when it appears economic to remain online (based on information not available to RTC).[14]

30-Minute Resources Not Started by RTC to Address 10-Minute Reserve Shortages

Figure 6 shows that in the first price spike event, when the system was short of 10-minute reserves, more than 1.5 GW of offline 30-minute fast-start capacity was available but not started-up. This capacity was not utilized to address 10-minute reserve shortages because the RTC evaluation that is responsible for committing 30-minute fast-start resources did not accurately forecast the need with sufficient lead time to allow for the commitment of 30-minute fast-start units. Figure 9 indicates that the inaccurate forecasts were driven by a combination of factors including: import curtailments, additional SAR support calls, load under-forecasting, and generation forced derates and outages, which collectively led to nearly 2 GW of equivalent internal generation loss from the RTC evaluation to RTD in HB17 and HB18 on December 23.

Unavailable Supply Due to Forced Derates and Fuel Limitations

Generation derates and fast-start capacity that was not offered into the real-time market made up a large portion of unavailable supply. Figure 7 shows that these categories were the highest during the third price spike event, averaging 3.7 GW with unoffered fast-start capacity accounting for approximately 40 percent of the total. Roughly 80 percent of the unoffered fast-start capacity during these hours faced fuel supply issues. The remaining 20 percent of the

14 SOM Recommendation 2012-13(c) is to enable RTD to delay the shut-down of a gas turbine for five minutes when it deems the unit economic to remain on-line.

unoffered fast-start capacity was associated with resources that are not necessarily staffed if they do not have a day-ahead schedule.

Generator derates and outages over this cold spell mostly resulted from dual-fuel combined cycle generators and peaking plants that experienced mechanical issues during start-up or after performing fuel swaps from natural gas to fuel oil, suggesting some dual fuel units may have higher outage risks while operating on liquid fuel.

Conclusions

We analyzed the scheduling and operation of generators during the three reserve shortage events on December 23 to 24. Of generators that were committed in the day-ahead market or fast-start capable, we found the following categories of supply limitations:

- Unavailable capacity due to forced outages and derates averaged 1.8 GW,
- Unavailable capacity from fuel-limited fast start units averaged nearly 1 GW, and
- Curtailed imports averaged nearly 1.1 GW.

NYISO was also requested to provide up to 483 MW of SAR support during the first reserve shortage event. Furthermore, we find that import curtailments and other unforeseen reductions in supply availability occurred close to real-time, undermining the accuracy of the RTC advisory schedules developed and leading some fast-start units to be shut-down or not started-up. This was most evident during the first reserve shortage, when an average of:

- 470 MW was unavailable on fast-start units after being shutdown while still in their minimum down time period, which is two hours for most units; and
- 1,350 MW of 30-minute fast-start capacity was sitting offline providing reserves (when there was not a significant 30-minute reserve shortage).

Based on these findings, we draw several conclusions regarding market performance during shortage conditions. First, although the current reserve demand curves provide reasonably strong incentives in the real-time market for generators to be available and perform reliably, gas prices were extremely high, leading some units to offer energy near $1,000/MWh and weakening the incentives provided by the shortage pricing levels. Nonetheless, we did not observe RTC making inefficient commitment decisions because the ORDCs were too low (but inefficient commitment decisions resulted from other factors such as frequent import curtailments that were not issued sufficiently far in advance of the relevant interval). In general, ORDCs should be set sufficiently high to: (a) schedule the available resource offers during future periods of extreme gas scarcity and (b) set prices that are consistent with the risks to reliability during a reserve shortage pricing event (as we have recommended in #2017-2).

Second, the amount of fossil-fueled capacity unavailable on these days due to forced outages and derates was around 2.3 GW (including ones reported before the DAM), which was moderately higher than generally expected by the resource adequacy model based on current outage rates.[15] The capacity market is designed to provide dispatchable generators with incentives to be reliable by considering forced outage rates in the qualified UCAP MW of each unit. While a small portion of the forced derates and outages appear to have been driven by weather-related issues, it is important to monitor generator performance during extreme cold conditions to identify any signs of systematic under-performance. Accordingly, we support NYISO's plan to evaluate the potential causes of correlated weather derates in 2023.[16]

Third, substantial amounts of fast-start capacity were unavailable due to fuel limitations on December 23 and 24. NYISO is working on enhancements to improve the capacity accreditation for non-firm fuel generators and duration-limited resources. We support NYISO's plan to make these enhancements in 2023.

Fourth, interchange scheduling is normally driven by market incentives with firms flowing power from low-priced regions to high-priced ones, but under peak demand conditions interchange is also greatly affected by operator actions. We observed that when transaction curtailments occurred outside the normal scheduling process after RTC determined whether to commit peaking units (by operators in other control areas), RTC committed fewer fast-start units than would have been economic, resulting in higher prices and more severe shortages than would have been efficient. Hence, under peak conditions, when a neighboring system is in an emergency, it may be appropriate to schedule additional reserves to the extent that the NYISO relies on imports that have a higher likelihood of being curtailed.[17]

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15 Appendix Section VI.C provides average winter EFORd levels by region and unit technology type.

16 See 2022 Master Plan project *Improving Capacity Accreditation*, November 2022.

17 For example, this could include non-firm transactions sourcing from a control area that is in EEA1 conditions or some operating condition in which the neighboring control area typically curtails exports. It could also include transactions that are bid price-sensitively into the neighboring market and which, thus, can be economically curtailed by the neighboring area after being scheduled by RTC.

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 investment 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 incentives under recent conditions from the NYISO markets and government policies to promote clean resources (subsection A),
- Long-term incentives for investment in renewable generation (subsection B), and
- Signals for investment in energy storage resources that facilitate the integration of intermittent renewables (subsection C).

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:

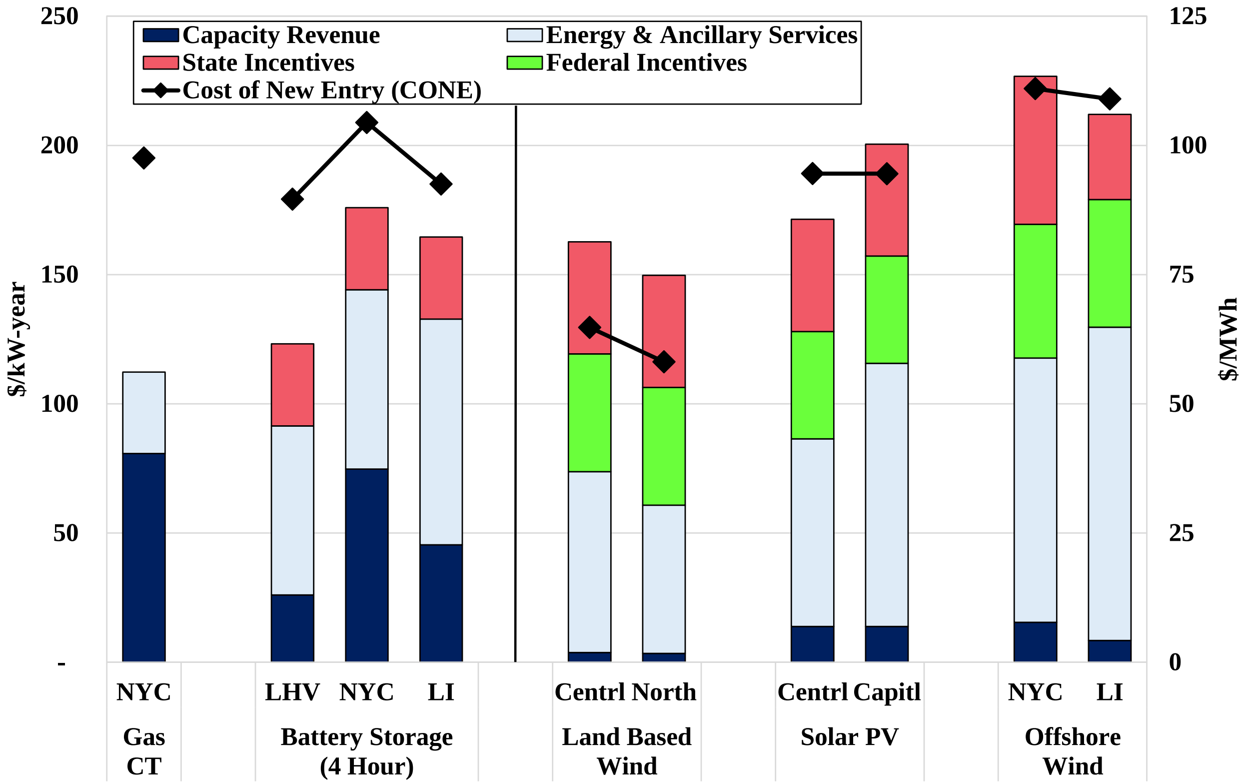
- *Developers of new intermittent renewable generation* – These firms have choices about where to locate and what technologies to use for specific projects. The wholesale market rewards firms that can avoid transmission bottlenecks and generate at times that are most valuable. Developers that expect to receive more in wholesale market revenues will tend to submit lower offers in state solicitations and, therefore, are more likely to be selected.
- *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.

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 10 shows the estimated average net revenues from the NYISO markets, as well as state and federal subsidies, for several technologies and locations. We compare this to their respective gross costs of new entry (CONE) in 2022.[18] Net

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

revenue is the total revenue that a generator would earn less its variable production costs. When these revenues exceed CONE, investors will recover their capital costs plus a required return based on a typical cost of capital.[19] Revenues and costs for H-Class gas combustion turbines and battery storage are shown in dollars per kilowatt-year, while those of wind and solar resources are shown in dollars per megawatt-hour.

Figure 10: Net Revenue and Cost of New Entry for New Resources
2020 – 2022



The profitability of generation investment varies by technology and zone, and it has been influenced by volatility in energy and capacity markets over the past three years. In addition to NYISO market signals, availability of federal and state incentives plays a major role in the profitability of potential projects. We observe the following for specific technologies:

Gas-fired Combustion Turbines – Estimated annual revenues for new CTs were well below CONE due to large capacity surpluses in recent years.[20] Capacity revenues for a new CT in New

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19 The cost of capital for combustion turbine and storage technologies was assumed to be equal to the merchant weighted average cost of capital (WACC) from NYISO's latest Demand Curve Reset study, while the cost of capital for renewables is assumed to be a hybrid between merchant and regulated cost of capital that reflects the large share of subsidy payments with lower risk than market revenues earned by these projects. See Appendix Section VII.C.

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

York City would have been just $33 per kW-year in 2022, the lowest since the inception of the capacity market. Pending retirements in New York City in May 2023 to comply with NYDEC emissions regulations are expected to significantly increase capacity prices and will improve the economics of new or repowered peaking facilities.[21] However, recent permitting decisions suggest a new combustion turbine will not be deemed compliant with state climate law.[22]

Energy storage – Estimated annual revenues for four-hour battery storage projects from 2020 to 2022 were below CONE even after including state incentives. Storage revenues were strongest in New York City, where capacity prices are highest, and in Long Island, where potential energy arbitrage net revenues are highest. The economics of battery storage will improve considerably as standalone storage placed in service after 2022 is eligible for a 30 percent federal Investment Tax Credit.[23] Rising capacity prices driven by retirements of units affected by NYDEC emissions regulations will also improve the revenues of batteries, especially in New York City.

In the long term, storage revenues are expected to be supported by rising intermittent renewable penetration, but capacity revenues will be negatively affected if large amounts of new storage driven by state mandates cause the capacity value of storage to decline.[24] This illustrates how future changes in state and federal policies pose risks to clean resource developers that enter the market before such changes are enacted.

Renewable generators – Estimated annual revenues of land-based wind projects and solar PV projects at some locations were high enough to recover the resources' CONE. This was driven by energy prices in 2022 that were much higher than recent historical averages, especially in eastern New York. Federal and state incentives comprised roughly half of revenues for land-based renewable projects at the locations shown. For offshore wind, total revenues were close to CONE because the Index OREC payments to offshore wind projects are designed to provide a hedge against energy and capacity prices. Site-specific factors including permitting opposition, interconnection costs and nodal pricing discounts may limit the ability of many projects to realize the profitability indicated by Figure 10. We discuss factors affecting the market incentives of clean energy resources in the following subsections.

21 Some of these resources will retire, while others will remain in service but cease operating during the ozone season (May through September), which includes most of the critical summer capability periods. For a list of resources' compliance plans, see Tables IV-5 and IV-6 of NYISO's 2022 Gold Book.

22 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.

23 McGuire Woods, "Inflation Reduction Act Creates New Tax Credit Opportunities for Energy Storage Projects", December 27, 2022, available here.

24 Figure 10 assumes the currently effective 90 percent capacity value for 4-hour storage resource.

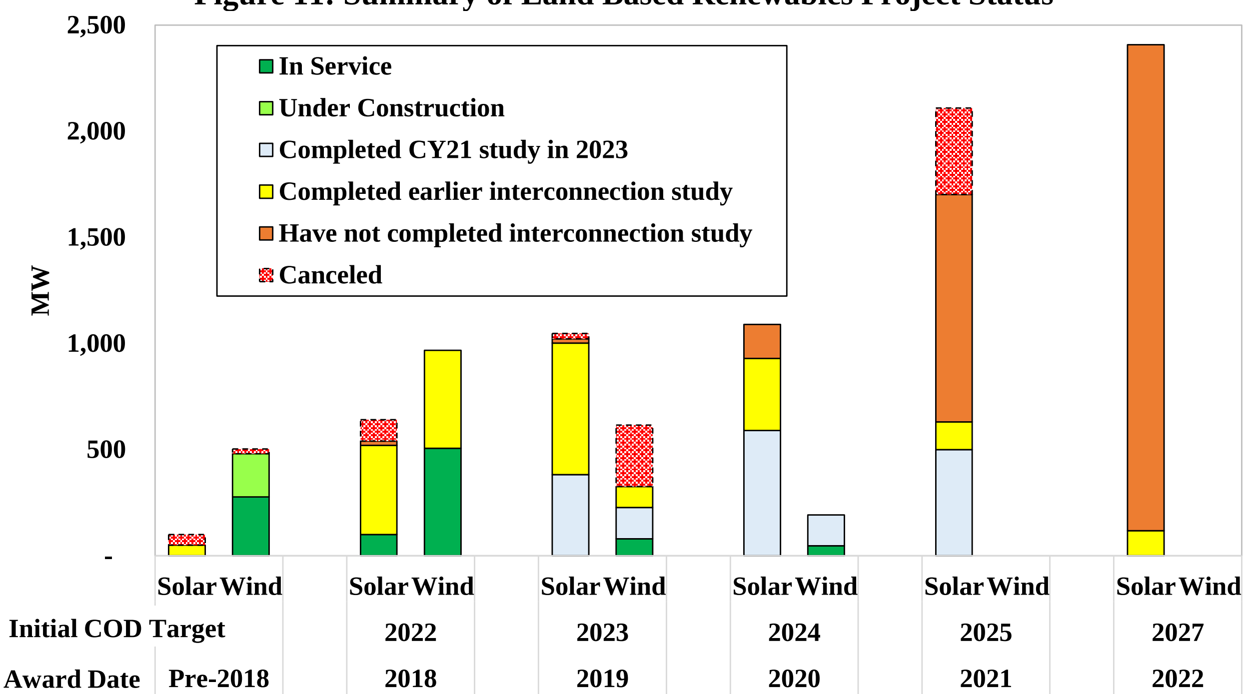
B. Long-Term Incentives for Investment in Renewable Generation

New York's Climate Leadership and Community Protection Act (CLCPA) requires 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 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. This subsection reviews the progress towards policies to promote clean renewable energy projects in NYISO and discusses how current investment incentives are affected by both current and future state policies.

1. Status of Clean Energy Investment in NYISO

Figure 11 shows a summary of land-based renewable projects that have been awarded contracts to provide renewable energy credits (RECs) under New York's Clean Energy Standard (CES), with their status in NYISO's interconnection queue as of March 2023. Awards that NYSERDA indicates have been canceled are shown in red.[25]

Figure 11: Summary of Land Based Renewables Project Status



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25 Data taken from NYSERDA's renewable project database (see here) and NYISO's Interconnection Queue as of March 2023. Initial COD Targets are from NYSERDA announcements of solicitation results (see here).

Overall, while 9.7 GW of land-based renewable awards have been announced under the CES:

- 1.0 GW have entered service and 0.2 GW are listed as Under Construction in NYISO's interconnection queue; but
- 0.9 GW have been canceled,
- 1.8 GW completed the Class Year interconnection study in January 2023 and accepted their interconnection cost allocations,
- 2.2 GW completed an earlier interconnection study (primarily Class Year 2019, which completed in 2021) but are not listed as under construction, and
- 3.6 GW have not completed an interconnection study.

Many of these will have the opportunity to join the next Class Year study in 2023. Earlier solicitations primarily resulted in awards to wind projects, but more recent solicitations have exclusively resulted in awards to solar projects.

Since the earliest awards shown in Figure 11, there have been dramatic changes in State policies to promote renewables. Projects awarded before 2020 were proposed when State policy was to obtain 50 percent of energy from renewables by 2030. As State policies have become more ambitious, anticipated energy and capacity net revenues have declined, requiring higher State and federal subsidy levels to support new clean projects. However, projects that enter earlier before the announcement of a new policy goal and that would rely partly on wholesale market revenues will be harmed by the resulting decline in energy and capacity net revenues. This may affect projects that won an earlier solicitation by hampering their ability to obtain financing and reducing their incentives to complete the permitting and construction of the project.[26]

In addition to land-based renewables, state programs seek to encourage deployment of offshore wind and energy storage. The CLCPA requires:

- 9 GW of offshore wind by 2035 – NYSERDA has procured 4.2 GW of offshore wind from four projects. Filings by the only project to complete a Class Year study (the 816 MW Empire Wind project in New York City) indicate a target COD in December 2026.[27]
- 3 GW of energy storage by 2030 – The NYPSC is currently considering a target of 6 GW by 2030, including procurement of at least 3 GW of additional bulk storage participating in the NYISO markets. Since 2018, the state has awarded incentives to over 1 GW of utility-scale storage projects, including 240 MW paired with renewable projects.[28] However, only 80 MW of battery storage has entered service to date. Over 1.7 GW of

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26 In late 2020, the NYPSC issued an order authorizing renegotiation of REC contracts awarded from earlier solicitations to use an Index REC structure providing greater protection from market risk, acknowledging that adverse market conditions had limited the ability of contracted projects to obtain financing. See here.

27 See Utility Dive, "Empire Wind pushes opening of New York's first offshore wind farm to 2026", October 15, 2021, available here.

28 See NYPSC Case 18-E-0130 and December 28, 2022 NYSERDA Energy Storage Roadmap.

storage has completed a Class Year interconnection study, but only 1.1 GW of these obtained rights to participate in NYISO's capacity market (CRIS) and none are listed as currently under construction.[29]

Overall, state policy requires large amounts of new large-scale resources. The State has awarded many contracts, but deployment of renewables and storage has lagged behind expectations. Contracted projects have faced headwinds including permitting opposition, interconnection costs and delays, cost pressures in recent years, and the impacts of the COVID-19 pandemic. Developers have also reported NYISO market conditions as a major source of difficulty in obtaining financing.[30] The remainder of this subsection considers long-term NYISO market incentives for investment in renewable generation.

2. Long-Term Incentives for Investment in Renewables

Investment in renewables is supported by a combination of NYISO market revenues and state and federal incentives. Renewable projects that earn higher market revenues reduce the costs of achieving state goals, because they provide more benefits to consumers and require lower subsidies. State programs provide additional revenues to renewable projects and hedge against some market risks, but they also have impacts on the NYISO markets that may increase the risk of investments. Hence, it is not possible to assess incentives for investment in renewables without considering the interplay between state programs and the NYISO markets.

New York's procurements for renewable energy have generally been designed to hedge against some market risks while retaining incentives for developers to maximize project value. Most large-scale renewables under contract with NYSERDA will receive payments under the Index REC structure. Under this structure, the project's REC price in each month is equal to a fixed strike price minus 'index' energy and capacity prices derived from zonal average prices. Hence, the project is hedged against changes in overall energy and capacity prices, but faces market risks related to its location and generation pattern:

- Nodal Discount – revenues of renewables will deviate from their Index REC strike price if the LBMP at the project's location differs from the capacity zone where it is located due to transmission constraints;

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29 Some storage projects that completed a Class Year study received only rights to sell energy (ERIS) because they rejected interconnection cost allocations needed to obtain CRIS. See Section IV.A. Most storage projects are unlikely to be economic without capacity revenues.

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

- Technology Discount – revenues of renewables will deviate from the Index REC strike price if prices during hours when the renewable resource generates are lower than the average price across all hours. For example, if high wind penetration in an area causes the zonal price to be lower during high-wind hours, wind generators will face a technology discount.

Figure 12 shows estimated technology discounts in NYISO's 2021 System & Resource Outlook ("Outlook") policy case.[31] This study modeled achievement of NYISO's renewable targets with 19 GW of utility-scale renewables by 2030 and 36 GW by 2035. The "Zone" price represents the average zonal LBMP across all hours of the year, while the technology-specific prices represent the zonal LBMP weighted by each technology's capacity factor in each hour.

As deployment of renewables rises to very high levels, large technology discounts emerge for resources with correlated output patterns. For example, as utility-scale solar in the Outlook increases from 4.7 GW in 2030 to 13.4 GW in 2035, the technology discount of solar in the Capital zone grows from 13 percent of the zonal price to 45 percent.

Figure 12: Zonal LBMPs and Technology Discounts in Outlook "S2" Case

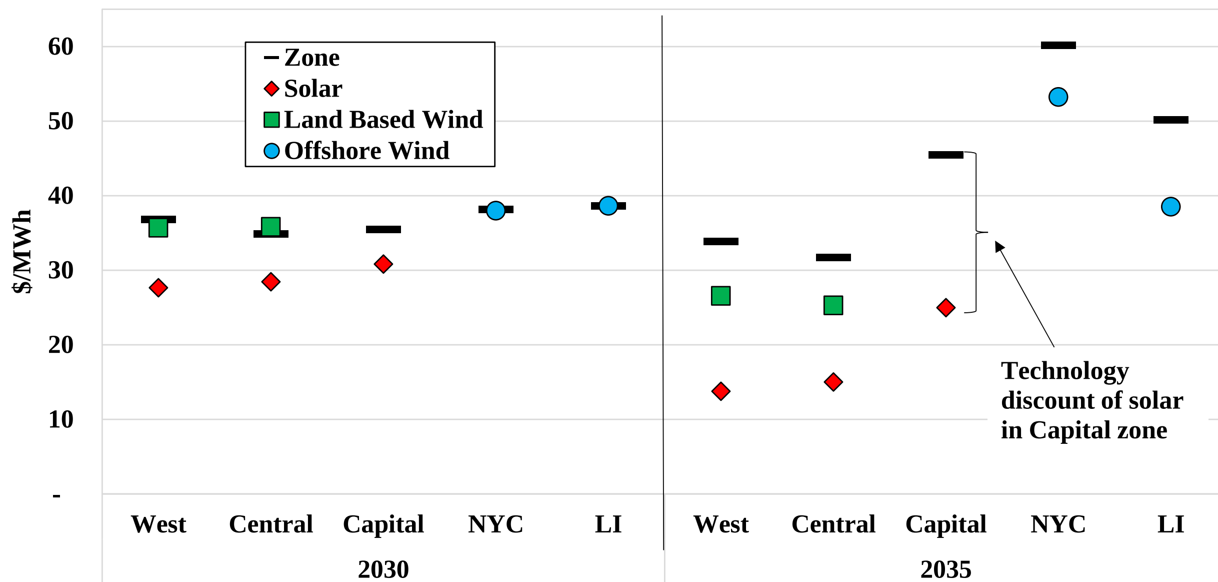
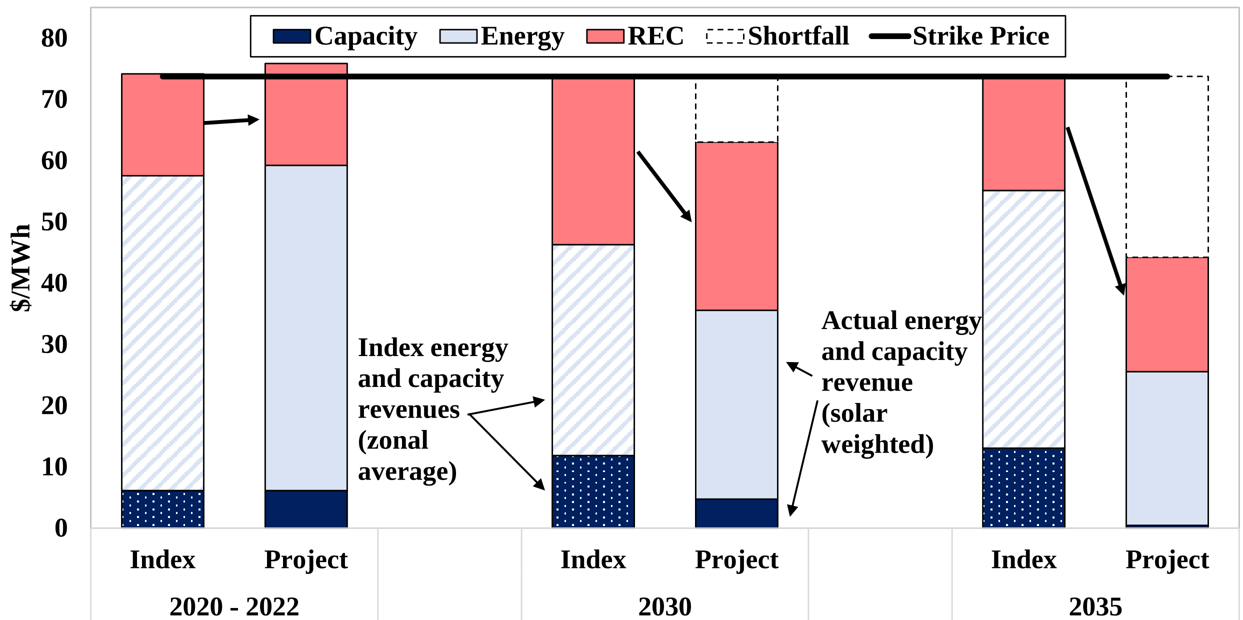


Figure 13 shows how procurement mandates could lead to risk for renewable projects receiving Index REC payments. It shows calculation of Index REC payments and market revenues in the 2021 Outlook policy case for a hypothetical solar project entering service in the Capital zone in 2022. The Index REC strike price is assumed to be the CONE of the resource in 2022. The bars labeled as "Index" show the calculation of the average REC price in each year, based on average zonal energy and capacity prices. The bars labeled as "Project" show projected market revenues for the project in that year, including REC revenues calculated under the Index REC approach.

31 Figures in this section use results from the "S2" Outlook case reflecting state policy targets. See here.

Figure 13: Index REC and Revenues of Solar Project in Outlook "S2" Case



Since the Index REC calculation arrives at a REC price by subtracting *average* NYISO market prices from a strike price, the renewable resource in Figure 13 fails to recover its CONE over time as rising solar deployment causes it to face a growing technology discount. Some efforts to improve the competitiveness of renewables, such as transmission projects designed to reduce nodal discounts, may further exacerbate technology discounts by increasing oversupply of renewable energy across zones or the ISO as a whole in certain hours.

Based on the preceding analyses, we draw the following conclusions:

- NYISO market signals support efficient achievement of renewables targets by signaling the non-REC benefits of competing projects. Exposure to market risks incentivizes investors to avoid projects in oversaturated locations or technologies. This will lower the cost of achieving policy objectives as projects earning higher market revenues require less support from the state.
- Use of long-term PPAs to satisfy clean energy policy goals create risks for current renewable projects. This is because future projects that may receive higher levels of state support will impact the market revenues of earlier entrants by exacerbating technology and nodal discounts.[32] This risk may lead to developers requiring higher Index REC strike prices or to investors reconsidering their decision to invest in a project. Policy initiatives that work through transparent uniform market signals reduce the associated risks and are likely to achieve their objectives at a lower overall cost.

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32 A related phenomenon is that future projects with higher REC payments than existing resources may profit by 'undercutting' the negative offer of the lower-REC project in NYISO's merit order dispatch, causing the new project to earn profit by "cannibalizing" the REC of the earlier project. See MMU Review of 2021-2040 System & Resource Outlook, available here.

C. Long-Term Incentives for Investment in Storage

NYISO has seen little bulk storage deployment despite the establishment of a State energy storage procurement target and incentive programs in 2018. Subsection A suggests that potential storage revenues have simply been insufficient to justify investment in recent years, even after accounting for state incentives. 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. Overall, we find that NYISO markets can efficiently support storage deployment, although we recommend market enhancements to improve the efficiency of price signals that would encourage the development of flexible resources.

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 to manage congestion, allowing more load to be served by renewable sources. More generally, storage can charge when lower-emitting resources set low 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.

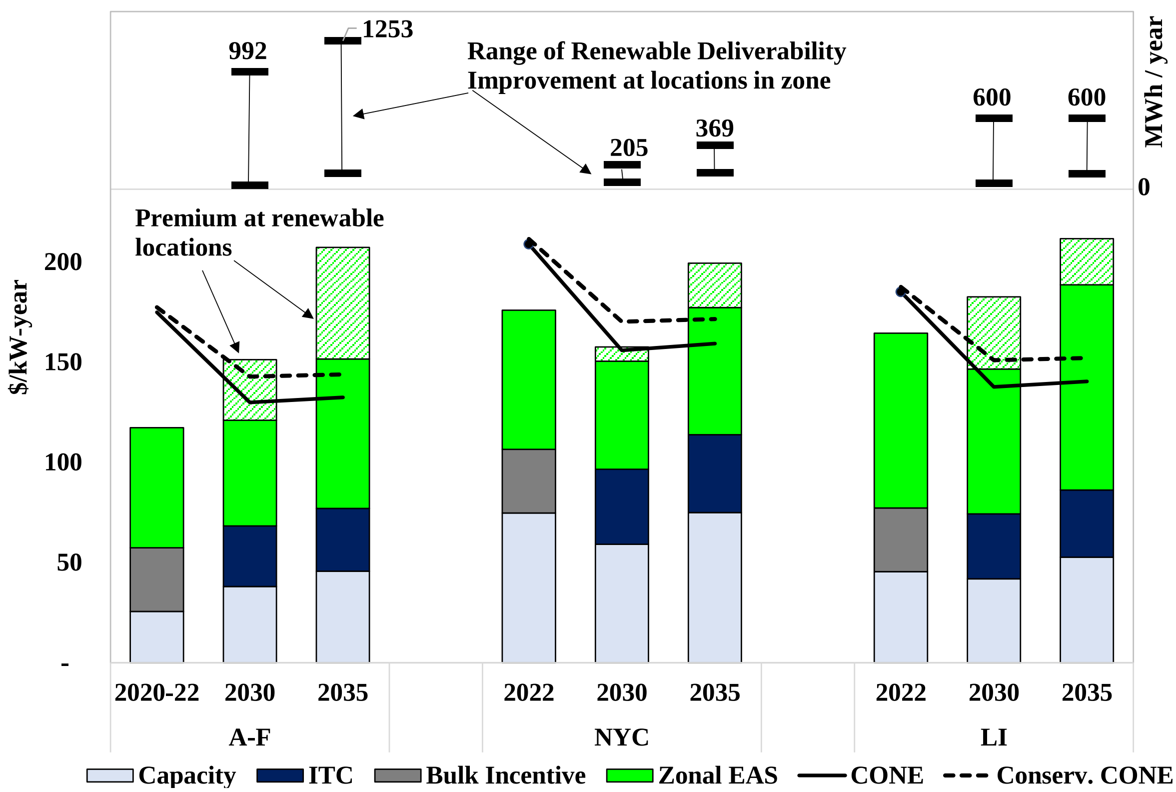
Considering these sources of value, it is unsurprising that potential market revenues of storage have not justified investment in recent years. Renewable curtailment (and hence, the opportunity for storage to profit by relieving it) has been limited, and there have been persistent capacity surpluses. Storage resources that entered service have largely pursued ancillary services revenues. These circumstances are likely to change as larger amounts of intermittent renewables are deployed in New York. In the remainder of the section, we examine market incentives for storage to provide the services listed above.

3. Market Signals for Storage – Renewable Energy Integration

Storage is appropriately compensated for reducing curtailment if LBMPs reflect the environmental value of renewable generation. This happens when: (a) fossil-fuel generator offers include input costs from a carbon pricing program, or (b) renewable generator offers reflect REC payments and/or federal Production Tax Credits ("PTCs") as a negative input cost. In New York, fossil-fuel generator offers include input costs from a cap-and-trade program ("the Regional Greenhouse Gas Initiative"), but contracts for RECs and PTCs are currently the primary mechanism for supporting utility-scale renewable generation 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 (and the associated PTC for some generators). Hence, negative prices serve a valuable purpose because they accurately indicate when additional storage would support clean energy goals.

Figure 14 shows estimated net revenues of a 4-hour energy storage project using hourly prices derived from the Outlook policy case for 2030 and 2035, compared to the last three years. The solid green bar shows a conservative estimate of the energy arbitrage revenues of storage using a model that considers only day-ahead energy and reserve prices (and not real-time balancing revenues, which are expected to be significant for storage). The shaded green bar shows the potential range of additional energy revenues for each region from charging to reduce curtailment at locations of renewables. We assume capacity prices consistent with estimated going-forward costs of existing units in each zone. Storage revenues are compared with CONE values based on 'moderate' and 'conservative' projections by NREL. Figure 14 also shows the range of Renewable Deliverability Improvement (RDI) values for a new 4-hour storage resource at locations in each zone.[33] The RDI is annual MWh of renewable curtailment that an additional 1 MW of installed capacity of 4-hour storage would prevent from being curtailed each year by economically charging when curtailment would occur.

Figure 14: Storage Revenues and Curtailment Reduction in Outlook Policy Case



33 The RDI and other metrics for assessing the economics of investments in clean energy resources are described in "MMU Review of 2021-2040 System & Resource Outlook", August 2022, available here.

Figure 14 suggests that as intermittent renewable generation increases, storage projects will have the opportunity to earn higher energy market revenues. As a result, storage earning only NYISO market revenues may become economic at many locations. This is particularly true for projects at locations where charging the battery will reduce renewable curtailment, allowing the storage owner to capture REC revenues. Hence, NYISO market prices will efficiently reward storage resources that reduce curtailment of renewables and signal for investment in storage when it can cost-effectively relieve curtailment, even in the absence of additional subsidy payments.

This analysis demonstrates how energy 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 renewable generation in an area is rarely curtailed, revenues to storage will be smaller because storage would not marginally increase the amount of renewable generation that can be utilized. On the other hand, if renewable curtailment is widespread in an area, it may indicate that transmission investment would be more cost-effective at reducing curtailment than energy storage investment. Ultimately, NYISO prices signal the locations where storage investment would be efficient for reducing curtailment of renewables.

4. Market Signals for Storage – Capacity Value

NYISO recently made tariff changes that will accredit all capacity suppliers based on their marginal impact on reliability.[34] 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. In the marginal accreditation framework, this value is reflected in higher capacity payments to storage.

Figure 15 shows simulated marginal capacity value of 4-, 6- and 8-hour storage in New York City in 2030 as systemwide storage deployment increases.[35] We use a projected 2030 load shape and assume that renewable resources contracted by NYSERDA to date are in service. We developed these values using a simplified model that simulates key features of marginal capacity accreditation.[36]

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34 See FERC Docket ER22-772, Section VIII.F, and Appendix Section VI.H.

35 We assume that systemwide storage is deployed in proportion to zonal peak load.

36 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. Capacity Accreditation Factors (CAFs) will differ due to differences in the future load and resource mix as well as model inputs and techniques. We have recommended improvements to the modeling of energy storage in GE-MARS for purposes of establishing capacity accreditation values, as discussed in this section.

Figure 15: Storage Marginal Capacity Value by Duration and Quantity
New York City

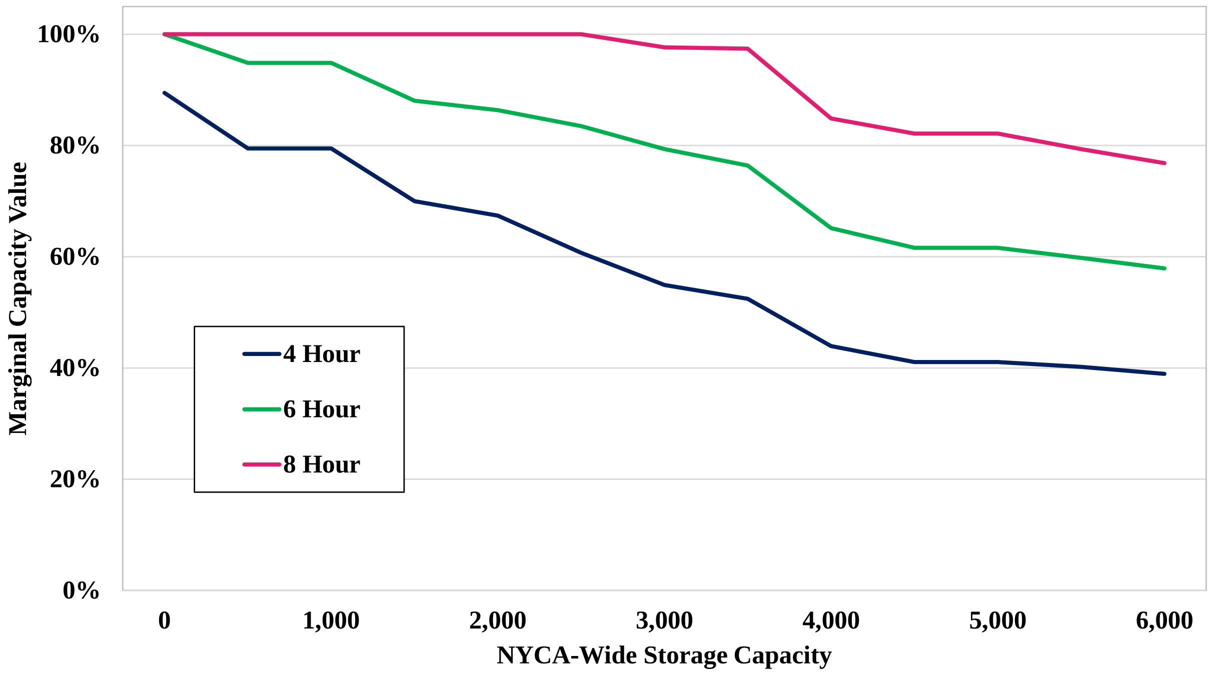

Figure 15 shows a declining marginal capacity value of storage as its penetration increases. This is because the average duration of critical reliability periods increases when a larger share of the system's capacity is energy-limited. This analysis suggests that for a given level of renewable penetration, there is an efficient level of storage investment in the system, which is signaled by market prices. If storage investment is low relative to renewables, storage resources will then have high energy and 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.

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.[37]
- **Recommendations #2022-4 and 2013-1c** – These recommendations are designed to improve the locational pricing of capacity, which would create opportunities for storage investments to target areas where new capacity would be valuable, especially export-constrained areas with high renewable penetration where energy storage resources could be available during periods of low renewable production. They would also reduce

37 See Section XII and Section VIII.F.

barriers to storage in the interconnection process by treating new and incumbent resources equally when transmission bottlenecks limit deliverability.[38]

5. 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. As intermittent generation increases, the need for system flexibility is also likely to increase. However, the current reserve markets are not designed to fully price these needs and should be improved so that the value provided by flexible resources is reflected in market clearing prices.

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:[39]

- **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.
- **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.

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38 See Section XII and Sections IV.A and VIII.E.

39 See Section XII.

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-on that value to storage resources to the extent that they facilitate integration of renewable generation. Similarly, as renewable penetration grows, capacity and ancillary services markets will reward energy storage for facilitating additional renewable production. If State mandates target a minimum amount of installed energy storage capacity that exceeds efficient levels, it will drive-up long-term contract payments and crowd-out market-based storage investment.

We identify aspects of the NYISO markets that should be improved to ensure that energy storage is efficiently compensated, including features of the capacity and reserve markets. Our recommended enhancements would create stronger financial incentives to invest in energy storage resources at times and locations where it would be valuable in integrating renewable resources.

Finally, the next section discusses transmission planning and investment. Among the conclusions of that section is that storage is often a much lower cost means to facilitate the delivery of clean energy than building new transmission. When this is true, it is important to avoid building transmission inefficiently because it will undercut the incentives of storage developers.

IV. DELIVERABILITY TESTING AND TRANSMISSION PLANNING PROCESSES

New transmission investment in the bulk power system occurs through centralized planning processes including: (a) NYISO's Comprehensive System Planning Process, (b) processes led by utilities and State agencies, (c) the deliverability testing process to identify upgrades are funded by resource developers, and (d) processes supporting merchant transmission upgrades by private developers that earn wholesale market revenues and/or contracts with load serving entities.

Two of the most essential NYISO processes that facilitate efficient investment in transmission, generation, and other resources are the deliverability testing process and the centralized planning process. As the NYISO's MMU, we assess both of these processes to evaluate their economic performance, including identifying gaps and opportunities for improvement. The first subsection contains our evaluation of the interconnection process with a focus on the deliverability study framework while the second subsection discusses NYISO's centralized planning processes.

A. Evaluation of the Deliverability Study Process for New Resources

NYISO's interconnection process plays a key role by ensuring that new resources can reliably interconnect to the network and be deliverable to load in a given Capacity Region. All new generation and storage projects must complete the deliverability testing process, which seeks to transparently and accurately identify the upgrades needed for a project to be deliverable. Upgrade costs are allocated to the interconnecting projects to provide incentives for developers to consider transmission limitations when deciding whether to move forward with a project. At the same time, new projects should not bear a disproportionate share of the upgrade costs that benefit the system as a whole, since this will deter efficient new investment.

The interconnection process consists of multiple studies. After completing an Optional Feasibility Study (FES) and System Reliability Impact Study (SRIS), which evaluate the impacts of the individual project on system reliability and transfer capability, the project must complete the Class Year Study, which jointly evaluates the impacts of a group of projects.[40] The Class Year Study consists of two components:

- The System Upgrade Facilities ("SUF") Study identifies network upgrades needed for the group of studied projects to comply with NYISO's Minimum Interconnection Standard ("MIS"). Projects must agree to pay the cost allocated to them for upgrades identified in the SUF Study to receive the right to sell energy (ERIS). The MIS is designed to identify adverse reliability impacts resulting from the projects' interconnection, but considers the

40 This section generally applies to large generators that participate in the Class Year process. Different rules apply to very small generators. Projects requesting only CRIS may participate in an Expedited Deliverability Study which uses a similar methodology to the SDU Study. For additional details on the interconnection process, see NYISO's Transmission Expansion and Interconnection Manual, available here.

potential for normal operating actions that would avoid these impacts (e.g. reduction in output or curtailment of the resource as needed).

- The System Deliverability Upgrade ("SDU") Study identifies upgrades needed for resources to be considered deliverable under NYISO's Deliverability Interconnection Standard (DIS). Projects must pay for upgrades identified in the SDU study to receive the right to sell capacity (CRIS). The DIS ensures that all new projects receiving CRIS rights and all existing resources can simultaneously deliver their output throughout the capacity zone in which they are located without violating any transmission constraints.

After the Class Year Study is completed, the developer must chose whether to pay for required upgrades to receive ERIS or CRIS rights, or to withdraw. The number of resources participating in the Class Year studies and the resulting upgrade costs have increased in recent years. Recent studies have taken approximately two years to complete. During this time, new resources seeking to interconnect that are not part of the Class Year Study must wait until it is completed and a new study begins. If the Class Year Study identifies the need for SDUs, a preliminary estimate of the SDUs' costs is issued and the affected projects may choose to enter an Additional SDU Study which develops final cost allocations.

Results of Class Year 2021

The most recently completed Class Year study cycle was Class Year 2021 ("CY21"), which began in February 2021 and completed in January 2023.[41] Participants requested approximately 11 GW of ERIS and 10 GW of CRIS. The CY21 SUF Study initially identified over $900 million of required upgrades. Of these, $800 million were "Part 1" upgrades pertaining to direct connection of individual projects to the grid and upgrades at their own points of interconnection while $100 million were "Part 2" upgrades needed for systemwide reliability under the MIS.

Table 2 summarizes the results of the CY21 SDU Study and developers' decisions. It lists all CY21 projects that were found to be not fully deliverable in the preliminary CY21 deliverability report. Sixteen projects requesting over 4 GW of CRIS were not fully deliverable (less than 400 MW from these projects was partially deliverable). NYISO identified $1.5 billion in SDUs (preliminary estimate) for these projects. When allocated to projects, the SDUs range from $468 to $2,557 per kW of UCAP the projects could sell under the current UCAP factors. Table 2 also shows these costs when levelized over a 20-year time horizon as a percentage of the 2022/23 capacity market Net CONE in the same locality.

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41 See public NYISO notices to Class Year participants on NYISO's interconnection process page under "Notices to Market Participants", available here. See also "Class Year 2021 Facility Studies Preliminary Deliverability Analysis Draft Report", July 2022, and "Class Year 2021 Facilities Study System Upgrade Facilities (SUF) and System Deliverability Upgrade (SDU) Report", October 17, 2022. The full reports are posted in NYISO's Transmission Planning Advisory Subcommittee (TPAS) meeting materials and require a MyNYISO account with access to Critical Energy Infrastructure Information (CEII).

Table 2: Summary of CY21 Preliminary SDUs

Area	Queue #	Type	Requested CRIS MW (ICAP)	Deliverable CRIS MW (ICAP)	SDU Cost ($/kW UCAP)		Final Decision
					$ per kW UCAP	Levelized (% of Net CONE)	
Northern NY - Thousand Island	774	Solar	119	55	**1,136**	**140**	Withdraw from CY
	864	Solar	120	55	**1,125**	**139**	Accept partial CRIS (46%)
	881	Solar	100	38	**1,837**	**227**	Withdraw from CY
	882	Solar	100	55	**1,354**	**167**	Withdraw from CY
	953	Solar	125	49	**1,306**	**161**	Withdraw from CY
N.Y.C. - Staten Island	840	Storage	650	121	**795**	**50**	Accept partial CRIS (19%)
Long Island - West	958	Wind	96	0	**528**	**61**	Withdraw from CY
	959	Wind	1260	0	**528**	**61**	Withdraw from CY
Long Island - Central	925	Storage	100	0	**1,206**	**138**	Withdraw from CY
	942	Storage	60	0	**2,557**	**293**	Withdraw from CY
Long Island - East	766	Wind	880	0	**468**	**54**	Accept SDU
	987	Wind	44	0	**468**	**54**	Accept SDU
	956	Storage	110	0	**577**	**66**	Accept SDU
	965	Storage	77	0	**669**	**77**	Accept SDU
	994	Storage	90	0	**610**	**70**	Withdraw from CY
	746	Storage	150	0	**542**	**62**	Withdraw from CY

These preliminary SDUs are likely prohibitively costly for most developers. By the final round of the CY21 study, two projects accepted their partially deliverable CRIS (totaling 176 MW) without committing to further upgrades, five projects (totaling 544 MW) withdrew from the study, and the remaining projects entered the Long Island Additional SDU Study. Ultimately, four Long Island projects totaling 1,111 MW (approximately 519 MW UCAP) accepted their final SDUs, which declined to $116 million ($224 per kW of UCAP) after most of the CY21 participants dropped out.

As Table 2 shows, deliverability upgrades affected a large portion of capacity attempting to interconnect in CY21 and can substantially increase the costs of new resources. Given the scale of new capacity planned in New York, it is critical to accurately consider projects' deliverability and to not inefficiently inhibit new investment. In the remainder of this section, we discuss concerns with NYISO's current deliverability framework.

1. Concerns with Deliverability Framework – the Deliverability Determination

The DIS was designed to ensure that new resources will be deliverable throughout their capacity zone. However, the deliverability framework uses a test methodology that is poorly aligned with the resource adequacy analyses that are the primary basis for determining reliability needs and capacity prices in each region. As participation of renewables and storage grows, the methodology will tend to estimate resources' deliverability inaccurately during tight hours when capacity is most valuable. Consequently, the deliverability framework may identify and allocate excessively large SDUs to project developers. We discuss these concerns in this subsection.

Overview of the Highways and Byways Test

NYISO evaluates new resources' deliverability using a prescriptive methodology defined in the OATT.[42] The "highway/byway" analysis is the primary test resulting in SDUs.[43] It is designed to examine whether all resources within a capacity zone are deliverable throughout that zone under a deterministic set of conditions. It uses the following general procedure:

- The capacity zone is divided into several distinct subzones based on the location of relevant transmission bottlenecks.[44]
- A base case power flow simulation is developed in which total generation in the capacity zone is brought in balance with summer peak load.[45]
- For each subzone, generation in that subzone is increased while generation outside of the subzone is decreased, preserving the balance of generation and load. If this causes a transmission constraint to be violated before all generation in the subzone can reach its maximum level, resources in that zone are considered to be not deliverable.

The highway/byway test is deterministic and models a specific set of conditions representing summer peak load. The model includes all existing resources, new resources requesting CRIS in the Class Year, and proposed resources that obtained CRIS in a prior Class Year. Each resource is modeled with a maximum output level equal to its CRIS MW multiplied by one minus its UCAP Derating Factor (UCDF).

The UCDF is intended to reflect the resource's expected unavailability during summer peak conditions and may differ from its UCAP value used in the capacity market. For dispatchable resources (including energy storage), the UCDF is equal to the average EFORd in the capacity zone. For intermittent resources, it is based on the average output of that resource type during summer afternoon hours. NYISO has recently proposed changes to the calculation of the UCDF for intermittent resources as discussed further below.

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42 See OATT Section 25.7.8. NYCA Deliverability is defined as: "The NYCA transmission system shall be able to deliver the aggregate of NYCA capacity resources to the aggregate of the NYCA load under summer peak load conditions. This is accomplished, in the Class Year Study, through ensuring the deliverability of each Class Year CRIS Project, in the Capacity Region where the Project interconnects."

43 The SDU Study process also includes the interface transfer capability "No Harm" assessment, not discussed in detail here because it has not led to identification of SDUs in recent Class Year studies.

44 These subzones may correspond to individual NYISO load zones within the same capacity zone, or to local areas within one load zone.

45 This is done by scaling all capacity in the zone proportionally to its modeled maximum output level, until total generation is equal to peak load (plus load forecast uncertainty) net of imports from other areas.

The Deliverability Test is Inconsistent with Resource Adequacy and Reality

The deterministic highway/byway test does not represent a realistic or likely dispatch of the system. In fact, when a capacity zone has substantial excess capacity, raising the output to the maximum in one subregion and lowering it in others can produce dispatch conditions that would never be observed in actual operations. Consequently, this test is likely to identify required SDUs to mitigate identified constraints that may never bind in actual operations. This problem is exacerbated by performing the test in relatively large zones with many intrazonal constraints. Hence, defining more disaggregated capacity zones would greatly mitigate the concern.

In stark contrast to the deliverability test, resource adequacy requirements are assessed using a probabilistic framework intended to reflect reality and model conditions that are most likely to lead to capacity and energy shortages. Increasingly, these conditions may not correspond to the deterministic conditions modeled in the deliverability study. Hence, the deliverability test may fail to accurately reflect whether resources are deliverable at the times when they are most needed for resource adequacy. If resources are highly likely to be deliverable during the hours of greatest reliability need, it is inefficient to prevent them from entering and selling capacity or to compel them to incur large SDUs for constraints that would be unlikely to bind in these hours.

Concerns with the Current Deliverability Test for Renewables and Storage

Participation in the Class Year has heavily shifted towards renewables and storage in recent years. Unfortunately, NYISO's deterministic deliverability test tends to overestimate transmission impacts of these resources:

- *The deliverability test overestimates the output of intermittent resources.* It assumes they always produce at their UCDF-derated maximum output. The timing of reliability needs is increasingly likely to coincide with hours when renewable output is low. Since the deliverability test does not account for this, it will overestimate renewable output in hours when capacity is needed and underestimate transmission headroom in those hours.
- *Deliverability test ignores the complementary nature of storage and intermittent renewables*. Storage can support reliability by operating in hours when renewable output is low, but the deliverability test assumes all resources operate simultaneously.
- *Over-assignment of SDUs will grow as energy storage penetration rises*. As storage penetration increases, batteries may be able to support reliability in some cases by operating at a lower output level for more hours. The deliverability test assumes they operate at their maximum output level (derated by a UCDF reflecting forced outage risk).

Hence, the deliverability test is likely to overestimate the need for SDUs as renewable and storage capacity grow. These technologies make up the vast majority of projects in NYISO's interconnection queue. The preliminary SDU assigned to five solar projects in the Thousand Island region of Zone E in CY21 illustrate this concern:

- Of the projects' 564 MW of requested CRIS, 252 MW was found to be deliverable. This implies that 120 MW of UCAP can be simultaneously delivered based on the assumed summer peak solar capacity factor of 47.6 percent.
- By contrast, NYISO recently estimated that the marginal capacity value of solar resources in Zones A-F is 16.7 percent in 2023, meaning that solar resources are expected to have a capacity factor of 16.7 percent on average in hours when additional capacity would improve reliability.[46]
- Hence, the 252 MW of solar CRIS found to be deliverable would have an expected output of only 42 MW (252 MW times 16.7 percent) in tight hours, well below the 120 MW that can be simultaneously delivered.

NYISO recently proposed changes to the calculation of the UCDF for future Class Year studies (the "updated UCDF procedure").[47] Under the new approach, an intermittent resource's assumed output level will reflect its hourly summer capacity factor weighted by the load shedding risk in each hour of day in the latest GE-MARS IRM case.[48] This will help align the modeling of resources that have a consistent output pattern by time of day – such as solar – with the timing of reliability needs. However, it will continue to inaccurately estimate deliverability when resources' output varies in the same hour on different days (for example, a resource with a late afternoon capacity factor of 80 percent on one day and 10 percent the next day). The following analysis highlights inefficiencies that will remain under the updated UCDF procedure.

Analysis of the Deliverability Test Methodology with Updated UCDF Procedure

Recent Class Year studies have identified large SDUs needed for new wind and storage projects in Long Island, including over $900 million in the preliminary CY21 SDU Study. Figure 16 and Figure 17 below illustrate how the deterministic methodology used in the deliverability study will overestimate the transmission headroom needed to make wind and storage on Long Island deliverable during tight hours, compared to the type of probabilistic methods used to project intermittent resource availability in resource adequacy planning analyses. The "updated UCDF procedure" has been developed to address differences between the deliverability test assumptions and probabilistic approaches used in resource adequacy analyses, but the following analyses show that significant differences will remain.

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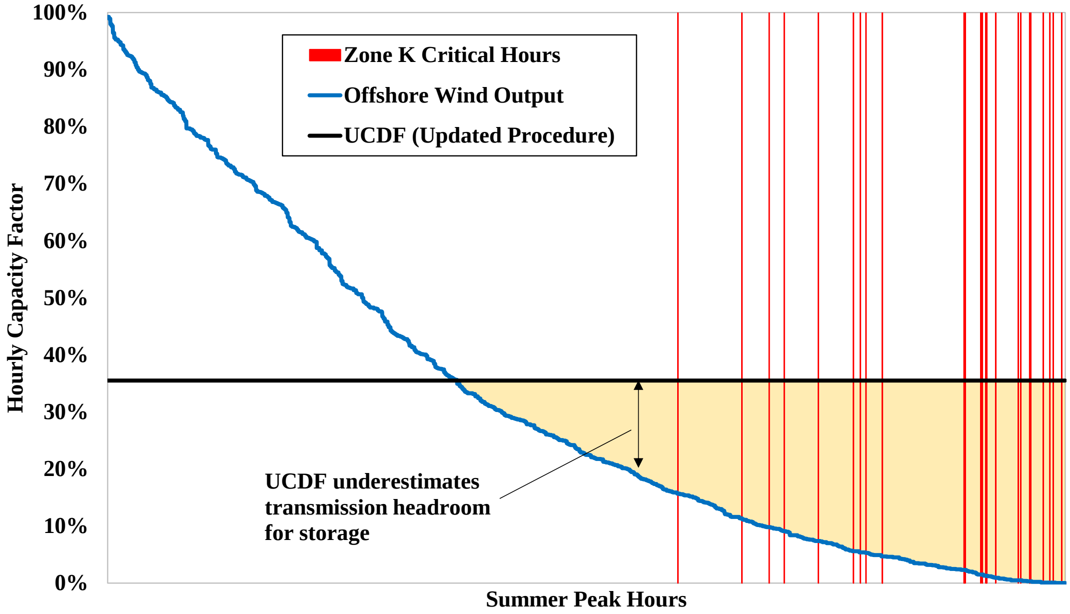
46 NYISO has adopted changes to accredit capacity suppliers based on their marginal contribution to reliability, which largely reflects their expected availability during tight hours. See Section VIII.F. See NYISO presentation to ICAPWG on November 21, 2022 "Capacity Accreditation", available here.

47 See discussion of "Translation Factors for IRM/LCR Studies and Deliverability Testing" in October 19, 2022 ICAPWG presentation "Capacity Accreditation" (available here) and draft ICAP Manual Attachment N published with December 14, 2022 Business Issues Committee meeting materials, available here.

48 For example, if a resource's average output in hours 17, 18 and 19 on summer days is 30%, 40% and 50% respectively, and the proportion of load shedding taking place in hours 17, 18 and 19 in the IRM case is 10%, 20% and 70%, then the resource's UCDF will be {1 – (30% x 10% + 40% x 20% + 50% x 70%)} = 54%.

Figure 16 shows a duration curve of Long Island offshore wind output.[49] The curve shows the wind capacity factor in each hour ending 11 through 18 in June through August, arranged from highest to lowest.[50] The black horizontal line shows the assumed wind output calculated using the updated UCDF procedure. The hourly weights used to calculate the UCDF are derived from a resource adequacy simulation assuming all Long Island offshore wind projects that participated in the past two Class Year studies (3.1 GW of requested CRIS) are in service.[51] The red vertical lines mark the individual critical reliability hours in Long Island in the same simulation.[52]

Figure 16: Long Island Offshore Wind Hourly Output and UCDF in Critical Hours



Critical hours in Figure 16 occur more frequently when offshore wind output is low because high offshore wind output results in a capacity surplus. As a result, the updated UCDF procedure significantly overstates offshore wind output during critical hours. Furthermore, over-estimating the transmission utilization by offshore wind will cause other projects to *appear* undeliverable even if they would be deliverable during the hours of greatest reliability risk. This is particularly

49 The offshore wind output profile shown is based on the assumptions used in NYISO's 2021 System & Resource Outlook study, which are derived from NREL offshore wind profiles.

50 All critical hours in the resource adequacy simulation described here took place in these hours.

51 New York's state climate law required 9 GW of offshore wind by 2035. The state has awarded contracts to 2.2 GW of offshore wind on Long Island to date, with another solicitation underway at the time of writing.

52 Critical hours are in the resource adequacy simulation are defined as hours in which load shedding occurs or hours in which storage resources were discharged prior to load shedding in the same day. The simulation assumes a system at the target level of reliability. It includes internal transfer limits between West, Central and East subzones in Long Island derived from the CY21 Preliminary SDU Study.

problematic for energy storage projects, which would be very effective in generating more during periods of low offshore wind production.

Figure 17 estimates the amount of offshore wind and storage capacity in eastern and central Long Island made deliverable by a given amount of transmission headroom under (1) the deliverability study approach (using the updated UCDF procedure) and (2) a probabilistic approach that considers the marginal reliability impact (MRI) of resources upstream of a potential transmission bottleneck.[53] These amounts are compared to the requested CRIS of offshore wind and storage resources in eastern and central Long Island in the last two Class Year studies.[54] We estimate the amount of capacity made deliverable by a given increase in headroom as follows:

- Under the UCDF approach, we calculate the amount of offshore wind and storage installed capacity that would be made deliverable by a given increase in transmission headroom, considering their assumed output under the updated UCDF procedure. Incremental headroom is assumed to be provided by retirements of existing resources.
- Under the MRI approach, we used an hourly resource adequacy simulation to determine the amount of offshore wind and storage in eastern and central Long Island that would provide comparable marginal reliability benefits to capacity in western Long Island, assuming a given increase in headroom is made available by retirements.[55]
- The yellow diamonds show the capacity value of the wind and storage in eastern/central Long Island that is deliverable under each approach. This is the amount of conventional

53 MRI quantifies the improvement in a reliability metric (such as loss of load expectation or expected unserved energy) provided by an incremental unit of a given type or location of capacity.

54 The deliverability test divides Long Island into West, Central and East subzones. The majority of offshore wind and storage resources in CY21 and CY19 intended to interconnect in Central and East Long Island and faced constraints in the westbound direction. For the purposes of this test, we added wind and storage in fixed proportions matching the composition of the Class Year resources. We also included 1,356 MW of offshore wind requested CRIS in West Long Island that participated in CY21 in the resource adequacy simulation described in this section.

55 We use the following methodology to calculate deliverable MWs under the MRI approach:

First, the resource adequacy model is brought to a target level of reliability consistent with recent IRM studies. Transfer limits are modeled between NYISO capacity zones and between three subzones in Long Island (West, East and Central). We estimated the transfer limits between Long Island subzones based on the results of the CY21 Preliminary SDU Study. In the starting case at reliability criteria, capacity is removed such that available headroom for within-Long Island transfers is zero (e.g., all three subzones have similar MRI but additional capacity in Central or Eastern Long Island would cause the MRI of those zones to fall).

Next, 'perfect capacity' representing conventional generator UCAP is removed from central/eastern Long Island, corresponding to each level of headroom shown in Figure 17. Offshore wind and storage ICAP is then added to central/eastern Long Island, and additional perfect capacity is removed or added in Long Island so that the system returns to the target level of reliability. The largest amount of wind and storage capacity that can be added in this way while maintaining an MRI in each Long Island subzone equal to at least 90 percent of each other subzone is shown in Figure 17.

UCAP in Long Island that can be removed in the resource adequacy simulation after adding the deliverable resources, while holding total unserved energy constant. [56]

Figure 17: Transmission Headroom from Potential Retirements for New Resources
Deliverability Study vs. MRI Approach – East/Central Long Island Example

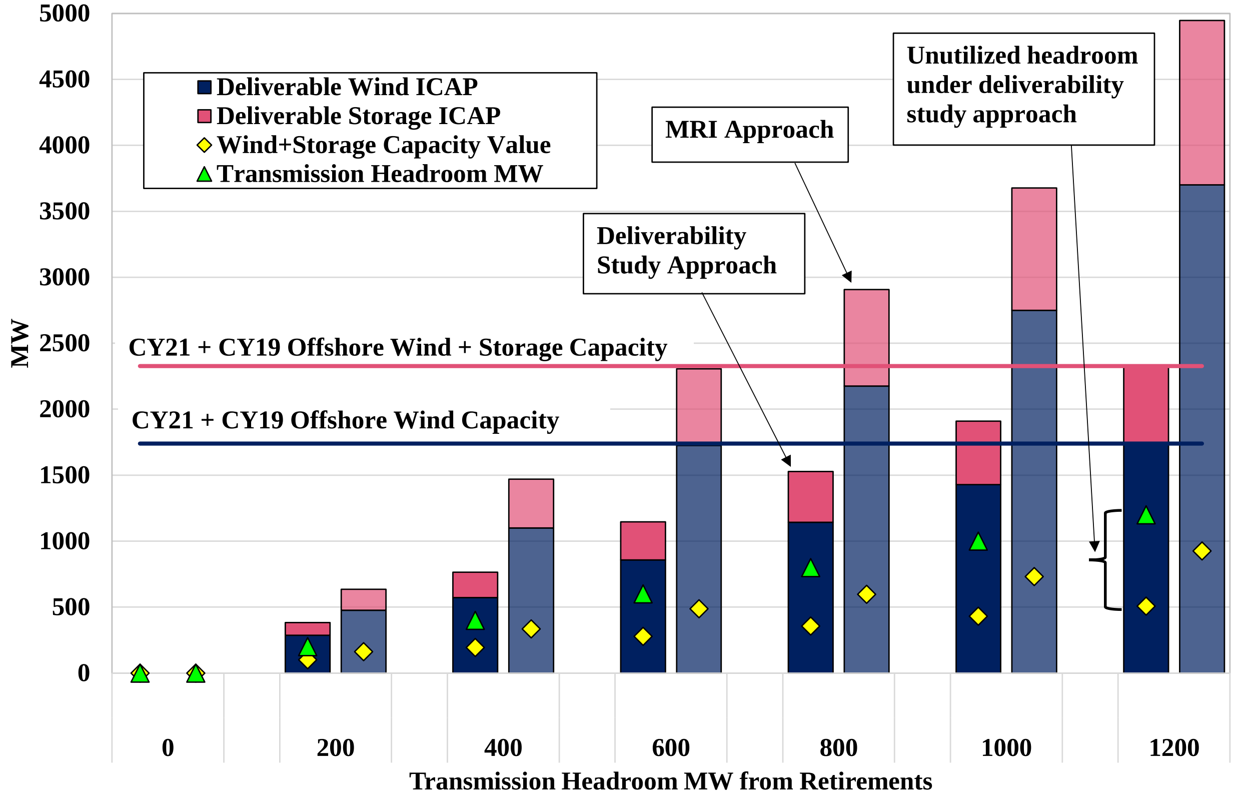


Figure 17 shows that retirements that create transmission headroom make a smaller amount of wind and storage capacity deliverable under the UCDF method than under a probabilistic MRI approach. This is because the UCDF method overestimates offshore wind output in critical hours and does not consider the complementarity between offshore wind and energy storage. The 2.3 GW of offshore wind and energy storage in eastern/central Long Island that participated in the last two Class Year studies would require 1,200 MW of transmission headroom under the UCDF approach, but they are made deliverable by just 600 MW of headroom under the MRI approach. Adjusting the UCDF values over time under the updated procedure will provide only a minor improvement in deliverability because of the misalignment of the hours used in the UCDF with the timing of critical hours shown in Figure 16.

56 We calculate the amount of conventional UCAP that can be displaced by the wind and storage resources as the headroom shown in Figure 17 (represented in the resource adequacy model by a removal of perfect capacity in east and central Long Island), plus or minus additional perfect capacity that must be added or removed in Long Island so that the system remains at the target level of reliability. This is not equivalent to the marginal accredited value these resources would receive in the capacity market. It effectively represents the average capacity value of the resources added to eastern and central Long Island.

This analysis also shows that a portfolio of offshore wind and storage resources requires more substantially more headroom under the UCDF approach (green triangles) than the capacity value it provides (yellow diamonds). For example, retirement of 1,200 MW of UCAP in eastern and central Long Island would provide deliverability headroom for 2.3 GW of offshore wind and solar ICAP, but these resources would provide capacity benefit equivalent to approximately just 500 MW of conventional UCAP. This implies that under the deliverability study approach: (1) if deliverability headroom is provided by construction of SDUs, the upgrades will be inefficiently oversized, or (2) if headroom is provided by retirement of existing resources, the new resources that can replace them will provide far less reliability value. By contrast, a probabilistic MRI-based approach more accurately indicates the amount of new resources that can make use of the headroom afforded by retirements.[57]

2. Concerns with Deliverability Framework – Assumptions on Resource Mix

The Class Year SDU Study models deliverability in a particular future year. For example, the CY21 study (developed in 2021 and 2022) modeled conditions in 2026. As a result, outcomes of the SDU Study are sensitive to key assumptions regarding future conditions, including:

- Proposed new resources that obtained CRIS in a prior Class Year study are modeled in service. However, not all projects that complete a Class Year are ultimately built. For example, in the Class Year 2019 deliverability studies, the 500 MW Poseidon HVDC project (which had previously completed Class Year 2015) was modeled in service in Central Long Island and affected the determination of SDUs. This project subsequently dropped out of NYISO's interconnection queue.
- All existing resources are modeled in service unless they have already submitted retirement notices to NYISO or are otherwise treated as firm retirements.[58] Subsequent economic retirement of projects may cause headroom to change in the future. Consequently, a new project might have an incentive to delay entry until after such a retirement occurs to avoid SDUs.
- The updated UCDF procedure relies on the GE-MARS model used in the most recently available IRM study at the time of each deliverability study. Since this model will not include the Class Year projects or other future changes to the resource mix, the hourly weights used to determine UCDF values will be inaccurate. For intermittent technologies with increasing penetration such as offshore wind, this will tend to inflate SDUs.

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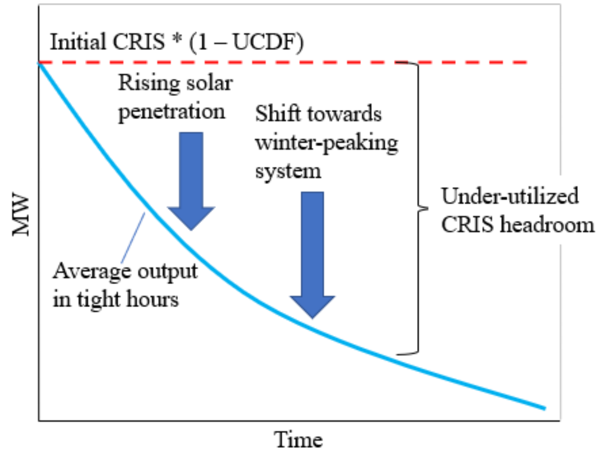
57 This analysis should not be taken as a suggestion that simply using UCDFs derived from MRI results in the current deliverability test would yield accurate results. MRI results will not accurately reflect deliverability constraints unless the relevant transmission bottlenecks are represented in the underlying MARS case. Additionally, MRI results represent an expected improvement in reliability derived from many individual MARS iterations with different conditions, so they are not appropriate for use in a deterministic model. Our recommendations for improving the deliverability framework can be found at the end of this section.

58 Projects that notify NYISO of their intent to transfer their CRIS rights to a Class Year project at the same location will be modeled as retired when the new project is studied.

- The deliverability test currently considers summer peak conditions only. However, winter reliability needs are increasingly important and NYISO may transition to a winter peaking system eventually. CRIS values established through a study that only considers summer conditions may become inaccurate as the system evolves.

As a result, the deliverability study may overestimate or underestimate resources' actual deliverability by the time they are in service and over their useful life. If deliverability is underestimated, developers may be required to pay for upgrades that are ultimately not needed or may need to participate again in subsequent deliverability studies. If deliverability is overestimated (such as if the study includes a future transmission line or retirement which is delayed or canceled), the project may enter service with CRIS rights when it is not actually fully deliverable. This may require the NYISO to increase future locational capacity requirements.

The illustration to the right shows how the deliverability framework might overestimate the headroom needed for a solar resource to be deliverable over the course of its life. The resource's average output during tight hours falls over time due to changes in the system. As a result, the original headroom needed to grant it CRIS rights becomes increasingly excessive.



These problems arise because the deliverability framework requires the NYISO to grant CRIS rights that allow a resource to be treated as fully deliverable in perpetuity, regardless of changes in conditions that might make the project more or less deliverable over time. Hence, the problems with the deliverability framework could be addressed by simply compensating capacity suppliers based on their ability to support system reliability in each year. One way to do this is to define more disaggregated zones that would allow interzonal deliverability constraint to be priced in the capacity market.

3. Concerns with Deliverability Framework – Favors Existing Over New Resources

NYISO's market products are generally designed to provide the same compensation to similarly situated resources, regardless of which resource entered first. This is consistent with well-functioning competitive markets for most products. However, the deliverability rules in the capacity market discriminate in favor of existing resources by imposing SDU on new resources.

For example, recent Class Year Studies have repeatedly included projects seeking CRIS rights on Staten Island that were found to not be deliverable. These projects were allocated SDUs costing hundreds of millions of dollars, which no developer has agreed to pay. However, existing resources in Staten Island earn the New York City capacity price even if bottlenecks prevent their full capacity from being fully delivered to the rest of the zone. This poses a barrier to new resources that effectively prevents them from competing with incumbent resources in export-constrained areas such as Staten Island.[59]

In an efficient market, entry of new capacity to a constrained area would result in a uniform low price for all resources in that area, putting pressure on higher-cost resources to retire. This is the case in NYISO's energy market where entry to a bottlenecked area will reduce LBMPs. This also occurs between zones in the capacity market where surplus capacity in a zone causes its price to fall relative to other zones. However, it is prevented from occurring within capacity zones by the deliverability framework and the lack of granular capacity pricing.

4. Deliverability Framework Conclusions

The NYISO's current rules are poorly suited to address deliverability in the capacity market because: (1) its deterministic deliverability test does not reflect realistic dispatch scenarios; (2) it does not accurately test clean resources such as offshore wind and energy storage, (3) it establishes permanent CRIS rights that do not reflect changes in deliverability as the system changes over time, and (4) it discriminates against new resources in favor of existing resources.

The consequences of these problems are large and growing as recent Class Year studies have allocated prohibitively-costly SDUs to projects seeking CRIS rights, constituting a substantial and inefficient barrier to new investment. To address these concerns, we recommend:

- *Defining a comprehensive set of granular zones in the capacity market*.[60] This would effectively shrink the size of the capacity zones in which new resources seeking CRIS rights would have to be deliverable. This would greatly reduce the number of intrazonal constraints triggering SDUs and allow the capacity market to price many more interzonal constraints. This would improve incentives for both new and existing resources.
- *Implementing locational marginal pricing of capacity ("C-LMP")*. This would establish price signals based on the probabilistic marginal reliability impact (MRI) at a wider range of locations.[61] Resources would not be obligated to pay for upgrades to sell capacity, but would earn a capacity price based on the marginal value of capacity at their location. This would require the definition of more granular capacity zones as described above, but would allow for more efficient pricing than is possible under the current market.

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[59] Projects may avoid a deliverability study or reduce the exposure to SDUs by acquiring the CRIS rights of an existing resource. NYISO proposed changes to its CRIS transfer rules to make this process more flexible. This may help facilitate the entry and exit, but will not resolve the discriminatory nature of the deliverability rules. Holders of existing CRIS rights will value them based on their ongoing capacity profits even when it is efficient to retire so new resource allocated a costly SDU will continue to face inefficient barriers to entry. See Jan. 25, 2023 presentation to Management Committee "CRIS Expiration Evaluation", available here.

[60] See Recommendation 2022-4 in Section XII and Section VIII.D.

[61] See Recommendation 2013-1c in Section XII and Section VIII.E.

- *Establishing financial capacity transfer rights (FCTRs)* to be allocated to developers or others that wish to pay for network upgrades that would alleviate interzonal transmission bottlenecks. This would allow market participants who pay for upgrades retain the economic value of those upgrades in the capacity market,[62] as will as providing a hedge against the risk of binding transmission constraints in the capacity market.[63]

B. Evaluation of NYISO's Transmission Planning Processes

NYISO's centralized transmission planning processes are designed to identify and fund transmission investments that are most cost-effective for satisfying reliability needs, achieving public policy goals, and/or reducing congestion. These planning processes are important because the wholesale markets generally do not provide efficient incentives for merchant transmission investment. Projects selected in the planning processes are funded through regulated cost recovery rather than market revenues. Selecting inefficient projects can result in excessive ratepayer costs and crowd out merchant solutions (transmission and non-transmission) that would otherwise achieve similar objectives more efficiently. Hence, transmission planning processes should be designed to select the most efficient projects by utilizing rigorous cost-benefit analyses. Such analyses should quantify project benefits considering the value of wholesale market services including capacity, energy, and ancillary services. This subsection provides an overview of NYISO's bulk transmission planning processes and summarizes improvements that will result in more efficient transmission procurements.

1. Overview of NYISO's Transmission Planning Process

NYISO performs centralized transmission planning through the Comprehensive System Planning process (CSPP).[64] The CSPP consists of the following processes:

- The *Reliability Planning Process* identifies reliability needs in the short and long term and soliciting solutions for needs for Bulk Power Transmission Facilities ("BPTFs");
- The *Economic Planning Process* studies potential future congestion on the transmission system. It includes a phase to evaluate projects proposed by developers to relieve congestion, but no transmission has ever been built through this process. The main product of the Economic Planning Process is the System & Resource Outlook ("the Outlook").[65] The Outlook is a recurring study that considers future system congestion and is used as the basis for evaluations of projects in other processes, such as the PPTPP.

62 See Recommendation 2012-1c in Section XII and Section VIII.H.

63 For example, consider an investor that owns a generator in an export-constrained zone and FCTRs on the interface between that zone and another zone. When the zone is export-constrained, capacity payments to generators in the zone would fall but payments to the holders of FCTRs would rise.

64 For more information about the CSPP, see here.

65 The initial 2021 Outlook study (formerly known as the CARIS) was completed in 2022 and is available here.

- The *Public Policy Transmission Planning Process (PPTPP)* solicits, evaluates and selects projects designed to address policy-driven needs identified by the NY State Public Service Commission, such as integration of renewable energy.

In addition to these NYISO planning mechanisms, transmission planning carried out by utilities and state agencies has impacts on the wholesale markets. New York's electric utilities have recently proposed a comprehensive process to plan investments in lower-voltage local transmission and distribution that are needed to accommodate clean energy goals.[66] The state also has a process to identify "Priority Transmission Projects" regarded as needing rapid approval to comply with state policy mandates, to be built by the New York Power Authority.[67] In recent years, NYISO transmission planning has primarily taken place through the PPTPP. NYISO has evaluated solutions for two Public Policy Transmission Needs ("PPTN"): the Western New York PPTN and the AC Transmission PPTN. 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. The NYISO is currently evaluating proposals to address this PPTN and is expected to recommend a project to NYISO's Board of Directors in 2023-Q2.[68]

2. Improvements to Transmission Planning Processes

Transmission planning has major impacts on prices and incentives in the NYISO markets. Efficient planning decisions can enable investment in low-cost generation resources and reduce the amount of capacity needed in higher cost areas. However, inefficient planning decisions can undermine market incentives to invest in non-transmission projects that provide similar benefits at lower cost. For example, a large transmission project designed to reduce curtailment of renewable energy may be much more costly than a smaller transmission project paired with additional renewable and storage investment, even if both yield comparable benefits. This subsection discusses how NYISO's transmission planning can be made more efficient using wholesale market principles.

Inclusion of Market Incentives in Planning Models

Assumptions used in long-term planning models such as NYISO's Outlook affect the location and magnitude of apparent transmission needs. In particular, planning studies must make assumptions about new generation, storage and retirements in the future. NYISO's 2021 Outlook improved on earlier economic planning studies by using a capacity expansion model to develop a forecast of future resource mix changes needed to comply with state clean energy

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

67 For example, see October 15, 2020 Order in NYPSC Case 20-E-0197, identifying the "Northern New York" bulk transmission project as a Priority Transmission Project.

68 See postings related to "LI PPTN" in NYISO's Electric System Planning Working Group, available here.

mandates.[69] In general, this approach is consistent with the expectation that NYISO market incentives will encourage investment in resources that efficiently contribute to state mandates. However, limitations of the capacity expansion model resulted in a forecasted resource mix with significant overinvestment in some technologies and locations and underinvestment in others.

Figure 18 shows the Implied Net REC (INREC) cost of various technologies in the Outlook.[70] We define the INREC cost as the net cost of incremental renewable energy output resulting from an investment in generation, storage, or transmission.[71] Efficient should cause INREC costs to converge as investment would shift from more costly clean resources to less costly ones. The bars indicate the range of INREC costs for each technology across locations.

Figure 18: Implied Net REC Cost by Technology in 2021 Outlook "S2" Case

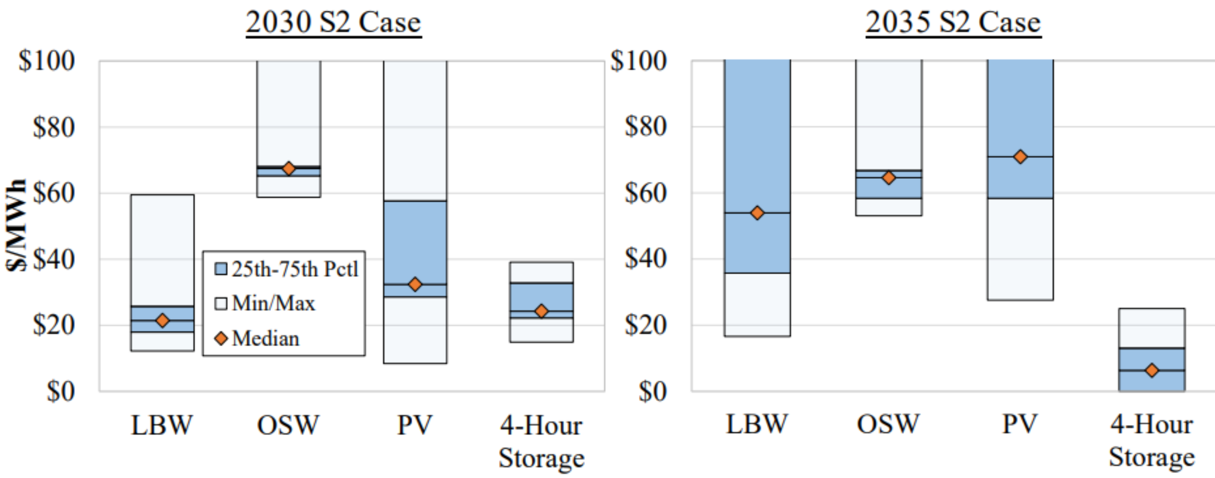

Figure 18 shows that INREC costs vary widely within and between technology types in the Outlook. This suggests that (1) some renewable projects were assumed to be built at inefficient locations (largely due to transmission constraints), and (2) the assumed level of investment in storage is inefficiently low in the long term. This is likely to increase the apparent benefits of transmission expansion. Failing to account for the incentives of developers participating in state solicitations to pursue more competitive locations and technologies will likely result in an inaccurate forecast of future transmission needs.

It is also important to consider how transmission projects will impact market incentives when evaluating individual projects. Generation and storage developers are likely to adapt their plans following selection of a major transmission project, and realistic evaluation of the project's

69 For more detail, see MMU Review of 2021-2040 System & Resource Outlook, August 2022, available here.

70 A capacity expansion model develops a forecast of generation investments based on economics, and it can be designed to include requirements such as meeting state renewable energy targets.

71 The Implied Net REC Cost equals the average REC payment that a project would need to be economic in $/MWh of renewable energy that it can deliver without causing curtailment of other resources to increase.

benefits requires one to account for this. Recent NYISO evaluations have considered how projects will affect other investments in the system only to a limited degree. As a result, some types of benefits are undervalued while others are overvalued, which cause NYISO to not select the most efficient project.

Valuation of Transmission Projects Using Wholesale Market Prices

Transmission projects' benefits should be evaluated in a way that is consistent with the revenue that a non-regulated resource providing comparable benefits would receive in the NYISO markets. Such an approach would help to make clear when a regulated or non-regulated project would be more cost-effective. It would also support selection of the most efficiently-sized transmission projects by considering the marginal value of their benefits. By contrast, recent solicitations have been evaluated using methods that do not correspond to how the project's benefits would be valued in the NYISO markets, making it challenging to assess which projects are most competitive. Examples of how major transmission benefits can be calculated consistently with market prices are as follows:[72]

- Energy benefits – The market value of the congestion relief provided by the project. This is calculated considering the project's impact on constrained transmission elements in each hour (which may or may not be project facilities), given the flows and the shadow prices of congested elements.
- Capacity benefits – The market value of avoided generation investment that would be needed without the project. This is calculated using the marginal reliability impact ("MRI") of the project facilities, the increase in transfer capability they provide, and the Net Cost of New Entry ("Net CONE") used to determine capacity prices. This results in valuation comparable to a capacity market participant.
- Implied Net REC – For solicitations that explicitly target renewable energy integration, the efficiency of transmission proposals can be compared to other alternatives by calculating an Implied Net REC. This is calculated as the project's levelized cost net of energy and capacity benefits, divided by the incremental reduction in annual renewable curtailment it provides ("renewable deliverability impact").[73]

Transmission Planning Conclusions

Using the principles of efficient market incentives in planning models and when evaluating proposed projects will allow the NYISO to select more efficient projects and help to level the

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72 See also February 21, 2023 comments of Potomac Economics in NYPSC Case 22-E-0633.

73 For renewable and storage projects, the renewable deliverability impact is the annual MWh of energy an incremental MW of the resource would provide (or save from being curtailed) without causing curtailment of other resources. For transmission projects, the renewable deliverability impact is the annual MWh of incremental transfers of renewable energy across the project facilities and other lines whose loading the project relieves, measured during hours of curtailment due to transmission constraints. This can be calculated using generation shift factors of renewable resources and flows over the project facilities.

playing field between regulated transmission and non-regulated investments. Hence, we recommend the following:[74]

a) Update the methodology of the Outlook study to better account for market incentives of renewable and storage resources. When storage is a lower-cost means to manage excess renewable output, such storage should be modeled to avoid inflated transmission benefits.

b) Evaluate economic and PPTN projects using a project case that considers changes to the resource mix resulting from the Project's inclusion; and

c) Estimate transmission project benefits based on their NYISO market value.

74 See Recommendation 2022-3 in Section XII.

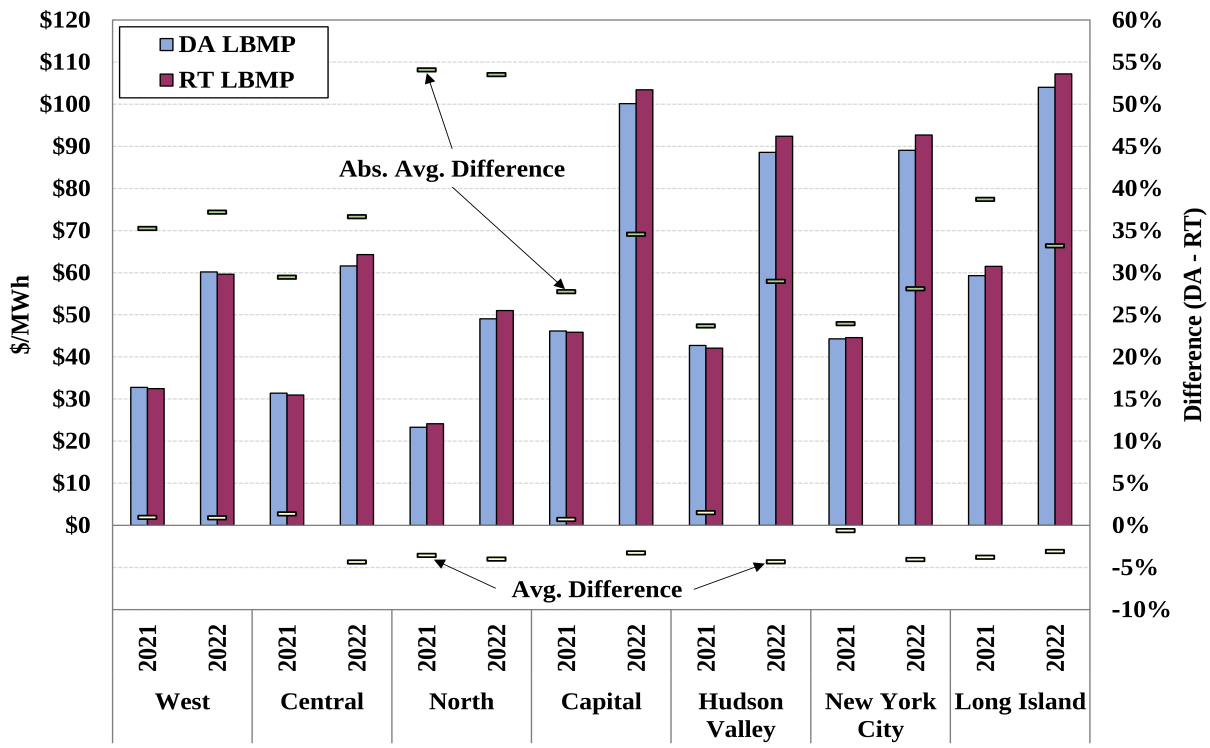
V. DAY-AHEAD MARKET PERFORMANCE

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 figure 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.[75] These statistics are shown on an annual basis.

Figure 19: Price Convergence between Day-Ahead and Real-Time Markets
Select Zones, 2021 - 2022



75 Section I.H in the Appendix evaluates the monthly variations of average day-ahead and real-time energy.

Day-ahead prices in 2022 were significantly lower on average than real-time prices in all regions except for the West Zone. Real-time prices displayed the largest premiums over day-ahead prices in periods of gas price volatility and summer peak load conditions, while the shoulder months saw small day-ahead price premiums. We also observed:

- Real-time price volatility spiked during peak summer and winter periods, and the magnitude and frequency of generator outages and deratings rose under high load levels.[76]
- Real-time prices were especially volatile during the December cold spell and other cold weather. Import transactions were often scheduled by RTC and subsequently cut by the neighboring control area during cold conditions, resulting in larger price effects. Furthermore, generation availability was reduced by lack of fuel and more frequent outages related to cold weather and secondary fuel operations.[77]
- Transfer capability, especially on the Central East Interface, was reduced for much of the year due to extended transmission outages to support the Public Policy Part A and B projects. The outages contributed to more frequent and volatile congestion.

The average absolute difference indicates that the highest volatility was in the North zone. Additionally, the other Upstate regions (Zones A-F) and Long Island saw greater volatility than the Hudson Valley and New York City regions.

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.

Capital zone prices were more volatile in 2022 because: (a) transmission outages increased congestion on flows from the central part of the state and (b) volatile loop flows from New England.

Central zone experienced more volatility, due partly to renewable capacity additions upstream of key transmission bottlenecks that tended to schedule less in the day-ahead market than their forecasted output. Increased congestion driven by wind capacity in constrained areas of the Central zone highlights the potential benefits of energy storage additions.

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

76 See discussion in Section X.A.

77 See discussion in Section II.G.

of physical load, virtual trades, and virtual imports and exports as a percent of real-time load in 2021 and 2022 for several regions.[78]

Overall, net scheduled load in the day-ahead market was approximately 97 percent of actual NYCA load during daily peak load hours in 2022, up one percent from 2021. 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 in some areas.

Table 3: Day-Ahead Load Scheduling versus Actual Load

By Region, During Daily Peak Load Hours, 2021 – 2022

Region	Year	Bilateral + Fixed Load	Price-Capped Load	Virtual Supply	Virtual Load	Virtual Import	Virtual Export	Net Scheduled Load
West	2021	98.1%	0.0%	-4.4%	15.4%			109.2%
	2022	98.7%	0.0%	-5.7%	11.4%			104.3%
Central NY	2021	110.5%	0.0%	-21.0%	4.7%			94.2%
	2022	95.1%	0.0%	-5.6%	5.8%			95.3%
North	2021	80.8%	0.0%	-18.0%	7.0%			69.9%
	2022	88.5%	0.2%	-11.7%	10.7%			87.6%
Capital	2021	94.8%	0.0%	-5.7%	7.0%			96.1%
	2022	94.4%	0.0%	-5.3%	6.9%			96.0%
Lower Hudson	2021	73.7%	22.8%	-17.0%	12.5%			92.1%
	2022	72.7%	23.6%	-13.7%	12.6%			95.1%
New York City	2021	66.9%	30.8%	-1.5%	4.3%			100.5%
	2022	64.6%	32.9%	-1.4%	2.8%			99.0%
Long Island	2021	93.5%	0.0%	-1.7%	9.0%			100.9%
	2022	98.0%	0.0%	-1.7%	7.9%			104.2%
NYCA	2021	86.2%	12.7%	-8.6%	7.4%	-2.9%	0.8%	95.6%
	2022	82.9%	13.6%	-4.9%	6.7%	-2.5%	0.7%	96.6%

Average net load scheduling tends to be higher where volatile real-time congestion leads to very high (rather than low) real-time prices. Historically, this was the case in the West zone where net load scheduling was high because the majority of load was located just downstream of transmission bottlenecks near Niagara. However, completion of the Empire State Public Policy transmission line in June 2022 has relieved most of this congestion and the related real-time

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

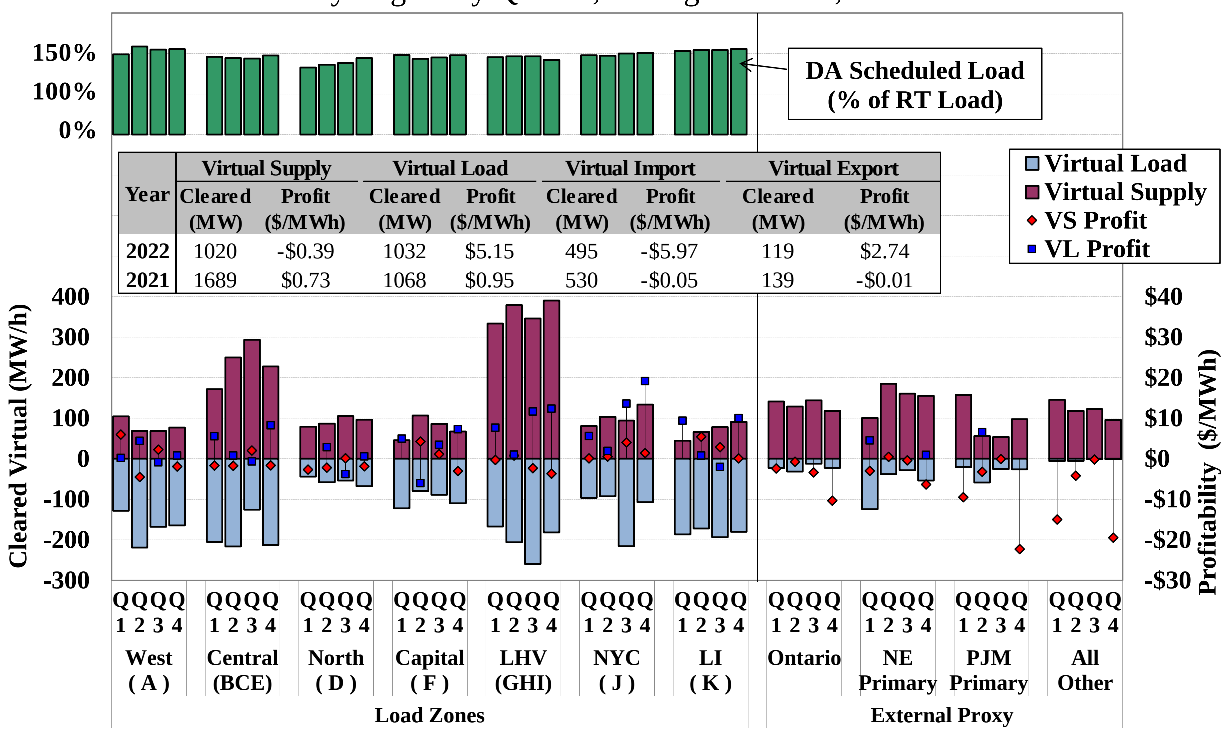
price volatility. Consequently, average day-ahead net scheduled load in the West zone fell by 5 percent from 2021 to 2022.

Most regions exhibited higher day-ahead net load scheduling consistent with higher and more volatile real-time energy prices in 2022. Regions such as Long Island and the Hudson Valley saw roughly 3 percent increases from the prior year levels. Higher day-ahead net load scheduling generally helps increase commitment of resources in these areas. One area where day-ahead load scheduling did not increase from the prior year despite higher real-time price conditions was the Capital Zone.

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 20 summarizes virtual trading by location in 2022, including internal zones and external interfaces.[79]

Figure 20: Virtual Trading Activity
by Region by Quarter, During All Hours, 2022



Year	Virtual Supply Cleared (MW)	Virtual Supply Profit ($/MWh)	Virtual Load Cleared (MW)	Virtual Load Profit ($/MWh)	Virtual Import Cleared (MW)	Virtual Import Profit ($/MWh)	Virtual Export Cleared (MW)	Virtual Export Profit ($/MWh)
2022	1020	-$0.39	1032	$5.15	495	-$5.97	119	$2.74
2021	1689	$0.73	1068	$0.95	530	-$0.05	139	-$0.01

79 See Figure A-53 in the Appendix for a detailed description of the chart.

Virtual trading patterns were consistent from 2021 to 2022 except in Central zone where virtual supply decreased sharply in the third quarter of 2021 due to changes in bilateral contracts. The general increase in net virtual load was encouraged by higher real-time price volatility in 2022.

The profits and losses of virtual load and supply has varied over time, reflecting the difficulty of predicting volatile real-time prices. Nonetheless, virtual traders netted a gross profit of approximately $20 million in 2022, reflecting that they have generally improved convergence between day-ahead and real-time prices. The average rate of gross virtual profitability remained relatively low at $0.86 per MWh. In general, low virtual profitability indicates that the markets are relatively well-arbitraged and is consistent with an efficient day-ahead market.

VI. 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 seven 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
- Operation 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 XII provides a comprehensive list of our recommendations.

A. Market Performance under Shortage Conditions

Prices during shortages are an important contributor to efficient long-term price signals. Shortages occur when resources are insufficient to meet the system's need for energy and ancillary services. Efficient shortage prices reward suppliers and demand response resources for responding to shortages. This ultimately improves the resource mix by shifting revenues from the capacity market into the energy market in a manner the reflects the resources' performance. In this subsection, we evaluate the real-time market operations and prices when the system is in the following two types of shortage conditions:[80]

80 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 2022.

- *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.

1. Operating Reserve and Regulation Shortages

In 2022, there were more frequent occurrences of operating reserve and regulation shortages compared to 2021. The increases reflected more hours of tight operating conditions and higher energy prices, which increased the opportunity cost of providing ancillary services. Regulation shortages continued to be the most frequent type of ancillary services shortage, occurring in 9.7 percent of intervals in 2022, which was a significant increase from the 3.1 percent observed in 2021. Small regulation shortages were common when the system was ramp-limited because the lowest step of the regulation demand curve is $25/MW. Operating reserve shortages were relatively infrequent in 2022, with the most frequent being systemwide 30-minute reserve shortages, occurring in 0.8 percent of intervals.

Shortages of regulation and operating reserves collectively increased average LBMPs by 8 to 14 percent in 2022.[81] Therefore, ancillary services shortages have a significant impact on investment signals, shifting incentives toward generation with flexible operating characteristics. In this report, we identify three issues with market performance related to reserve scheduling and reserve shortage conditions that are discussed below.

Need for Dynamic Reserve Requirements

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:[82]

- Eastern New York given flows over the Central-East Interface.
- Southeast New York given flows over the UPNY-SENY interface.
- Long Island given transmission constraints that may limit the amount of reserves that can be deployed there in response to a contingency outside Long Island.
- NYCA given imports across the HVDC connection with Quebec;

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

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

- NYCA given that day-ahead scheduled load is sometimes less than forecasted load and that some supply resources in the day-ahead market do not contribute to satisfying forecasted operational requirements (e.g., virtual supply). In 2022, physical energy was under-scheduled by an hourly average of 600 MW;[83] and
- 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 99 percent of intervals in 2022 when New York City had either 10-minute or 30-minute shortages.[84] Therefore, dynamic reserve requirements are needed to schedule resources more efficiently in the pocket.

The NYISO's *Dynamic Reserves* market project and several planned follow-on projects are expected to address the six areas mentioned above.[85]

Operating Reserve Demand Curve Price Levels

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 21 examines the shortage pricing incentives that will be provided by NYISO compared to its neighbors with PFP rules.[86] 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.[87] 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.
- In PJM, the Performance Rate is set to be approximately $3,400 per MWh in addition to real-time shortage pricing of $850 per MWh for each of its reserve requirements, capped at $850 for a 30-minute shortage, $1,275 for a ten-minute shortage and $1700 for a

83 See Figure A-107 in the Appendix for this analysis.

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

85 See 2022 Master Plan projects *Dynamic Reserves*, *More Granular Operating Reserves*, and *Long Island Reserve Pricing* with planned implementation all in 2026. Also see *Reserve Requirements Postings and LBMP Formation with Dynamic Reserves*, presented to the MIWG on March 31, 2023, slides 10-16 discussing the use of forecast load in the formulation.

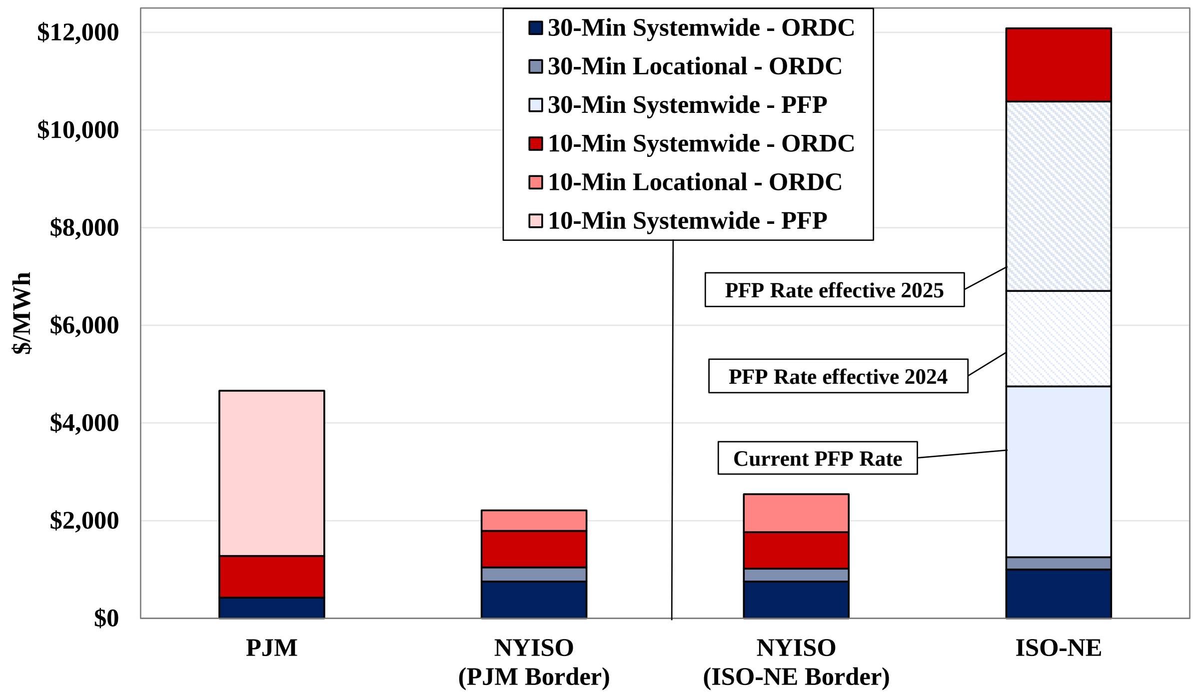
86 See Figure A-100 in the Appendix for description of this chart.

87 See ISO New England Tariff Section III.13.7.2.

synchronous reserve shortage. This will provide incentives of approximately $4,675 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 30-minute reserve shortages, NYISO invokes statewide shortage pricing of up to $750/MWh. During deep shortages of multiple 30-minute and 10-minute reserve requirements, NYISO invokes statewide shortage pricing levels that can exceed $2,000/MWh under very severe conditions. Figure 21 compares shortage pricing levels in PJM and ISO-NE with NYISO including adders for locational reserve requirements near each border.

Figure 21: 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 ISO-NE uses over $4,500 per MWh during slight 30-minute reserve shortages. This disparity will increase significantly in the coming years for modest and deep reserve shortages. Hence, when NYISO is in a much less reliable state than PJM or ISO-NE, market participants will have strong incentives to export power from (or reduce imports to) NYISO. This disparity will either undermine reliability in New York or require NYISO operators to engage in out-of-market actions to maintain reliability.

Our 2018 State of the Market report found that weak market incentives on the NYISO side led to OOM actions by NYISO in the first-ever PFP event in the ISO-NE market.[88] If NYISO reserve demand curves provided stronger incentives, these OOM actions would not have been necessary.

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

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.[89]

Shortages Resulting from Import Curtailments

Third, in recent years, a key driver of operating reserve shortages has been curtailments and cuts of scheduled imports close to real-time. Ordinarily, firms schedule power to flow between control areas by scheduling an export from one area and an import into a neighboring area. To schedule real-time imports to NYISO, firms submit an import offer to NYISO up to 75 minutes ahead of the scheduling hour and an export bid in the source area in accordance with its bidding timeline. RTC determines whether to schedule hourly imports 45 minutes before the hour begins, while 15-minute imports are scheduled (or not) 15 minutes before each 15-minute period begins. RTC also determines start-up and shut-down instructions for 10-minute and 30-minute peaking units 15 to 30 minutes before each 15-minute period begins, so RTC often foregoes scheduling a peaking unit when a lower-cost import is available. Consequently, if RTC foregoes scheduling a peaking unit because a low-cost import is available, but the low-cost import is subsequently cut by the scheduling process in the neighboring control area, RTD will require more expensive resources to maintain reliability in the 5-minute dispatch time frame.

In 2022, substantial quantities of external transactions were scheduled by RTC but subsequently cut or curtailed. This includes roughly:

- 640 hours when an average of 160 MW of imports were cut from Ontario, primarily because imports to NYISO are often submitted as price-sensitive export bids on the Ontario side and cut in Ontario's economic evaluation. This includes direct imports from Ontario to NYISO and wheels through Quebec to NYISO.
- 80 hours when an average of 200 MW of imports were cut from Quebec, primarily because TransEnergie did not identify transmission bottlenecks within its footprint until after the transactions were scheduled by RTC.
- 150 hours when an average of 290 MW of imports were cut from PJM, mainly due to TLR curtailments in January and capacity deficiency related curtailments in December.

89 See Recommendation #2017-2 in Section XII.

- 35 hours when an average of 270 MW of imports were cut from New England, primarily because ISO-NE identified potential capacity deficiencies after the transactions were scheduled by RTC.

For its part, NYISO cut or curtailed an average of 240 MW of imports and/or exports in a total of 170 hours, primarily to manage internal transmission security constraints on facilities not secured in the day-ahead and real-time market models.

As we discuss in Section II.G of this report, import cuts by PJM and Ontario were a major driver of reserve shortages on December 23 and 24, 2022. Many of the reserve shortages occurred when RTC scheduled low-cost imports from PJM and Ontario, leading RTC to shut-down higher-cost peaking units. After the peaking units were instructed to shut down, the imports were cut by neighboring areas, leading to reserve shortage conditions in NYISO. We are evaluating potential modifications to the scheduling process to reduce the inefficiencies that can result from transaction cuts and curtailments.

2. 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 2022, transmission shortages occurred in nearly 14 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.[90] Constraint relaxation was relatively infrequent in 2022, occurring in just 5 percent of all transmission shortages.[91]

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 each facility. The GTDC has a 5-MW step and a 15-MW step for a total of 20 MW where redispatch costs are limited. Since the GTDC is always 20-MW long, it is overly conservative for a large facility with a 50-MW CRM and too slack for a small facility with a 10-MW CRM.[92]

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90 A CRM value of 10 MW is used for 69 kV and 115 kV constraints, while a default CRM value of 20 MW is used for most facilities at higher voltage levels.

91 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-101 .

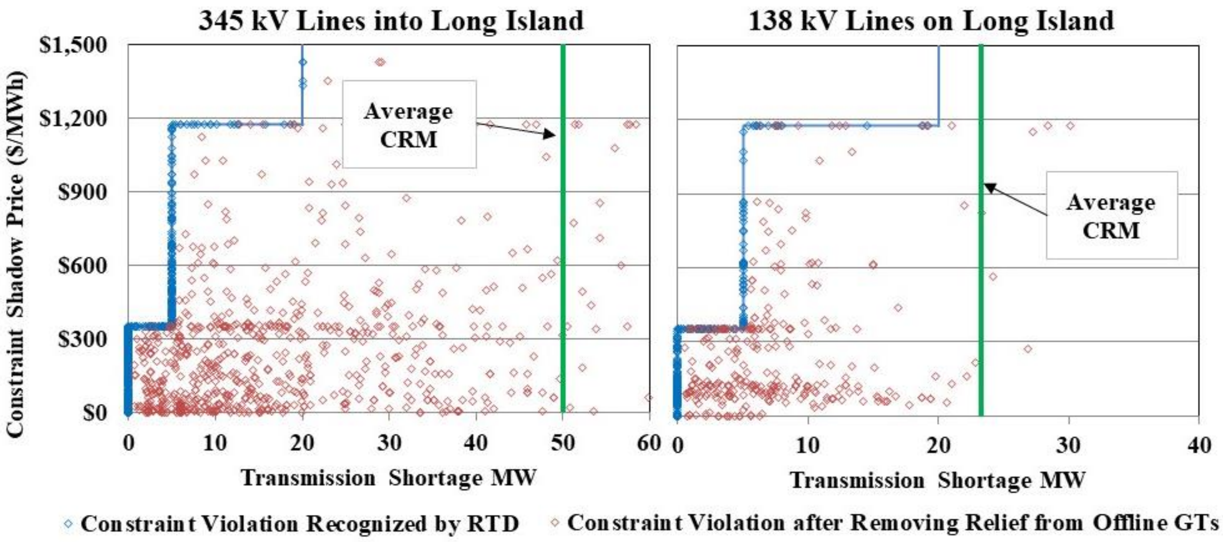
92 See Table A-14 in the Appendix for a more detailed description.

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.[93] The NYISO plans to implement *Constraint Specific Transmission Shortage Pricing* in the fourth quarter of 2023, which is expected to be a significant improvement over the current GTDC because:[94]

- The proposed GTDC will increase more gradually than the current GTDC, which will reduce unnecessary price volatility.
- The MW-range of the proposed GTDC will be based on the CRM of the constraint, which will be a significant improvement over the current GTDC, which uses a 20-MW range regardless of the CRM value.
- The proposed GTDC will extend to internal facilities that are currently assigned a zero value CRM, which will reduce the occurrences of constraint relaxation.

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 22 shows our analysis of the 345 kV and 138 kV facilities on Long Island.[95]

Figure 22: Transmission Constraint Shadow Prices and Violations
With and Without "Relief" from Offline GTs, 2022



93 Recommendation #2015-17 in Section XII.

94 See "Constraint Specific Transmission Shortage Pricing", at August 26, 2021 ICAPWG/MIWG meeting.

95 See Figure A-102 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.[96]

B. Efficiency of Gas Turbine Commitments

It is important to evaluate the efficiency of gas turbine commitment in the real-time market. Over-commitment can result in depressed real-time prices and higher uplift costs, while under-commitment may lead to unnecessary price spikes. Gas turbines are usually started during tight operating conditions, making it crucial to establish efficient real-time prices that reward flexible generators. 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 the efficiency of economic GT commitments in the past three years, 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.[97] In general, lower percentage numbers indicate more efficient of scheduling and pricing. The total production costs of all economic GT starts that were not recouped through LBMP revenues was roughly 15 percent in 2022, comparable to the level seen in 2021.

Table 4: Efficiency of Economic Gas Turbine Commitment
2020 - 2022

Startup Performance	Cost not Covered by LBMP Revenues		
	2020	**2021**	**2022**
< 80%	28%	17%	19%
>= 80%	21%	14%	14%
Total	**22%**	**14%**	**15%**

96 See Recommendation #2020-2.

97 Economic GT commitments include GT start-ups made economically by RTC, RTD, and RTD-CAM, excluding self-schedules. See Figure A-87 in the Appendix for more details of this analysis.

The improvement from 2020 to 2021 and 2022 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.

While the modest decline in efficiency from 2021 to 2022 was driven by several factors:

- Divergence between RTC and RTD, which may lead an economic RTC-committed GT to be uneconomic in RTD, became worse in 2022. This was caused by larger load forecast errors, more frequent interchange curtailments, and increased volatility of loop flows at the NY/NE border that influenced congestion patterns.[98]
- The start-up performance of some fast-start units was worse.[99] 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. 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.

The market should provide incentives for firms to maintain and operate their generators reliably in accordance with ISO instructions. Thus, it is appropriate that 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 revenues from the sale of operating reserves. 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 because 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). Hence, the current BPCG rules tend to mute the incentive to perform reliably. It would be beneficial to consider changes in BPCG rules to provide better incentives for performance.

C. Dispatch Performance of Duct-Firing Capacity

Most combined cycle units in New York have a duct burner, which uses supplemental 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

[98] See Section IV.D of the Appendix for analysis of divergence between RTC and RTD.

[99] See Section V.B of the Appendix for analysis of GT start-up performance.

energy market as a portion of the dispatchable range of the unit. There are a total of 44 units across the state that are capable of providing 886 MW of duct-firing capacity in the summer and 917 such MW in the winter, collectively.[100] 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.[101] However, this duct burner capacity is treated as capable of following 5-minute dispatch signals in the market scheduling and pricing software. Given that inconsistency between the physical capability of the duct firing capacity and the treatment of it in the scheduling and pricing software, we estimate that, in 2022, on average: [102]

- 120 MW was offered but not capable of following 5-minute ramping instructions;
- 111 MW was scheduled for but not capable of providing 10-minute reserves; and
- 18 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 63 MW of duct-firing capacity was unavailable for this reason in 2022.[103]
- 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.[104]
- 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

100 See Table A-9 in the Appendix.

101 See Figure A-88 in the Appendix.

102 See Figure A-89 in the Appendix.

103 See Figure A-89 in the Appendix.

104 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.

dispatch. When units face the risk of providing operating reserves in the duct-firing 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. Additionally, some units were disqualified from offering reserves because they were not able to perform in audits of the duct burner range. We estimate that an average of 54 MW of available 10-minute and 30-minute reserves from baseload capacity (i.e., non-duct ranges) were not offered for this reason in 2022.[105]

We recommend NYISO consider alternative ways to schedule this capacity that takes into account the physical limitations of duct burners.[106] Ideally, this would: (a) allow generators to submit offers that reflect their true ramp capabilities in both baseload portion and duct-firing portion, so that energy and reserves could be scheduled appropriately and efficiently, and (b) 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.[107] The project's target deliverables includes a Market Design Complete in 2024 and a Market Design Deployment in 2025.[108]

D. 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.[109] 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.

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105 See Figure A-89 in the Appendix.

106 See Recommendation #2020-1.

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

108 See 2022 Master Plan, November 2022.

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

In 2022, 73 percent (or $51 million) of real-time congestion in New York City occurred on N-1 transmission constraints that would have been loaded above LTE after a single contingency. As shown in Table 5, the additional transfer capability above LTE on New York City transmission facilities averaged approximately: (a) 15 to 65 MW (or 7 to 29 percent of individual LTE ratings) for 138 kV load-pockets; and (b) 180 to 365 MW (or 24 to 44 percent of individual LTE ratings) for the 345 kV system during congested real-time intervals in 2022.[110]

Table 5: Modeled Limits vs Seasonal Limits for Select New York City N-1 Constraints
In the Real-Time Market, 2022

Transmission Facility		Average Constraint Limit (MW)		
		N-1 Limit Used	Seasonal LTE	Seasonal STE
345 kV	Goethals-Gowanus	917	739	1235
	Motthavn-Dunwodie	1047	842	1302
	Motthavn-Rainey	1199	833	1298
	Farragut-Gowanus	1126	898	1355
138 kV	Greenwd-Vernon	248	232	263
	Foxhills-Greenwd	309	245	375
	Kentave-Vernon	258	237	277

Although these increases were largely due to the availability of operating reserves in New York City, reserve providers are not currently compensated for providing such congestion relief. This reduces their incentives to be available in the short term and to invest in flexible resources in the long term. Additionally, the dispatch of reserve capacity by market software can sometimes reduce transfer capability into New York City, making the dispatch of these units inefficient.

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 LBMP, similar to how energy producers are compensated.[111] 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 following the loss of generation after a natural gas supply contingency, such as dual fuel units that can quickly switch from gas to oil.

E. 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 limits. However, transmission lines that are controlled by phase angle regulators ("PAR") have the potential to

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

111 See Recommendation #2016-1.

provide greater benefits than non-controllable AC transmission lines. PAR-controlled lines can be secured without the need for generator redispatch, and PAR-controlled lines can be adjusted to manage other transmission facilities, which can help to minimize costs and improve the efficiency of the power system. PAR-controlled lines are modeled in the market software in one of two ways:

- "Optimized" PAR-controlled lines are normally modeled as reducing 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 2022. 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[112, 113]
2022

	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					-15	$13.35	52%	$0.1
New England to NYCA								
Sand Bar	-72	-$35.74	90%	$22	0.1	-$32.91	55%	$0.8
PJM to NYCA								
Waldwick	64	$14.90	62%	$22	-33	$14.28	48%	-$12
Ramapo	289	$18.76	83%	$77	199	$18.58	73%	$30
Goethals	34	$16.93	65%	$12	114	$12.83	70%	$10
Long Island to NYC								
Lake Success	129	-$9.77	3%	-$13	-1	-$10.21	46%	-$0.1
Valley Stream	92	-$10.08	4%	-$9	0.4	-$11.18	41%	-$0.2

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 300 MW from upstate to

112 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.

113 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.

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 2022. This is primarily because prices on Long Island were typically higher than those in New York City where the 901 and 903 lines connect at the Jamaica bus. Real-time adjustments in flows were generally small relative to day-ahead scheduled flows, since these PAR-controlled lines were operated to the same schedule in the day-ahead and real-time markets.

The transfers across the 901 and 903 lines:

- Increased production costs by $22 million in 2022 (and $10 million in 2021).
- 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 455 thousand tons of CO_2 and 607 tons of NOx pollution in non-attainment areas in 2022. Hence, the inefficient operation of these lines accounted for 8 percent of NOx pollution from NYISO power plants in non-attainment areas in 2022.
- 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 the 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. Therefore, it would be highly beneficial to modify the existing contract or find alternative ways under the current contract to operate the lines more efficiently.[114] 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.[115] We recommend the NYISO work with the parties involved in this contract to explore changes that would allow the lines to be used more efficiently.[116]

The PAR-controlled lines between PJM and the NYISO are operated under the M2M JOA with the goal of being responsive to market price signals, although the scheduling efficiency varied among these lines.[117] 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

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114 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.

115 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.

116 See Recommendation #2012-8 in Section XII.

117 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.

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 $111 million in 2022, the impact of their real-time operations was mixed. The J and K lines accounted for a $12 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 $30 million and $10 million, respectively.[118] Section VII 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 15 percent of overall price divergence in 2022.[119] 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.

F. 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 in New York City 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
- ***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

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

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

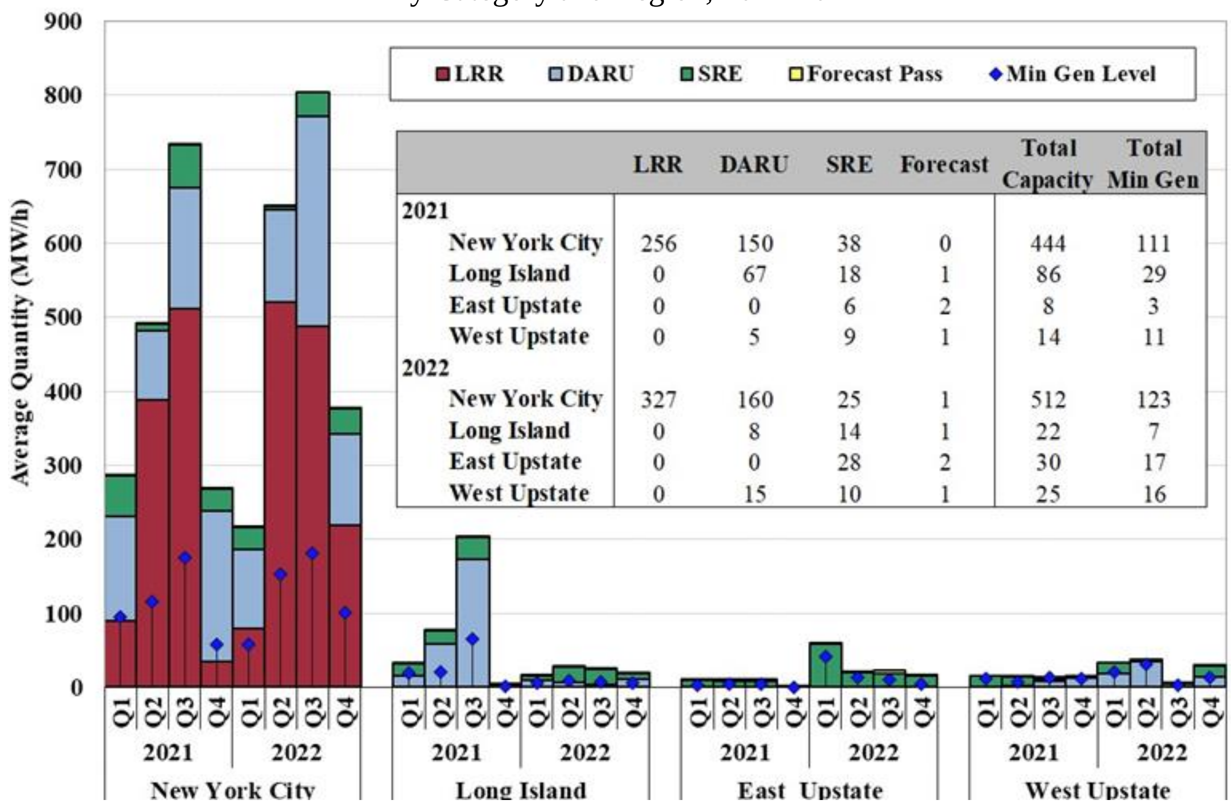
fully represented in the market model; or (b) maintain reliability of the lower voltage transmission system and the distribution system.

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 23 summarizes the quantities of four types of reliability commitment (i.e., DARU, LRR, SRE, and Forecast Pass) by region in 2021 and 2022.[120]

Figure 23: Supplemental Commitment for Reliability in New York
By Category and Region, 2021-2022



	LRR	DARU	SRE	Forecast	Total Capacity	Total Min Gen
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
2022						
New York City	327	160	25	1	512	123
Long Island	0	8	14	1	22	7
East Upstate	0	0	28	2	30	17
West Upstate	0	15	10	1	25	16

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

Roughly 590 MW of capacity was committed on average for reliability in 2022, up modestly by 7 percent from 2021. Reliability commitment in New York City continued to account for most (87 percent) reliability commitments in 2022. Reliability commitments in New York City for N-1-1-0 requirements rose by 15 percent from 2021 to 2022.

For many years, we have observed excess reliability commitments for NOx Bubble requirements in New York City.[121] Specifically, in 2022, a steam turbine was committed solely to satisfy the NOx rule on 59 days during the Ozone season. These NOx-only steam turbine commitments could have been avoided on 46 days if the NYISO and ConEd were allowed to consider whether the gas turbines were actually needed for reliability before committing the associated steam turbine.[122] 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 are being 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. Such measures would prevent the unnecessary deployment of resources and reduce the overall costs of ensuring grid reliability while likely reducing NOx pollution.

Reliability commitments on Long Island fell from 2021 to 2022 primarily because of less frequent transmission outages of tie lines between upstate and Long Island (i.e., the Y49 and Y50 lines) in 2022.[123] However, despite the decrease, reliability commitments still occurred on 27 days in 2022 to satisfy N-1-1-0 criteria (i.e., normal line loading following the two largest contingencies), indicating that the current 30-minute reserve requirement for Long Island is sometimes inadequate to maintain reliability. Although the current reserve requirement is usually adequate to maintain security and reliability following the largest contingency, it is not necessarily adequate to satisfy N-1-1-0 criteria. This lack of consideration for N-1-1-0 criteria in the market software means that system operators have to rely on OOM commitments when needed, leading 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.[124]

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121 See Figure A-105 in the Appendix for more information about this analysis.

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

123 DARU commitments were frequent in 2021 during a 46-day summer peak period when both Y49 and Y50 tie lines were out of service, while there were no such overlapping outages in 2022.

124 See Recommendation #2021-2.

Additionally, although the day-ahead and real-time markets schedule resources to satisfy reserve requirements on Long Island, reserve providers are currently 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 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.[125] 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.[126]

In contrast to Long Island, reliability commitments in upstate regions rose in 2022. The increase reflected OOM commitments that were made to satisfy the N-1-1 criteria: (a) in the North Country load pockets on 67 days; and (b) in the Capital Zone 115 kV network on 35 days. Modeling reserve requirements in these local load pockets would improve market efficiency and establish proper market signals for future investments, similar to out recommendation for Long Island. Overall, improving the market efficiency and reliability of the power grid in New York State requires careful consideration of local load pockets and the specific reserve requirements needed to ensure adequate reliability in those areas.

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 was incorrectly categorized as slow-start capacity in the Forecast Pass. Consequently, most of the FCT commitments would not have occurred if these quick-start units were recognized as quick-start by the software.[127] 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 were significantly lower than the forecasted load and reserve needs on most days.[128] 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

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[125] See Recommendation #2019-1.

[126] See 2022 Master Plan project *Long Island Reserve Pricing,* November 2022.

[127] See Section V.F in the Appendix for more information about this analysis.

[128] See Figure A-107 in the Appendix for more information about this analysis.

through the market as part of the effort to set operating reserve requirements dynamically.[129] In some cases, the operating reserve requirements could be satisfied with resources having longer lead times than the current 10-minute and 30-minute reserve providers. Therefore, we have recommended that the NYISO evaluate the need for longer lead time reserve products.[130] However, before creating longer lead time reserve products, it may be more efficient to represent such requirements in the market 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 2022 if the NYISO were to devise a day-ahead market reserve requirement.[131] 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.

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 $3.59 per MWh in most areas to as much as $7.70 per MWh in the Astoria West/Queensbridge load pocket in 2022. These price increases would be in addition to the prices of operating reserve products in New York City.

129 See Recommendation #2015-16.

130 See Recommendation #2021-1.

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

Table 7: Day-ahead Reserve Price Estimates
Selected NYC Load Pockets, 2022

Area	Average Marginal Commitment Cost ($/MWh)
NYC 345 kV System	$3.59
Selected 138 kV Load Pockets:	
Astoria West/Queensbridge	$7.70
Vernon	$5.40
Freshkills	$5.90

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.[132] In previous SOM Reports, 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, finding that this pricing enhancement would have had a large impact.[133] NYISO is considering modeling New York City load pockets as a follow-up to its *Dynamic Reserves* project.[134] 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.

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.[135]

The quantity of OOM dispatch rose by 10 percent from 2021 to 2022. The rise was mainly due to a modest increase in OOM actions in the upstate regions. Frequent transmission outages were taken in these areas to facilitate transmission upgrade projects, which resulted in more frequent

132 See Recommendation #2017-1 in Section XII.

133 See 2021 SOM Report, Section VII.D.

134 See 2022 Master Plan project *More Granular Operating Reserves*, November 2022.

135 This reports the quantity of OOM actions taken either by NYISO operators (designated as OOM type 1) or by local Transmission Owners (designated as OOM type 2). Figure A-110 in the Appendix provides additional detail in 2021 and 2022 for each region.

transmission bottlenecks in nearby areas.[136] As a result, more OOM dispatches were required to manage constraints that were not secured or not fully represented in the market.

Table 8: Frequency of Out-of-Merit Dispatch
By Region, 2021 - 2022

Region	OOM Station-Hours		
	2021	2022	% Change
West Upstate	191	366	92%
East Upstate	587	824	40%
New York City	542	400	-26%
Long Island	2316	2397	3%
Total	**3636**	**3987**	**10%**

For instance, the Capital Zone experienced a surge in OOM dispatches from mid- to late-July due to outages on the Greenbush Bus and Greenbush-Calverton 115 kV line. Local Transmission Owners often had to OOM several units down to manage congestion on unmodelled 115 kV facilities in the Albany-Greenbush area during this period. The West Zone saw an increase in OOM dispatches in January and February, which coincided with a rise in congestion caused by large amounts of Lake Erie Circulation. During this period, Michigan PARs were frequently unable to regulate for controlling loop flows.

Long Island exhibited a comparable amount of OOM dispatches between 2021 and 2022, accounting for more than 60 percent of OOM dispatches each year. OOM actions on Long Island 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 successfully integrated five 69 kV constraints into its day-ahead and real-time markets since April 2021. This integration has resulted in a significant decrease in the number of OOM dispatches, with a reduction of almost 50 percent in 2021 and 2022 compared to the levels recorded in 2020. The NYISO has a process to periodically 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 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.[137] We provide one approach to developing surrogate constraints in Section III.E of the Appendix, which could be used to satisfy TVR constraints within the market models.

136 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.

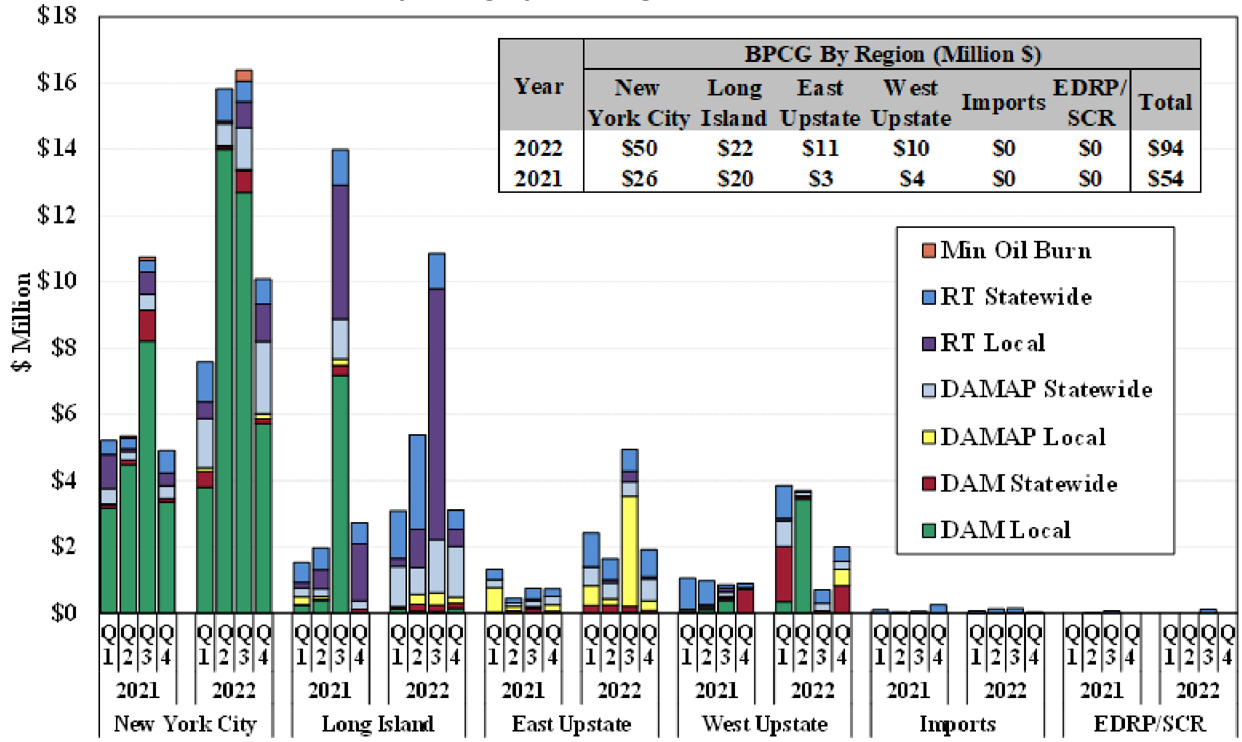
137 See Recommendation #2021-3.

G. Guarantee Payment Uplift Charges

To ensure full as-bid costs are guaranteed to certain market participants, the NYISO recovers any additional payments that are not recouped from LBMPs and other market revenues through guarantee payment uplift charges. However, these uplift charges are difficult to hedge and do not provide transparent economic signals to market participants and potential investors. Therefore, it is important to minimize these charges. When the markets reflect reliability requirements and system conditions efficiently, uplift charges should be relatively low.

Figure 24 shows guarantee payment uplift for four local reliability categories and three non-local reliability categories in 2021 and 2022 on a quarterly basis.[138] The figure shows that guarantee payment uplift totaled $94 million in 2022, up 74 percent from 2021. The increase was driven primarily by higher gas prices, which increased the commitment cost of gas-fired units. Higher supplemental commitments and more frequent OOM actions (as discussed in previous sections) were also important contributors.

Figure 24: Uplift Costs from Guarantee Payments in New York
By Category and Region, 2021 – 2022



In 2022, New York City accounted for $50 million, or 53 percent, of BPCG uplift, representing a 92 percent from 2021. Over $36 million, or 72 percent of total BPCG uplift, was paid to generators that were committed for N-1-1-0 local requirements. The increase in BPCG uplift was

138 See Figure A-111 and Figure A-112 in the Appendix for a more detailed description of this analysis.

driven primarily by higher natural gas prices and increased supplemental commitments. Higher emission costs, particularly NOx emission costs were also an important contributor. During the ozone season in 2022, NOx emission costs for gas-fired steam turbines rose to an average of up to $12 per MWh, compared to an average of less than $2 per MWh recorded in 2021.[139] We have recommended the NYISO model local reserve requirements to satisfy these N-1-1-0 needs. This approach should greatly reduce associated BPCG uplift and provide more transparent and efficient price signals to the market.[140]

Long Island accounted for $22 million (or 23 percent) of BPCG uplift in 2022, up 10 percent from 2021. Nearly $10 million was paid in the category of real-time local BPCG uplift, with approximately 75 percent going to high-cost peaking resources that were frequently needed in the summer months to satisfy the Transient Voltage Recovery (TVR) needs on the East End of Long Island. We have recommended the NYISO consider modeling local TVR requirements on Long Island in the day-ahead and real-time markets.[141] 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.[142] On 27 days, additional resources were either DARU-committed or SRE-committed to satisfy N-1-1-0 requirements for Long Island, resulted in a modest $1 million uplift in 2022, compared to over $7 million in 2021. To maintain reliability in a more efficient way, we have recommended the NYISO implement full reserve requirements in Long Island instead of relying on out-of-market actions.[143]

BPCG uplift payments in upstate regions rose from roughly $7 million in 2021 to $21 million in 2022. Most of this uplift went to units that were either supplementally committed or dispatched out-of-merit to manage non-market-secured transmission constraints or local reserve needs. For example, more than $4 million was paid to units that were supplementally committed to manage local reserve needs in the North Country load pockets (67 days in the first and fourth quarters) and the Capital Zone 115 kV network (35 days in March and April). Another $4 million was paid to units that were supplementally committed for local voltage and thermal needs in the West Zone from late March to late May. During a ten-day period in mid-July, over $3 million of DAMAP accrued in the Capital Zone as several units were frequently dispatched out-of-merit to manage unmodeled 115 kV constraints during transmission outages. It would be beneficial to incorporate more of these requirements into the day-ahead and real-time markets.

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139 However, only a subset of ST-owners have requested to reflect this cost in reference levels. These costs are partially offset by the rules for allocating NOx allowances in future years, which tend to allocate more future allowances to generators that operate more in the current year.

140 See Recommendation #2017-1.

141 See Recommendation #2021-3.

142 See Section VII.B for this analysis.

143 See Recommendation #2021-2.

VII. 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 2022:

- Day-ahead and real-time transmission congestion
- Constraints managed using out-of-market actions
- Transmission congestion contract prices and payments

In addition, general congestion patterns are summarized in the Appendix Section III, while the Market Operations section evaluates elements of congestion management.[144]

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.[145] 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 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 25 evaluates overall congestion revenues and shortfalls in the past ten years, showing annual 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.

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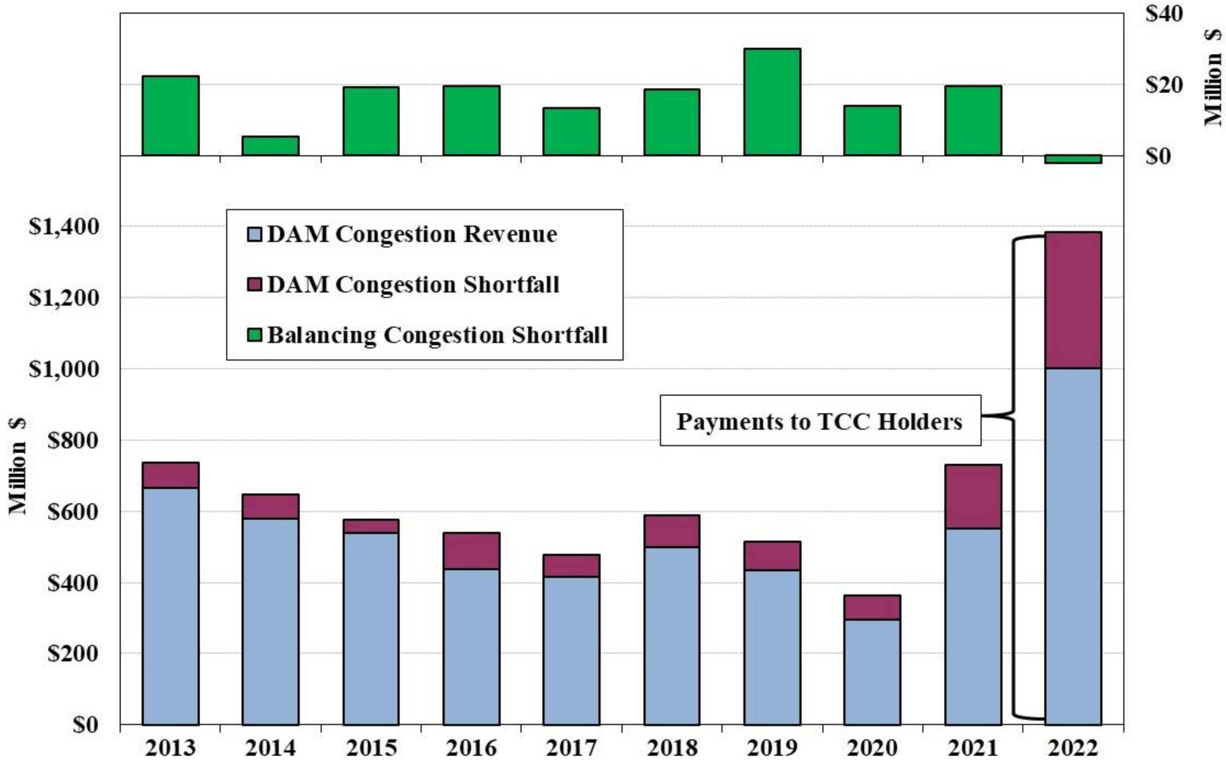
144 The Market Operations section evaluates pricing during transmission shortages (VI.A), use of reserves to manage NYC congestion (VI.D), and coordinated congestion management with PJM (Appendix V.C).

145 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 25: Congestion Revenues and Shortfalls
2013 – 2022



The figure shows a notable increase in both day-ahead congestion revenues and day-ahead congestion shortfalls in 2022, while balancing congestion shortfalls fell substantially. We discuss these changes further in the subsections below.

Day-Ahead Congestion Revenues

In 2022, day-ahead congestion revenues surged to $1 billion, marking an 81 percent increase from 2021 and more than doubling the average amount recorded from 2013 to 2021. The surge in congestion resulted from higher natural gas prices and gas price spreads between regions, which led to higher redispatch costs. The average natural gas prices rose 89 percent in 2022 from 2021, nearly double the average recorded from 2013 to 2021. Nearly 40 percent of day-ahead congestion revenues were generated in the first quarter when natural gas prices spiked on cold days. Significant regional gas spreads emerged during these events, which increased congestion from West to East New York and from PJM to New York to New England.

Another key driver of increased congestion was frequent transmission outages that affected the Central-East interface. Over the past two years, lengthy transmission outages were required throughout the year to support the construction work of the Central-East Energy Connect project,[146] which often led to a reduction in Central-East transfer capability. Typically, the interface transfer capability was reduced by more than 1 GW in the shoulder months and by 200 to 300 MW in the summer. Moreover, Central-East congestion has generally increased since the retirement of Indian Point 2 in April 2020 and Indian Point 3 in April 2021. As eastern New York has become more reliant on 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 has risen from an average of less than 40 percent of day-ahead congestion in the years before 2021 to 56 percent in 2021 and 60 percent in 2022.

Congestion from Capital to Hudson Valley also increased significantly in 2022 largely because of lengthy transmission outages required to support the construction work of Public Policy Transmission Project Segment B. Reduced transfer capability on this corridor has increased the impact of loop flows across the border with New England in real-time. Unexpected swings in loop flows resulted in real-time congestion that more than doubled the day-ahead congestion.[147]

Long Island congestion increased modestly in 2022 as higher natural gas prices were partly offset by less frequent transmission outages during peak summer conditions. One of the two 345 kV lines from upstate to Long Island was out of service for 195 days, comparable to 2021. However, both 345 kV lines were operational during the summer peak periods in 2022, while both lines were out of service for 46 days during the summer peak periods in 2021.

One region where congestion decreased was the West Zone where congestion fell by nearly 50 percent in 2022. This was largely due to the completion of the Empire State Line Public Policy Transmission project, which included the PAR-controlled Dysinger-East Stolle 345 kV line that began operation before summer 2022. These upgrades have alleviated congestion and provided additional operational flexibility in the area.

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146 This is also referred to as the Public Policy Transmission 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.

147 See Figure A-57 in the Appendix.

Day-Ahead Congestion Shortfalls

Day-ahead congestion shortfalls occur when the day-ahead network capability is less than the capability reflected in TCCs issued, while day-ahead congestion surpluses (i.e., negative shortfalls) occur when day-ahead schedules across a binding constraint exceeds the amount of TCCs. Table 9 shows total day-ahead congestion shortfalls for selected transmission facility groups.[148] Day-ahead congestion shortfalls continued to rise, up from $180 million in 2021 to $384 million in 2022. This increase was primarily due to more planned transmission outages and, to a lesser degree, more forced transmission outages that were not fully reflected in the TCC market. We discuss these shortfalls by transmission path below.

Table 9: Day-Ahead Congestion Shortfalls in 2022

Facility Group	Annual Shortfalls ($ Million)
Central to East	$335
Long Island Lines	$24
West Zone Lines	$18
North to Central	$15
All Other Facilities	-$8

Central to East – Shortfalls increased sharply on this path from $72 million in 2021 to $335 million in 2022, accounting for roughly 90 percent of all shortfalls in 2022. The increase resulted primarily from the following planned transmission outages:

- The Edic-New Scotland 345 kV circuit (i.e., the old "14 line") was out of service from March 8 to May 27, which reduced the interface transfer limit by approximately 1300 MW. On September 8, this line was permanently removed from service. It was replaced by the new Edic-Gordon Road 345 kV circuit (i.e., the new "14 line"), which has been in service since September 13, and the new Gordon Road-New Scotland 345 kV circuit ("55 line"), which has been in service since September 20.
- The Edic-Gordon Road 345 kV circuit (new "14 line") was out of service from October 10 to November 1, which reduced the interface limit by approximately 900 MW.
- The Marcy-New Scotland 345 kV circuit ("18 line") was out of service from November 2 to December 6, which reduced the interface limit by approximately 1500 MW.
- The Marcy-Frasannex 345 kV circuit ("UCC2-41 line") was out of service from March 1 to April 21 and from August 11 to September 9, which reduced the interface limit by approximately 300-500 MW.

These outages were taken primarily to support the construction work of the Central East Energy Connect project. This project is expected to increase the transfer capability from Central to East New York by at least 350 MW upon completion.

148 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 – Long Island lines experienced the second-largest share of shortfalls in 2022. The primary cause was the following outages of tie lines between upstate and Long Island:

- The Sprainbrook-East Garden City 345 kV circuit (“Y49 line”) was out of service in two separate periods, one from March 12 to June 10 and the other from October 2, 2022 to May 31, 2023, resulting in a total of 194 days of downtime in 2022.
- The Dunwoodie-Shore Road 345 kV circuit (“Y50 line”) was out of service for a combined 11 days in January and September.

However, the outages were shorter and overlapped less with high demand conditions than in 2021, causing congestion shortfalls to fall from $55 million in 2021 to $24 million in 2022.

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 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 220 MW in the day-ahead market in 2022. 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.[149]

West Zone – This corridor exhibited shortfalls of $18 million 2022, most of which occurred before the completion of the Empire State Line project on several days in January because of the outages of multiple Niagara-Packard 115 kV lines and the Robinson-Stolle Road 230 kV line.

North to central New York lines – Day-ahead congestion shortfalls on these lines accounted for $15 million in 2022. The primary driver was transmission outages taken throughout the year for the Moses-Adirondack Smart Path Reliability Project.

The NYISO allocates most of the day-ahead congestion shortfalls that result from transmission outages to the specific responsible transmission owners.[150] In 2022, the NYISO allocated 86 percent of these shortfalls in this manner, up from 69 percent in 2021. 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).

149 See Recommendation #2012-8.

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

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.[151] Table 10 shows balancing congestion shortfalls by transmission facility group.[152]

Table 10: Balancing Congestion Shortfalls in 2022 [153]

Facility Group	Annual Shortfalls ($ Million)
West Zone Lines	
Ramapo, A & JK PARs	**$0.5**
Other Factors	**$0.6**
Central to East	
Ramapo, A & JK PARs	**-$11.7**
Other Factors	**-$6.2**
Capital to Hud VL	
Ramapo, A & JK PARs	**-$3.3**
Other Factors	**-$0.9**
TSA Constraints	**$11.9**
External	**$12.3**
All Other Facilities	**-$0.6**

Congestion shortfalls are small on most days, but they can be very large on a limited number of days when unexpected events occur. In 2022, Thunder Storm Alert ("TSA") events, which require the NYISO to operate conservatively by reducing transmission flows through Southeast New York, happened on 22 days and caused nearly $12 million in shortfalls.

Another notable contributor to shortfalls in 2022 was the curtailment of external transactions, which accounted for another $12 million of shortfalls. Most of this was generated on December 23 and 24, when PJM operators managed capacity deficiencies by curtailing exports to New York. The resulting shortfalls were uplifted to load systemwide in the New York market.

However, the impact of these shortfalls was mitigated by the surpluses generated by the NJ-NY PARs (Ramapo, A, & JK PARs) during their real-time operations under the PJM-NY M2M

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

152 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.

153 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.

process. In 2022, the PARs contributed almost $15 million in net surpluses, which helped reduce overall congestion costs across the Central-East interface and from Capital to Hudson Valley. This has been a significant benefit to customers in New York.

B. Management of Constraints using Out-of-Market Actions

Transmission constraints on 100 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, some transmission constraints, particularly on lower voltage networks, are resolved primarily through out-of-market actions such as:

- 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.

The NYISO started to incorporate most 115 kV constraints in the day-ahead and real-time markets in December 2018.[154] Furthermore, the NYISO has incorporated five 69 kV constraints on Long Island in the day-ahead and real-time markets since mid-April 2021.[155] These developments have allowed resources that were previously dispatched out-of-merit to manage these constraints to be scheduled economically, which has helped improve the efficiency of scheduling, pricing, and market incentives in Upstate New York and Long Island.

Notwithstanding these improvements, out-of-market actions to manage constraints are still frequent in some areas. Table 11 shows the frequency of such actions in six areas. The table summarizes the number of days from 2020 to 2022 when OOM actions were used in each area.

154 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.

155 The NYISO has an on-going process to evaluate and incorporate additional 69 kV constraints into the market models. The Brentwood-Pilgrim 69 kV line and the Elwood-Pulaski 69 kV line were incorporated in April 2021. The Deposit-Indian Head 69 kV line and the West Hempstead-Malverne 69 kV line were incorporated in April 2022. The Holtsville-West Yaphank 69 kV line was incorporated in March 2023.

Table 11: Constraints on the Low Voltage Network in New York[156]
Summary of OOM Days for Managing Constraints, 2020-2022

Area	# of Days with OOM Actions		
	2020	2021	2022
West Zone	13	10	84
Central Zone	6	9	5
North & MHK VL	26	48	82
Capital Zone	8	27	66
Central Hudson	5	4	21
Long Island	137	120	135

The table shows that OOM actions rose in 2022. In the West Zone, OOM actions rose on many days in the first quarter partly because the Ontario-Michigan PARs were not able to control Lake Erie loop flows. OOM actions also rose in the second quarter during the planned outage of the Dunkirk 115 kV M2 Bus, which required one unit to be supplementally committed almost every day to satisfy local voltage and thermal needs.

OOM commitments rose in the North Zone and the Capital Zone primarily to satisfy local N-1-1 load pocket requirements. Such OOM commitments occurred on 67 days to maintain adequate reserves in the North Country load pocket, which is not modeled in the day-ahead and real-time markets. Large OOM commitments occurred on many days with small (< 10 MW) reserve needs, leading to sizable uplift. In addition, wind curtailments occurred on 34 of the 67 days partly because of increased production from the OOM committed units. Wind generation is currently not counted towards satisfying the local N-1-1 requirements in load pockets, so reliability commitments increase supply in the area, often causing additional wind curtailment.

OOM commitments for the N-1-1 requirements in the Capital Zone 115 kV network occurred on 35 days. This need arose because of the combined effects of: (1) transmission outages that were taken to facilitate Public Policy-related transmission work, reducing import capability into the 115 kV pocket; and (2) seasonal maintenance of generators, reducing available supply in the 115 kV pocket. All of these commitments were SREs, which tend to depress prices and generate uplift in the real-time market, although this uplift was not significant in 2022.

Long Island also had 27 days when supplemental commitments were made for reserve needs under tight system conditions (e.g., severe weather and tight gas conditions, or emergency outages of inter-ties, or trip of large generators). We have recommended the NYISO model the full reserve requirements for Long Island in the day-ahead and real-time markets.[157] It would be

156 See Section III.D in the Appendix for more details on the use of various resource types in 2022.

157 See Recommendation #2021-2.

beneficial to model full reserve requirements in other applicable local areas as well, such as the North Country load pocket and the Capital Zone 115kV network. Modeling these local N-1-1 requirements in the market software would improve scheduling efficiency, send efficient investment signals, and help integrate renewable and storage resources.

OOM actions to manage low-voltage network constraints are still most 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 Transient Voltage Recovery ("TVR") constraints four areas of Long Island in 2021 and 2022. The table also shows the average estimated LBMP in each pocket based on the marginal costs of resources used to manage the constraint(s).

Table 12: Constraints on the Low Voltage Network in Long Island
Frequency of Action and Price Impact, 2021-2022

Year	Long Island Load Pockets	69kV OOM		TVR OOM		Avg. LBMP	Est. LBMP w/ Modeling Local Constraints
		#Hours	#Days	#Hours	#Days		
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
2022	**Valley Stream**	604	65			$98.08	$99.50
	Brentwood	38	8			$98.31	$98.34
	East of Northport	148	25			$97.30	$98.37
	East End	84	7	814	68	$99.40	$127.95

Although still frequent, OOM actions have fallen substantially since April 2021 when NYISO began to secure 69 kV constraints in the market. This allows resources that were frequently dispatched OOM to manage these constraints to be scheduled economically on 133 days in 2022.

The NYISO has an on-going process to periodically evaluate and incorporate additional 69 kV constraints into the market models as needed. This should continue to help reduce the OOM needs on Long Island and improve scheduling and pricing efficiency. Continuing to set LBMPs on Long Island more efficiently to recognize the marginal cost of satisfying local transmission constraints will provide better signals for future investment. However, this process does not address the TVR requirements on the East End of Long Island where OOM actions for this need are frequent on high load days. The high costs of turning on oil-fired resources to meet the TVR needs are not currently reflected in LBMPs. Hence, we recommend NYISO model East End

TVR needs (using surrogate constraints) in the market software.[158] We illustrate in Section III.E of the Appendix one approach to develop surrogate constraints that could be used to satisfy TVR constraints within the market models.

C. Transmission Congestion Contract Prices and Payments

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 2021/22 and Summer 2022 Capability Periods (i.e., November 2021 to October 2022). The following factors contributed to profits in losses on different paths in 2022: summarizes TCC cost and profit for the evaluation period separately for inter-zonal and intra-zonal TCCs.[159]

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

Table 13: TCC Cost and Profit

Winter 2021/22 and Summer 2022 Capability Periods

	TCC Cost ($ Million)	TCC Profit ($ Million)	Profit as a Percent of Cost
Intra-Zonal TCC			
Capital & Hud VL	$70	$77	111%
Long Island	$14	$10	70%
New York City	$13	$10	75%
All Other	$22	-$6	-28%
Total	**$118**	**$91**	**77%**
Inter-Zonal TCC			
Other to Central New York	$72	$50	69%
Other to Southeast New York	$174	$55	32%
New York to New England	$92	-$34	-37%
All Other	$52	-$17	-33%
Total	**$391**	**$53**	**14%**

Market participants purchasing TCCs in the auctions covering the 12-month period from November 2021 to October 2022 netted a total profit of $144 million. Overall, the net

158 See Recommendation #2021-3.

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

profitability for TCC holders in this period was 28 percent (as a weighted percentage of the original TCC prices), comparable to the 26 percent in the previous 12-month period.

The following factors contributed to profits in losses on different paths in 2022:

- TCC purchasers realized average profits of 14 percent on inter-zonal transmission paths and an average gain of 77 percent on intra-zonal paths. Elevated natural gas prices and more costly transmission outages were the primary drivers of higher-than-anticipated congestion into Central New York and East New York in 2022, leading TCC purchasers to profit on most intra-zonal and inter-zonal transmission paths within these regions.
- TCC purchasers experienced the highest profit on transmission paths from Central to East and from Capital to Hudson Valley, driven by a surge in day-ahead congestion in 2022. The increases (of 96 percent and 584 percent, respectively) in 2022, were driven primarily by frequent and extended transmission outages in these areas to facilitate the Public Policy Transmission Projects. This outages greatly reduced transfer capacity along affected transmission corridors and led to a pronounced rise in congestion levels.
- TCC purchasers realized profits of 69 percent on transmission paths into Central New York. This was notable as it corresponded with increases of 17 percent and 322 percent on transmission paths from North to Central and from West to Central in 2022. Two key contributors to the elevated congestion levels from the previous year were transmission outages and changes in day-ahead offer patterns of wind resources.
- TCC purchasers lost 37 percent on transmission paths from New York to New England. Congestion on these paths decreased in 2022 because higher congestion across the Central to East interface made it more costly to export to New England.

These results indicate that TCC prices generally reflect levels of congestion anticipated at the time of the auctions. The TCC buyers' profits and losses on most transmission paths are typically consistent with changes in day-ahead congestion patterns from previous years, emphasizing the importance of anticipated congestion levels in evaluating TCC profitability. Further, unexpected congestion, which can be caused by lengthy unplanned outages, is often a key driver of TCC profitability. TCC auction results also suggest that market expectations of congestion improve closer to real-time operations, consistent with the availability of more accurate information 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.

VIII. 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 2022 in Subsection A;
- Principles for setting efficient prices in the capacity market (Subsection B); and
- Key inefficiencies in the existing capacity market design in Subsection C. To address these inefficiencies, we recommend capacity market reforms in the following areas:
  - Defining additional pricing locations in the capacity market each year to capture emerging transmission bottlenecks (Subsection D),
  - Consider implementing location-based marginal cost pricing of capacity ("C-LMP") in the longer-term (Subsection E),
  - Reforming capacity accreditation to ensure that supply resources are compensated efficiently as the resource mix evolves (Subsection F),
  - Paying resources efficiently when locational capacity requirements are driven by transmission security limits (Subsection G),
  - Providing efficient capacity compensation for transmission investments (Subsection H), and
  - Enhancing the market to better reflect seasonal capacity value in Subsection I.

A. Capacity Market Results in 2022

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 2022/23 Capability Year and year-over-year changes in key factors from the prior Capability Year.[160]

Table 14 shows that capacity prices fell in all regions despite modest reductions in internal installed capacity. Changes to the administrative parameters used in the demand curves, most

160 Results for 2022/23 capability year, which runs from May 2022 through April 2023, are displayed through February 2023.

prominently the Installed Reserve Margin ("IRM") and Locational Capacity Requirements ("LCRs"), were key drivers of year-over-year capacity price trends.

Table 14: Capacity Spot Prices and Key Drivers by Capacity Zone[161]
2022/23 Capability Year

	NYCA	G-J Locality	NYC	LI
UCAP Margin (Summer)				
2022 Margin (% of Requirement)	8.3%	11.9%	15.4%	11.8%
Net Change from Previous Yr	3.4%	0.2%	1.6%	3.0%
Average Spot Price (Full Year)				
2022/23 Price ($/kW-month)	$3.05	$3.19	$3.34	$5.08
Percent Change Yr-Yr	-16%	-12%	-10%	-16%
Change in Demand				
Load Forecast (MW)	-566	-286	-293	-111
IRM/LCR	-1.1%	1.6%	0.9%	-3.4%
ICAP Requirement (MW)	-1,033	-8	-137	-289
Change in UCAP Supply (Summer)				
Generation & UDR (MW)	-358	-171	-87	-224
SCR (MW)	-2	13	14	-5
Import Capacity (MW)	119			
Change in Demand Curves (Summer)				
ICAP Reference Price Change Yr-Yr	14%	11%	7%	0%
Net Change in Derating Factor Yr-Yr	1.0%	1.2%	0.6%	1.4%

Rest of State spot prices fell by roughly $0.57/kW-month (16 percent) to average $3.05/kW-month for the year. The following factors contributed to lower prices:

- The IRM fell by 1.1 percent to 119.6 percent systemwide.
- The systemwide peak load forecast fell 566 MW, further reducing the ICAP Requirement.
- A pattern of unsold capacity from non-pivotal portfolios that drove systemwide prices higher across many months of 2021/22 did not manifest during the current Capability Year.
- However, these factors were partly offset by increased peak Winter Period exports, downstate peaking unit retirements ahead of the Winter Capability Period, and higher ICAP Reference Prices.

Capacity prices in the G-J Locality fell from a year ago despite this region separating from the systemwide price across much of the summer months for the first time in a few years. The effects of the higher 2021/22 IRM outweighed the 1.6 percent increase in the G-J LCR for 2022/23.

161 See Section VI.D in the Appendix for more details.

Overall, the ICAP requirement for NYC declined by 137 MW due to a 290 MW reduction in the peak load forecast. This was partially offset by a 0.9 percent increase in the LCR which, coupled with the lower IRM systemwide, led to the NYC summer prices rising above the systemwide price. As with the outcomes in G-J, however, the price effect of last year's higher IRM outweighed the impact of the NYC LCR binding this summer and resulted in lower annual capacity prices.

Finally, in Long Island spot prices fell by $0.94/kW-month (16 percent). The ICAP requirement fell by 290 MW due to both a lower peak demand forecast (111 MW) and a 3.4 percent drop in the LCR. The effects of these drivers on resultant prices were muted to some extent by generator retirements in Long Island starting early in the Summer 2022.

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.

In this subsection, we evaluate the efficiency of LCRs that the NYISO determined for the upcoming 2023/24 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 some UCAP to an area.[162]
- 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.

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

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 26 and Figure 27 show the estimated MRI, Net CONE, and CRI for each locality and zone based on the 2023/24 Final LCR Case.[163]

Figure 26: Marginal Reliability Impact (MRI) and Net CONE by Locality and Zone
2023/2024 Capability Year

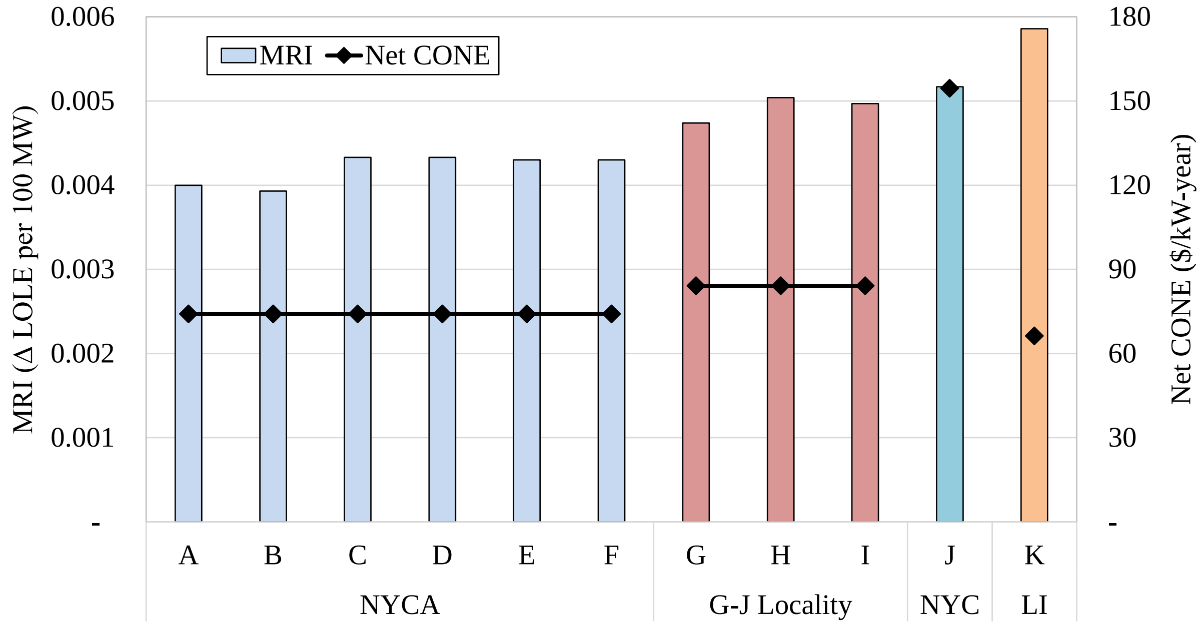
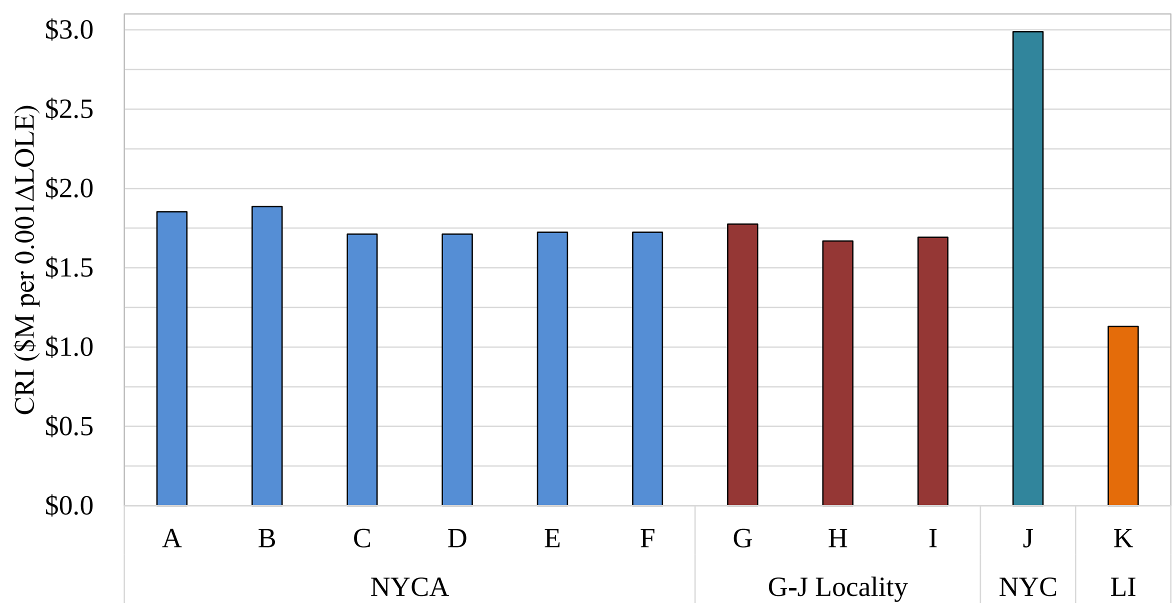


Figure 27: Cost of Reliability Improvement (CRI) by Locality
2023/2024 Capability Year at Level-of-Excess Conditions



163 See Section VI.FF of the Appendix for the methodology and assumptions used to estimate the CRI and MRI.

It is apparent from Figure 27 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 K (at $1.1 million per 0.001 events) and the maximum CRI-value location of Zone J (at $3.0 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 2023/24 Capability Year (105.2 percent) is below the efficient level.
- The LCRs for the NYC and G-J Locality capacity zones were set at their minimum floors determined by transmission security limits (TSLs). While the high CRI in Zone J suggests it would be efficient to shift capacity to other zones, the Optimizer cannot reduce the Zone J LCR because doing so would violate the TSL-based minimum requirement. The impact of the TSLs on efficient compensation of capacity suppliers is discussed further in Subsection G.

Figure 27 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 be much more valuable for satisfying New York's reliability needs than resources in other zones. Ideally, these zones would be separated and priced to reflect this difference in reliability value.

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 MRI / higher CRI than zones C to F, although resources in all of these zones receive the same capacity price. This reflects transmission bottlenecks between zones B and C.[164]
- H&I Pocket – Zone G has a lower MRI / higher CRI than zones H and I, which receive the same price. This is caused by bottlenecks on the UPNY/CONED interface between zones G and H.[165]

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164 In our 2021 State of the Market report, we found that zones A and B had a *lower* CRI than zones C-F based on the 2022/23 IRM case at level-of-excess conditions. This result was driven by limitations in the modeling of large energy-limited hydro resources in Zone A, which resulted in an apparent need for zones A and B to import capacity from other areas. NYISO adopted modeling improvements to energy-limited resources for the 2023/24 IRM Study that more realistically represented the hydro resources in Zone A, and NYISO increased the Zone C to Zone B transfer limit following local upgrades by transmission owners. These changes caused the bottleneck between zones B and C to revert to binding in the eastbound direction, as had been observed in past years. See October 7, 2021 presentation to NYSRC "Sensitivity Using GE MARS in Modeling ELRs", available here, and NYSRC 2023/24 IRM Technical Study Report at p. 18, available here.

165 In our 2021 State of the Market Report, we did not find a difference in MRI and CRI values between zones G and zones H and I. The reemergence of the bottleneck between zones G and H was caused by planned operational changes by Con Edison placing the M51, M52, 71 and 72 series reactors in service beginning in May 2023, which reduced the UPNY/CONED transfer limit by 325 MW. We have historically found a lower MRI in Zone G compared to Zones H and I, but this difference was temporarily absent in the 2022/23

Additional information on these results is provided in Appendix Section VI.F. The remainder of this section applies the MRI and CRI concepts to evaluate the capacity market (Subsection C) and supports recommendations in six areas (Subsections E to I).

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. The capacity market lacks the locational requirements to procure resources efficiently due to the following deficiencies:

- Lack of an A&B Zone in the IRM-setting process – this has led to a higher IRM because capacity cannot be shifted into or out of Zones A and B in the Tan45 procedure.[166]
- Lack of a Staten Island Zone – 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.[167]
- Lack of an interface from Central to Eastern NY – Eastern New York (zones F-K) has a large amount of gas-only generators with limited fuel supplies in severe winter conditions, which may cause the bottleneck between zones E and F to exacerbate winter reliability issues.[168] However, winter-capable resources in Zone F will receive the "rest of state" price (applicable to zones A-F) even if they are more valuable for reliability.
- Lack of sub-zonal capacity market limits – This increases the deliverability limitations and associated upgrade costs, which can act as a barrier to efficient new investment. Projects in recent Class Year studies have been assigned inefficiently large transmission upgrades in order to obtain CRIS rights, which deters developers from investing. Incumbent generators in areas with limited deliverability receive inefficiently high compensation, reducing their incentive to retire and make headroom available for new resources. This issue is discussed in Section IV.A.

IRM Study when the Con Edison series reactors were assumed to be bypassed. See NYSRC 2023/24 IRM Technical Study Report at p. 18, available here.

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

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

168 See our comments on NYISO's 2022 Reliably Needs Assessment (RNA), available here.

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,[169] 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 in Appendix VI.F.

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 IRM itself embeds estimated LCRs determined using a different method from the Optimizer.[170] 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 reliability value of capacity in each region is based on the system being "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".

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

Generator Capacity Accreditation – New York's generation fleet is becoming more reliant on resources that are intermittent, duration-limited, and/or fuel-limited. Capacity accreditation reforms are needed to keep up with changes in the resource mix. NYISO recently adopted measures to annually calculate resources' capacity credit based on marginal reliability contribution for all resource types. To implement this "marginal accreditation" approach, it will be important to ensure that all resource types are modeled accurately in the resource adequacy model and the capacity market. Accreditation issues are discussed in detail in Subsection F.

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169 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.

170 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.

<u>Capacity Imports Are Not Scheduled or Priced Efficiently</u> – 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.

<u>Capacity Value of Transmission Is Not Compensated</u> – New transmission frequently provides substantial resource adequacy value. However, the NYISO does not compensate new merchant internal transmission for its capacity value.[171] 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:

- Subsection D highlights the need to define pricing locations in the capacity market annually to adapt to emerging transmission bottlenecks.
- Subsection E discusses the need for comprehensive location-based marginal cost pricing of capacity ("C-LMP") in the long-term.
- Subsection F proposes improvements to the capacity accreditation rules for each resource category.
- Subsection G proposes more efficient compensation of capacity suppliers when LCRs are set by transmission security considerations.
- Subsection H recommends efficient capacity compensation for transmission investments.
- Subsection I proposes changes to better reflect seasonal variations in capacity value.

D. Defining Additional Pricing Locations in the Capacity Market

Subsections C.1 and C.2 highlight inefficiencies in NYISO's capacity market caused by the lack of locational signals and problems with the LCR-setting process. Resolving these issues within NYISO's current capacity market framework will require the creation of more granular pricing zones combined with an LCR process designed to produce efficient outcomes. NYISO is investigating improvements to the LCR Optimizer which may partially address the issues raised in Subsection C.[172] The current process in NYISO's tariff for creating new capacity zones is wholly inadequate because it occurs only at four-year intervals, uses restrictive assumptions regarding the future resource mix, and relies on the flawed deliverability study methodology.[173]

171 The NYISO has proposed to enable capacity sales by internal UDRs through its Internal Controllable Lines project. This is an improvement, but will not value capacity of transmission projects that are not controllable UDR facilities.

172 See February 7, 2023 ICAPWG presentation "LCR Optimizer Enhancements – Kickoff", available <u>here</u>.

173 See discussion of the deliverability study methodology in Section IV.A. The most recent New Capacity Zone study was completed in December 2019 and is available <u>here</u>.

We recommend that NYISO establish a dynamic process to update pricing zones in the capacity market (Recommendation #2022-4). This recommendation would expand the number of capacity zones and replace the existing zone creation process, while keeping the structure of the capacity market largely intact. Its primary effect would be to (1) discount capacity payments to export-constrained areas that are currently overpriced (such as Staten Island), and (2) allow for reliability needs to be efficiently reflected in prices as they emerge (for example, if winter reliability needs cause the value of Zone F to increase relative to zones A-E in the coming years).

Under this recommendation, NYISO could annually establish capacity requirements using the LCR Optimizer for all zones and designated sub-zone areas, using the IRM Case GE-MARS topology as a starting point.[174] Prices would be determined using capacity market demand curves in regions that face binding import constraints in the annual IRM/LCR study. It may also be necessary to define demand curves applicable to export-constrained regions so that prices reflect the diminishing value of excess capacity in these areas.

E. Optimal Locational Marginal Cost Pricing of Capacity Approach ("C-LMP")

Subsection D proposes to annually establish more granular capacity zones. In the long term, it may be difficult to ensure that prices under a more complex zonal structure correspond to the marginal value of reliability in each area in a manner consistent with the principles laid out in Subsection B. Hence, we propose an alternative long-term approach to setting locational capacity prices that would address all of the issues discussed in Subsection C with one comprehensive approach. Our approach, which we call "C-LMP", would:

- 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,
- Reduce the complexity of administering the capacity market as the system evolves, and
- 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 relative to today's market when the system is at the "Level Of Excess" illustrating the long-term cost efficiencies that would be possible with an efficient market design. This study is described later in this subsection.[175]

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174 See "MARS Topology" under Appendix D of NYISO's 2022 Reliability Needs Assessment (RNA), available here. Additional modifications to the MARS topology may be needed so that requirements can be calculation for certain areas – for example, it would be necessary to model Staten Island constraints via sub-zone containing local capacity as opposed to the current method of setting a dynamic "J3->J" limit in the MARS topology to reflect Staten Island constraints.

175 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.

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: [176]

- 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 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.[177] 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 area in NYISO's planning model for each type of resource and load, (b) internal transmission interfaces, (c) external interfaces, and (d) UDRs. The MRI value for each type of resource would be set in accordance with marginal capacity accreditation principles recently adopted by NYISO.[178]

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.

176 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.

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

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

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 it.

The C-LMP approach would be less administratively burdensome because:

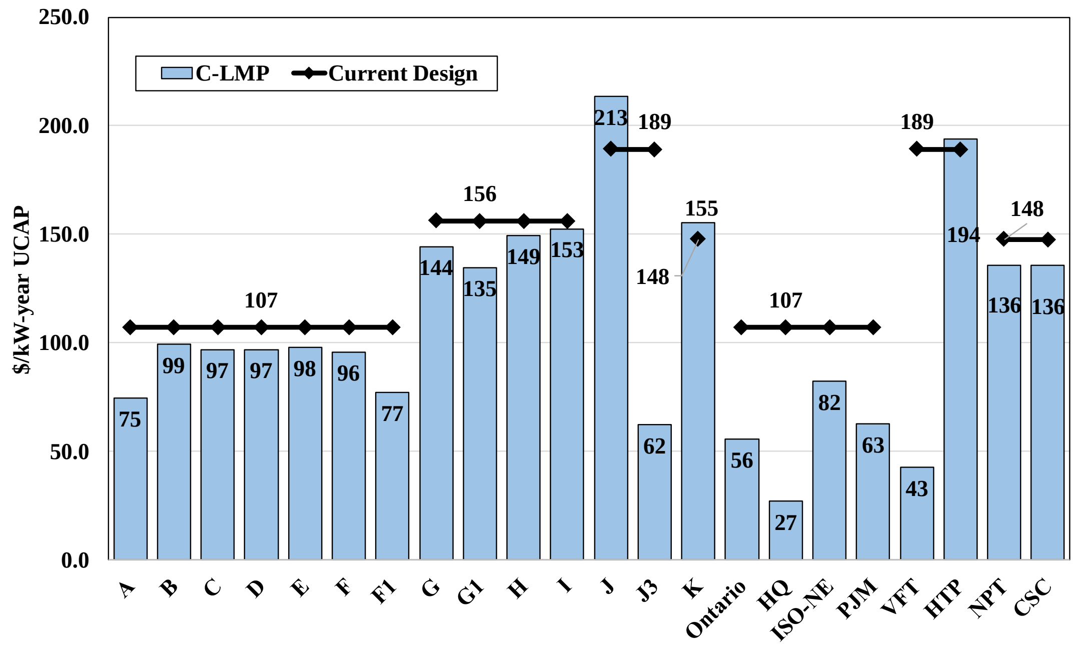
- It would require fewer approximations and simplifying assumptions than the current framework for determining capacity market parameters and prices.
- Changes in the network topology that result from new transmission investment and generation additions and retirements would transfer seamlessly from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

Analysis of C-LMP

Figure 28 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.[179]

Figure 28: Capacity Prices at the Level of Excess for C-LMP vs. Existing Framework

Based on 2019 Final LCR MARS Case



179 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.

Prices in Figure 28 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.

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.
- 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.[180] 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.[181,182]

F. Improving the Capacity Accreditation of Individual Resources

Capacity accreditation refers to the value of a resource's installed capacity relative to perfect capacity when it is 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 Reforms

Transactions in the capacity market are denominated in UCAP terms, so NYISO applies methods for converting the installed capacity (ICAP) value of each resource to UCAP. These conversion

180 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.

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

182 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.

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 2022, FERC approved tariff revisions proposed by NYISO to revise how it establishes resources' capacity credit ratings. Under the approved tariff revisions, NYISO will 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 initially take effect in the 2024/25 capability year. NYISO has identified enhancements to its model for calculating Capacity Accreditation Factors that it plans to implement in subsequent years.

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.H.

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 ("CAFs") relies on its resource adequacy model, GE MARS, which is used to establish the IRM each year. MARS is a Monte Carlo model that simulates hourly load and resource availability under a variety of conditions. Hence, the characteristics represented for each resource type in MARS will affect its CAF. While NYISO's MARS model is a sophisticated tool, it has limitations in modeling the resource types listed below. NYISO's ongoing *Modeling Improvements for Capacity Accreditation* project aims to develop modeling enhancements over the next several years for each of the following resource types.[183]

- *Gas-Only Generators* – NYISO has 9.0 GW of gas-fired generation that is currently without dual-fuel capability, of which only 2.5 GW were supported by firm fuel contracts in Winter 2022-23.[184] During extreme cold conditions, the total supply of fuel to these units is limited, so they are not able to operate simultaneously. Gas supplies in peak

183 Changes to MARS modeling in the IRM study require coordination between NYISO and the New York State Reliability Council (NYSRC). For an overview of NYSRC and NYISO modeling enhancement priorities and planned timelines, see NYISO October 19, 2022 ICAPWG presentation "Capacity Accreditation" and January 26, 2023 presentation "Modeling Improvements for Capacity Accreditation: Project Kick Off".

184 See November 30, 2022 NYISO presentation to NYISO Management Committee "2022-23 Winter Assessment & Preparedness", available here.

winter conditions are especially tight in eastern New York.[185] 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 is currently studying approaches to model joint gas supply limitations.[186]

- *Inventory-Limited Resources* – Oil-fired and dual-fuel generators store fuel on-site and periodically replenish inventories as fuel is consumed. In eastern New York, there is 2.8 GW of oil-fired and dual-fuel capacity with maximum oil inventories that allow less than 3 days of operation, and an additional 3.0 GW with maximum inventories of 3 to 5 days. Analysis by NYISO using its Internal Assessment Model shows that the need for emergency procedures in a prolonged winter cold snap is highly sensitive to whether generators are able to replenish spent oil inventories in a timely manner.[187] MARS currently assumes that oil resources always have available fuel. It is critical to realistically model oil inventories and replenishment capabilities in order to accurately accredit these resources and encourage inventory management practices that support winter reliability. NYISO currently plans to evaluate modeling of winter reliability issues beyond gas pipeline constraints. This evaluation is currently planned to occur in the 2024-2025 timeframe.
- *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. If solar generation and load are not appropriately correlated in the model, solar and other resources will be valued inaccurately. Aligning the modeling of the resource mix and load profiles to reflect common drivers would improve capacity value estimates. NYISO plans to consider this issue in 2026.
- *Energy Storage* – Modeling realistic dispatch of energy limited resources (ELRs) is challenging because it must balance considerations of optimal discharge and limited foresight. NYISO recently adopted an 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.[188] This approach 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

185 See October 20, 2022 MMU presentation "MMU Analysis of Gas Availability in Eastern New York", available here.

186 See February 28, 2023 NYISO presentation to ICAPWG "Modeling Improvements for Capacity Accreditation: Natural Gas Constraints", available here.

187 See November 30, 2022 NYISO presentation to NYISO Management Committee "2022-23 Winter Assessment & Preparedness", slides 27-33, available here.

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

imperfect foresight.[189] 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. NYSRC is studying possible enhancements to the ordering of emergency procedures in 2023 and plans to consider further improvement to ELR modeling in future years.

- *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. NYISO plans to consider modeling enhancements related to startup times in the 2023-2024 timeframe.

Hence, 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) inventory-limited resources, (c) energy limited resources, (d) resources whose availability is correlated with load, and (e) inflexible generators. (see Recommendation #2021-4)

Functionally Unavailable Capacity

NYISO tests the Dependable Net Maximum Capability (DMNC) of each generator on a seasonal basis. This is intended to reflect its maximum output when not experiencing a forced outage or derating during temperature conditions similar to the peak load period of each season. The ICAP that a resource can sell in the capacity market is determined based on the lower of its DMNC and capacity interconnection rights (CRIS) quantity. NYISO currently over-estimates the ICAP of fossil-fuel and nuclear resources with the following characteristics:

- *Emergency Capacity*: Capacity offered above a generator's normal upper operating limit ("UOLn") that is only activated under NYISO Emergency Operations.[190] Operators may not commit this capacity in practice because of concerns that the emergency capacity cannot operate in a reliable manner, thereby increasing the risk of outage to the normal range of the generator's capacity.
- *Ambient Water Temperature Dependent*: Generators that have water-cooled condensers see diminished cooling capability as inlet water temperatures rise. Environmental restrictions also prohibit outlet water temperatures from exceeding certain defined thresholds. Therefore, many of these water-cooled units have reduced capability on hot summer days due to higher water temperatures, which are not captured in the DMNC test.
- *Ambient Air Humidity Dependent*: Combustion turbines that are equipped with certain Inlet Cooling Systems are significantly impacted by increases in the relative humidity in

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

190 See NYISO Emergency Operations Manual.

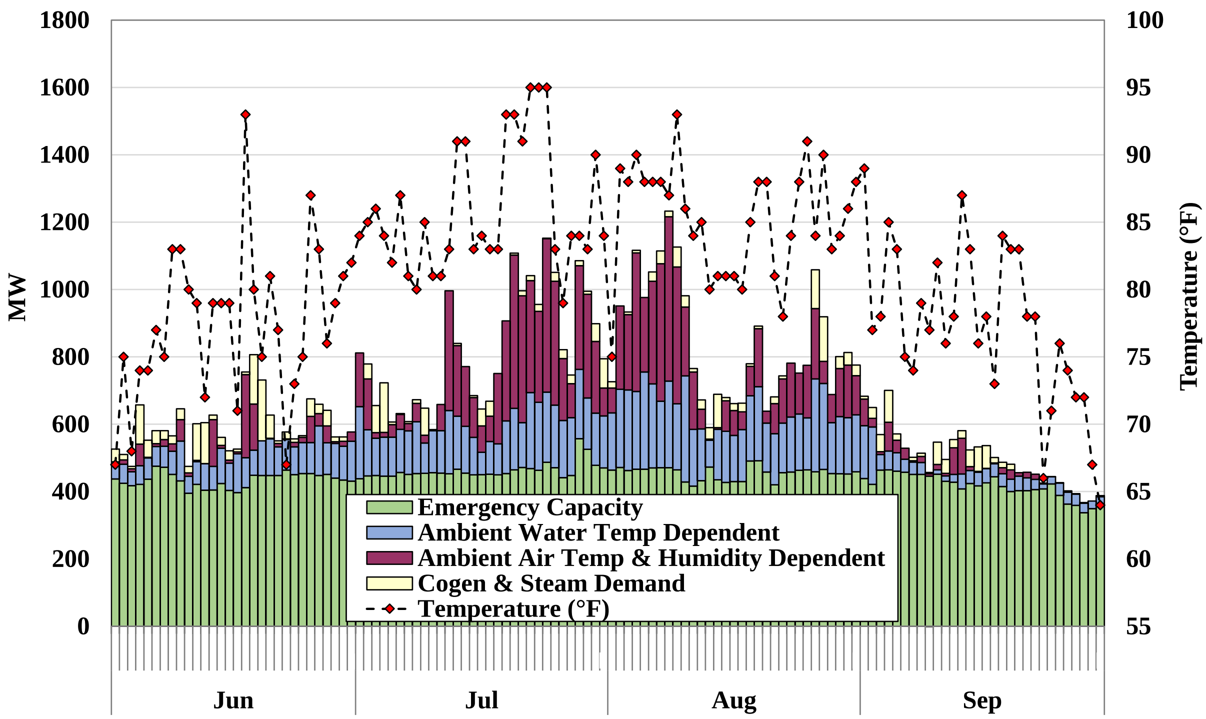
the air. This impact increases as air temperatures rise, compounding this issue. The DMNC test process has no procedure for adjusting for this impact on generator capability.

- *Cogen & Steam Demand*: Some units have reported derates from cogeneration units due to limitations associated with their host steam demand.

Figure 29 shows capacity that was sold in the capacity market in Summer 2022 but that was unavailable in real time for the reasons listed above.[191] Approximately 1,200 MW of ICAP was functionally unavailable on the hottest days. To address this, we recommend that the DMNC testing and ICAP qualification processes be enhanced to: (see Recommendation #2021-4)

- Calculate seasonal capacity ratings that are adjusted for ambient water and humidity conditions (in the procedure that NYISO currently uses to adjust for ambient air conditions) for affected generators, and
- Remove special rules for so-called "Capacity Limited Resources" (CLRs) which allow them to qualify "emergency capacity" that is not required to offer in the day-ahead market.
- Require cogeneration resources to be seasonally rated in a manner similar to Behind the Meter Net Generation ("BTM:NG") resources which takes into account host steam demand during peak load conditions.

Figure 29: Functionally Unavailable Capacity from Fossil and Nuclear Generators
Summer 2022



191 See Section VI.C of the Appendix for details and assumptions underlying this figure.

G. Impact of Transmission Security Limits on Efficient Capacity Payments

The LCR Optimizer employs a minimum 'floor' value in each locality based on the Transmission Security Limit (TSL). The Optimizer is not permitted to produce an LCR below this floor, even if doing so would satisfy the statewide LOLE criterion of 0.1 days per year at lower cost. In recent years, LCRs have increasingly been set at this 'TSL-floor'. When this occurs, the capacity market does not efficiently compensate certain resources that do not contribute to satisfying transmission security needs.

The TSL-floor is enforced in the "LCR Optimizer" to ensure that LCRs do not violate NYSRC/NPCC transmission security criteria, which are designed to ensure that the system remains stable in the event of major contingencies. Transmission security analysis differs from the resource adequacy analysis used by the LCR Optimizer because: (1) transfer limits are calculated more conservatively in the transmission security analysis, and (2) peak load and resource availability are modeled on a deterministic basis as opposed to stochastically.[192] As a result, the amount of capacity needed to comply with transmission security criteria in a locality can exceed the amount needed to satisfy reliability criteria in GE-MARS. In this case, the LCR is set by the TSL-floor.

Some resource types are assumed to contribute less towards transmission security requirements than resource adequacy requirements.[193] In particular:

- Special Case Resources (SCRs) contribute 0 MW towards transmission security requirements because they are assumed to not be available under normal transfer criteria.
- Large resources that are identified as a credible contingency can increase the transmission security requirement. This is because the TSLs are designed to maintain reliability in the event that the largest two generation and/or transmission elements are lost. If a resource is one of the largest two contingencies, transmission security criteria require that its capacity be 'backed up' by an equivalent amount of capacity from other resources. For example, we previously estimated that the 980 MW Ravenswood 3 unit in New York City increased transmission security needs by approximately 215 MW.[194]

NYISO has recently made changes to the calculation of the TSL-floor used in the LCR Optimizer to align it with the transmission security methodology used in its Reliability Planning

192 For example, in the 2023 LCR Case, the MARS transfer limit between zones I and J was 4,400 MW, but the Zone J transmission security limit was 2,875 MW. For a detailed discussion of the differences between transmission security and resource adequacy analyses, see NYISO June 30, 2021 presentation to ICAPWG "Transmission Security Best Practices", available here.

193 See our review of NYISO's 2022 Reliability Needs Assessment (RNA), available here.

194 See our review of NYISO's 2020 Reliability Needs Assessment (RNA), available here.

Process.[195] The current methodology, which was used for the first time in the 2023/24 LCR Report, determines the TSL-floor as the local installed capacity needed to meet peak load considering resource unavailability based on expected forced outage rates while respecting the TSL. Since SCRs sold in the capacity market do not contribute to satisfying transmission security criteria, the current methodology raises the TSL-floor to account for the amount of expected SCR capacity sales in the locality.

Figure 30 illustrates the impact of recent changes in the TSL methodology. It compares the final LCRs and TSL-floors in the New York City locality for the 2019/20 through 2023/24 capability years, along with estimated TSL-floors for the 2025/26 and 2026/27 capability years. The impact of the Ravenswood 3 unit on the TSL-floor is shown in all years. The impact of SCRs on the TSL-floor is shown beginning in 2022, when the TSL-floor calculation was first affected by the amount of SCR sales.[196] The expected impact of the planned Champlain Hudson Power Express (CHPE) transmission line on the TSL-floor is shown in 2026. The 1,250 MW CHPE project is expected to increase the TSL-floor by 532 MW because it will be the largest contingency in New York City.[197] We also show the projected value for the 2025/26 LCR if set by the LCR Optimizer, based on a study performed by NYISO in 2022 which assumed a lower level for the TSL-floor that was not binding.[198]

Figure 30 illustrates that the TSL-floor is increasingly likely to determine the New York City LCR. After adoption of the current methodology in 2022, the NYC LCR was set at its TSL-floor for the first time for the 2023/24 capability year. Our projected 2025/26 TSL-floor of 81.6 percent significantly exceeds NYISO's Optimizer-based projected LCR of 77.6 percent. After the CHPE line enters service, our projected 2026/27 TSL-floor further increases to 86.4 percent. Binding TSL-floors lead to higher consumer costs by requiring a larger amount of capacity to be held in higher-priced localities.

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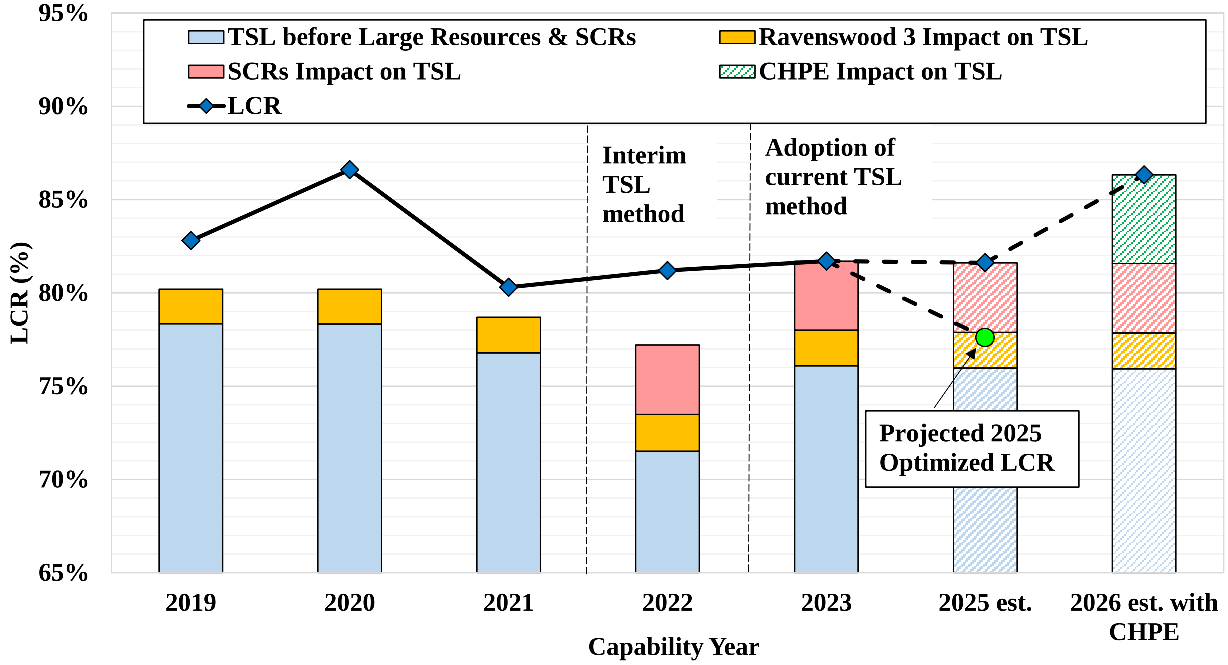
195 See NYISO October 4, 2022 presentation to ICAPWG "Transmission Security Limit Calculation: 2023 LCR Study", available here.

196 In the 2022/23 capability year, NYISO employed an "interim methodology" that added back the capacity of SCRs when calculating the TSL-floor but did not convert the UCAP needed to meet peak load while respecting the TSL into an ICAP quantity. Beginning in the 2023/24 capability year, NYISO began to calculate the TSL-floor in ICAP terms, resulting in an increase relative to the interim methodology.

197 See Figures 78-84 in Appendix F to NYISO's 2022 RNA, available here, and our review of NYISO's 2022 Reliability Needs Assessment (RNA), available here.

198 See March 25, 2022 NYISO presentation to ICAPWG "AC Transmission and Peaker Retirements in IRM Study", available here. This study was not primarily intended to examine the impacts of TSLs and used a constant 77.2 percent TSL-floor in New York City for all future years, based on the final 2022/23 TSL. Note that the projected LCRs from this study were developed based on information available at the time and are certain to change as the future capability year approaches.

Figure 30: Historical and Projected New York City LCRs and TSLs



Large resources and SCRs are overcompensated when the LCR of their locality is set at its TSL-floor. This is because the presence of these resources causes the TSL-floor to increase, so they provide less net supply towards meeting capacity requirements than they are paid for in the capacity market. This results in (1) higher consumer costs because these resources are paid more than the value they provide, and (2) inefficient investment incentives, such as for SCRs to convert to NYISO's DER resource type, which has different requirements and provides more value towards transmission security needs. In the upcoming 2023-24 capability year, we estimate that large resources and SCRs in New York City could be overcompensated by up to $52 million.[199]

Hence, we recommend paying resources the highest capacity price among requirements which they contribute to meeting (Recommendation #2022-1):

- SCRs should be compensated at the price that would prevail in their locality absent the TSL-floor. This will require the NYISO to determine what the LCR would be if there was no TSL requirement so that it can determine a resource's contribution to satisfying resource adequacy needs.[200]

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199 This value reflects an upper-bound overpayment assuming that New York City capacity requirements would fall by the reduction in TSL if SCRs and large resources did not cause it to increase. We apply the corresponding difference in projected capacity prices to 377 MW summer and 196 MW winter SCR UCAP (based on recent auctions) and 215 MW of capacity from Ravenswood 3 that causes an increase in the TSL-floor.

200 Note that the addition of SCRs may also cause the NYCA IRM and Optimizer-determined LCRs to increase because SCRs are not available at all times. This affects SCRs' capacity payments through the Capacity

- Large resource that increase the size of the contingency used to determine the TSL-floor should be compensated at two rates: the full capacity price for the portion of their capacity that does not cause the TSL-floor to increase, and the capacity price that would prevail absent a TSL-floor for the rest of their capacity.

These changes would cause SCRs and large resources to be appropriately compensated based on their contributions to resource adequacy requirements. Payments to these resources would be unaffected when LCRs are not set at the TSL-floor.

H. 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.[201] The Appendix of this report analyzes how FCTRs might affect a transmission investment decision.[202]

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 (see Section IV.A)

Accreditation Factor (CAF). NYISO plans to examine changes needed to accurately determine the SCR CAF as part of the Modeling Improvements for Capacity Accreditation project currently underway.

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

202 See Appendix Section VI.G for additional details.

I. Assessment of Seasonal Capacity Market Framework

The capacity market was designed to procure sufficient resources to enable NYISO to satisfy demand reliably during summer peak conditions. It has been taken for granted that this design would also make sufficient resources available to satisfy demand at other times of the year. However, the evolving supply mix and demand patterns will require NYISO to reform the capacity market to avoid reliability issues during peak winter conditions. In the long-term, additional reforms may be needed to maintain reliability during extended periods of low intermittent production during shoulder seasons. Subsection F discusses the need for better capacity accreditation to account for differences in resource availability (e.g., due to natural gas availability) between summer and winter conditions. This subsection discusses the need for additional capacity market reforms to address winter reliability needs more efficiently.

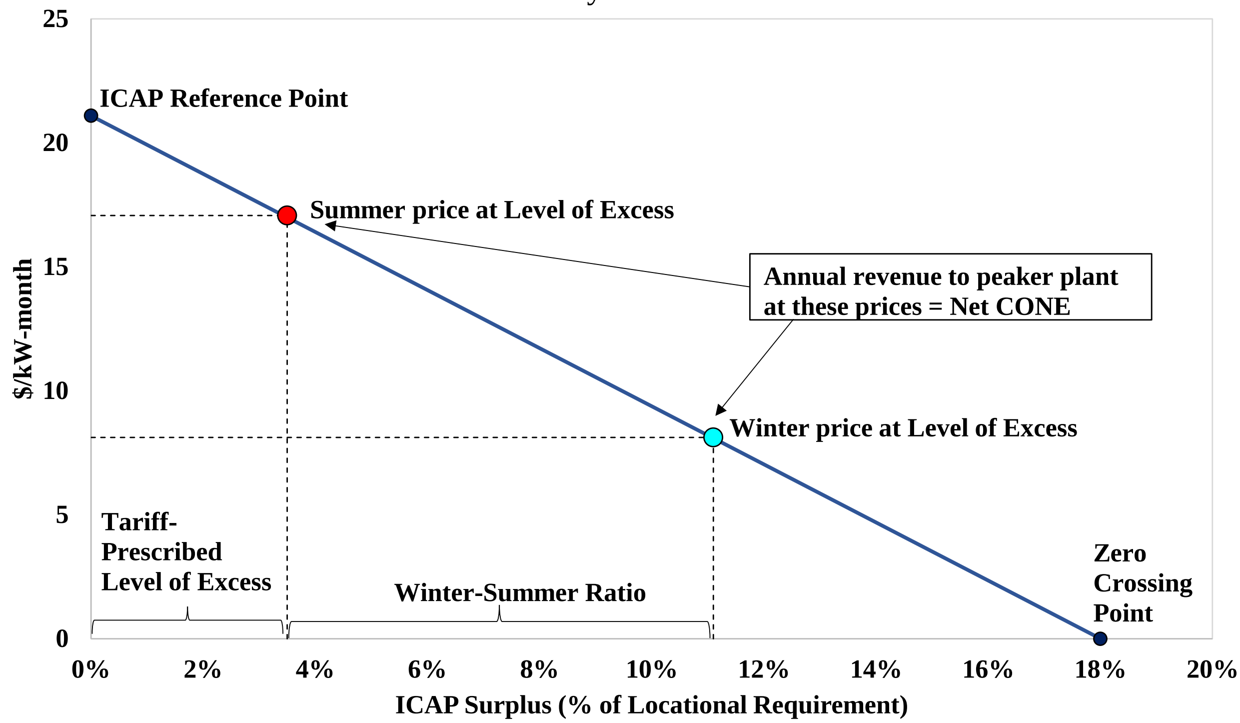
The capacity market is divided into Summer and Winter Capability Periods of six months each. The Installed Reserve Margin (IRM) and Locational Capacity Requirements (LCRs) are determined annually, resulting in ICAP Requirements that are the same in all months of a capability year. The level of surplus in each monthly spot auction is determined by the amount of participating ICAP supply relative to this annual requirement.

NYISO sets ICAP Demand Curves by choosing the Reference Point that will cause the reference peaker technology to earn its Net Cost of New Entry (Net CONE) over the course of the year when the amount of surplus is equal to the tariff-prescribed level of excess (LOE).[203] This calculation considers the ratio of winter ICAP to summer ICAP (the "winter-summer ratio"), because prices in the season with more ICAP supply (historically, winter) will be lower when both seasons employ the same ICAP demand curve. Figure 31 illustrates these concepts.

Setting seasonal prices based on the level of ICAP supply relative to an annual requirement does not accurately reflect the balance of reliability risk between seasons. This is because factors other than total ICAP affect reliability. These factors include peak load in each season and suppliers' *availability* in that season, which differs from their ICAP ratings. For example, a gas-fired generator that lacks firm fuel supply is less available in winter than in summer, but its winter ICAP rating is likely to be equal to or higher than its summer ICAP rating (considering temperature effects on maximum capability).

[203] The tariff-prescribed LOE is the requirement in each zone plus the capacity of the peaker technology.

Figure 31: Seasonal ICAP Prices in Current Demand Curve Construct
2023/24 New York City Demand Curve Parameters



Hence, the current construct will not provide adequate signals to build and maintain resources with season-specific reliability attributes. For example, under the current demand curve construct, summer prices will exceed winter prices even if reliability risk is concentrated in winter, as long as winter supply exceeds summer supply in ICAP terms. A lack of capacity market signals that correspond to seasonal needs may lead to premature retirement of resources needed for season-specific reliability and weak incentives to attract price-sensitive imports when needed. The balance of seasonal reliability risk is evolving due to changes in load and the resource mix, as well as planned improvements to modeling of gas-dependent winter generators. It is important for capacity price signals to keep pace with changes in system needs.

NYISO has recently proposed updates to the ICAP demand curves that would establish separate reference point values in summer and winter, corresponding to the proportion of reliability risk in each season in the IRM study.[204] This proposal would improve the alignment of capacity prices with seasonal reliability risk when the system is at the tariff-prescribed level of excess. However, all months of the year will continue to use the same ICAP requirements and prices will continue to be set based on the level of ICAP supply relative to those requirements. As the system's seasonal needs evolve, this could lead to the following market problems:

204 See section on "ICAP Demand Curve Reference Point Price Proposal" in February 21, 2023 NYISO ICAPWG presentation "2025 - 2029 ICAP Demand Curve Reset", available here.

- Adjusting demand curves based on the ICAP winter-summer ratio could lead to excessively steep demand curves under some circumstances, resulting in unnecessary price volatility and market power concerns;
- Demand curves may not provide adequate signals to maintain reliability when conditions differ from the assumptions of the IRM study; and
- Changes in the proportion of winter and summer reliability risk in the IRM study could cause large arbitrary changes in annual capacity revenues at surplus levels other than the tariff-prescribed level of excess.

In addition to these issues, the schedule for determining capacity market parameters may fail to adequately incentivize resources to take actions to promote winter reliability. Assumptions regarding the status of generators in the IRM base case are typically finalized in the fall before the corresponding May-April capability year. Hence, assumptions regarding winter suppliers will be locked in over a year before the key December – February winter months. Generators that must decide whether to contract for firm fuel deliveries in these months may be unable to do so economically over a year in advance. As a result, the market may establish ICAP requirements and capacity accreditation values in a way that limits opportunities for gas-fired generators to profitably enhance reliability by demonstrating firm fuel contracts.

Hence, we recommend that NYISO move to a seasonal capacity market framework.[205] This approach would establish requirements and demand curves that consider the reliability needs of each season separately, so that prices are not distorted by relative ICAP values between seasons. A seasonal capacity market would include the following:

- Establish seasonal requirements that reflect the amount of capacity needed to satisfy the targeted level of reliability in each season, considering generator availability and load;
- Set demand curves such that annual compensation to the demand curve technology approaches its Net Cost of New Entry as surplus supply approaches the Level of Excess in any season; and
- Consider establishing or updating the winter capacity requirements closer to the winter season so that any changes in resource status and fuel procurements can be accurately incorporated in requirements and resource accreditation values.

[205] See Recommendation #2022-2 in Section XII.

IX. 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.[206] 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 upstate regions (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 15 summarizes the net scheduled imports from neighboring control areas from 2017 through 2022 during peak (i.e., 6 am to 10 pm, Monday through Friday) hours.[207]

Table 15: Average Net Imports from Neighboring Areas
Peak Hours, 2017 – 2022

Year	Quebec	Ontario	PJM	New England	CSC	Neptune	1385	VFT	HTP	Total
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
2022	1,137	471	459	-392	217	483	62	275	376	3,088

206 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 operated under the M2M JOA with PJM in real-time. This line is further evaluated in Section VI.E and Appendix Section VI.C.

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

In 2022, average total net imports from neighboring areas was approximately 3.1 GW in peak hours. This represents a decrease of 5 percent from the previous year. However, despite the modest decrease, imports still served a significant portion (17 percent) of NYISO load in 2022.

Controllable Interfaces

On Long Island, net imports from neighboring control areas satisfied nearly 33 percent of demand in 2022, which was 5 to 6 percent higher than the levels recorded in 2020 and 2021 when transmission outages reduced imports significantly. The Cross Sound Cable experienced lengthy outages in the second half of 2020, and the Neptune line was partially available from September 2020 through June 2022.

In New York City, net imports over the HTP and Linden VFT lines contributed a total of 650 MW during peak hours in 2022, satisfying 11 percent of the demand. Imports over the HTP line increased in 2022 with the highest levels observed in the winter months when regional gas price spreads were largest, making PJM generation more economic relative to NYISO generation. Additionally, due to lengthy transmission outages, flows to eastern New York across the Central-East Interface were reduced, leading to higher energy prices in Eastern New York and attracting more imports from PJM. The two factors have contributed to higher net imports to NYC from the controllable lines over the past two years compared to the levels recorded prior to 2021.

Primary Interfaces

Average net imports from neighboring areas across the four primary interfaces fell 17 percent from 2021 to 1,675 MW in 2022 in peak hours. This decrease was largely due to reductions in imports from both Canadian control areas and PJM, although reduced exports to New England helped to offset some of the overall reduction. This decrease also represented the lowest import level observed in the past six years, except for the unusually low values seen in 2020.

Among the primary interfaces, the Quebec interface continued to account for the largest share of the net imports, representing 68 percent in 2022. Average net imports from Quebec consistently ranged between 1,140 MW and 1,370 MW in each year from 2017 to 2022, with high utilization of the lines. Variations in Quebec import levels were largely driven by transmission outages on the interface.[208] Moreover, the winter of 2022 was colder than in previous years, leading to seasonal reductions in imports from Quebec, which is a winter-peaking region.

Net imports across the primary interfaces with PJM, New England, and Ontario have shown more variations over the last six years. Net interchanges with PJM and New England have

208 For example, the interface was out of service for one week in April, and one of the DC poles on the interface was out of service from early May to early June and from early October to early November. The import levels fell in accordance with the reduced interface limit during these outages.

largely followed the changes in gas price spreads between these regions. For example, in the winter, New York normally imports from PJM and exports to New England, consistent with the gas price spreads between markets during this season (i.e., New England > New York > PJM). These variations in net imports reflect the complex interactions between electricity and natural gas markets, as natural gas is a crucial fuel for power generation, particularly in the Northeast region.

Transmission outages continued to affect interchange with these regions in 2022. In particular, lengthy major transmission outages reduced the transfer capability from west to east in New York, reducing incentives to import to western New York. As a result, net imports from Ontario continued to fall in 2022. Furthermore, the transmission work related to the Beck Project at the border often reduced the interface transfer capability, contributing to lower imports from Ontario. Higher congestion across the Central-East interface has also made it more costly to export to New England, resulting in reduced export levels to that region.

B. Unscheduled Power Flows in Upstate Regions

Unscheduled power flows (i.e., loop flows) have significant effects on power flows in New York. When loop flows occur, it can increase congestion in certain areas of the transmission system, causing market inefficiencies and potentially leading to increased costs for consumers.

Loop Flows around Lake Erie

Loop flows that move in a clockwise direction around Lake Erie 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.[209] There was a strong correlation between the severity of West Zone congestion and the magnitude and volatility of loop flows in 2022.[210]

The NYISO has implemented several market enhancements in recent years to enhance congestion management in the West Zone and limit the impact of loop flows. These include: (a) incorporating 115 kV constraints in the day-ahead and real-time markets and improving modeling of the Niagara Plant in December 2018; (b) incorporating 115 kV constraints into the NYISO-PJM M2M JOA process in November 2019; (c) relocating the electrical location of the

209 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.

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

IESO proxy bus in April 2020;[211] (d) using a higher CRM of 60 MW on the Niagara-Packard 230 kV lines and the Niagara-Robinson Rd 230 kV line;[212] and (e) using a more conservative assumption in RTC regarding loop flows.[213]

In addition, the Empire State Line Public Policy Transmission project was completed before summer 2022, further alleviating congestion in the West Zone and making it less vulnerable to the impact of loop flows. As a result, although average loop flows in the clockwise direction increased from 2021 to 2022, the West Zone congestion fell by nearly 50 percent.

Loop Flows between Upstate NY and NE

Although the impact of loop flows around Lake Erie on West Zone congestion has decreased, loop flows at the border between NY and NE became more impactful on transmission constraints from Capital to Hudson Valley in 2022. This was due largely to lengthy transmission outages required to support the construction work of Public Policy Transmission Project Segment A and Segment B, which reduced transfer capability on this corridor and made it more susceptible to the impact of loop flows in real-time.

The Cricket Valley-Pleasant Valley 345 kV constraint ("the Cricket-PV constraint") accounted for most of Capital to Hudson Valley congestion in 2022, and was particularly susceptible to the impact of loop flows at the NY and NE border. Figure 32 summarizes the differences in unmodeled flows on the Cricket-PV constraint between RTD and RTC and the resulting price impact on select locations in 2022.[214]

Real-time congestion on the Cricket-PV constraint occurred in 16 percent of intervals in 2022, with most of the incidents happening during the summer months. The figure shows that, at the NY/NE proxy bus, the difference of unmodeled flows on the Cricket-PV constraint between RTC and RTD resulted in RTC prices being higher than RTD prices by an average of $4.05 per MWh in these intervals. This led to uneconomic imports from New England scheduled at the RTC prices, undermining the overall efficiency of the CTS process. Therefore, it would be beneficial to consider enhancing modeling of loop flows between NY and NE to more accurately reflect the effects of expected variations. The expected installation of the Dover PARs at the end of 2023 should help reduce the magnitude of loop flows at the NY and NE border.

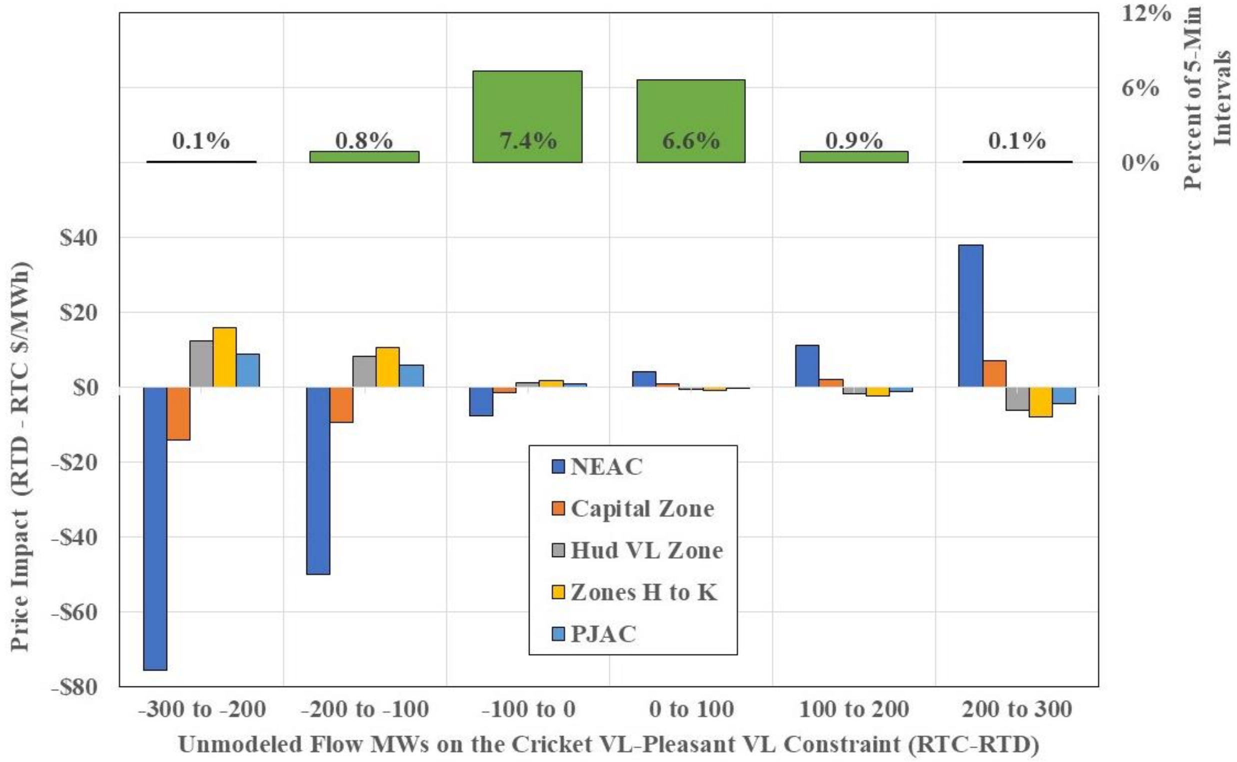
211 In April, 2020, the NYISO relocated the electrical location of the IESO proxy bus in its scheduling models from the Bruce 500 kV station to the Beck 220 kV station (near the Niagara station in New York), which provides a more accurate representation of the effects of interchange with Ontario on loop flows.

212 This is much higher than the default 20 MW that is used for most of other constraints.

213 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.

214 See Figure A-84 in the Appendix for a more detailed description of the chart.

Figure 32: Differences Between RTC and RTD Prices and Unmodeled Constraint Flows
Cricket-PV Constraint, 2022



In addition to the effects of loop flows on congestion in the West Zone and from Capital to Hudson Valley, 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 VII.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.

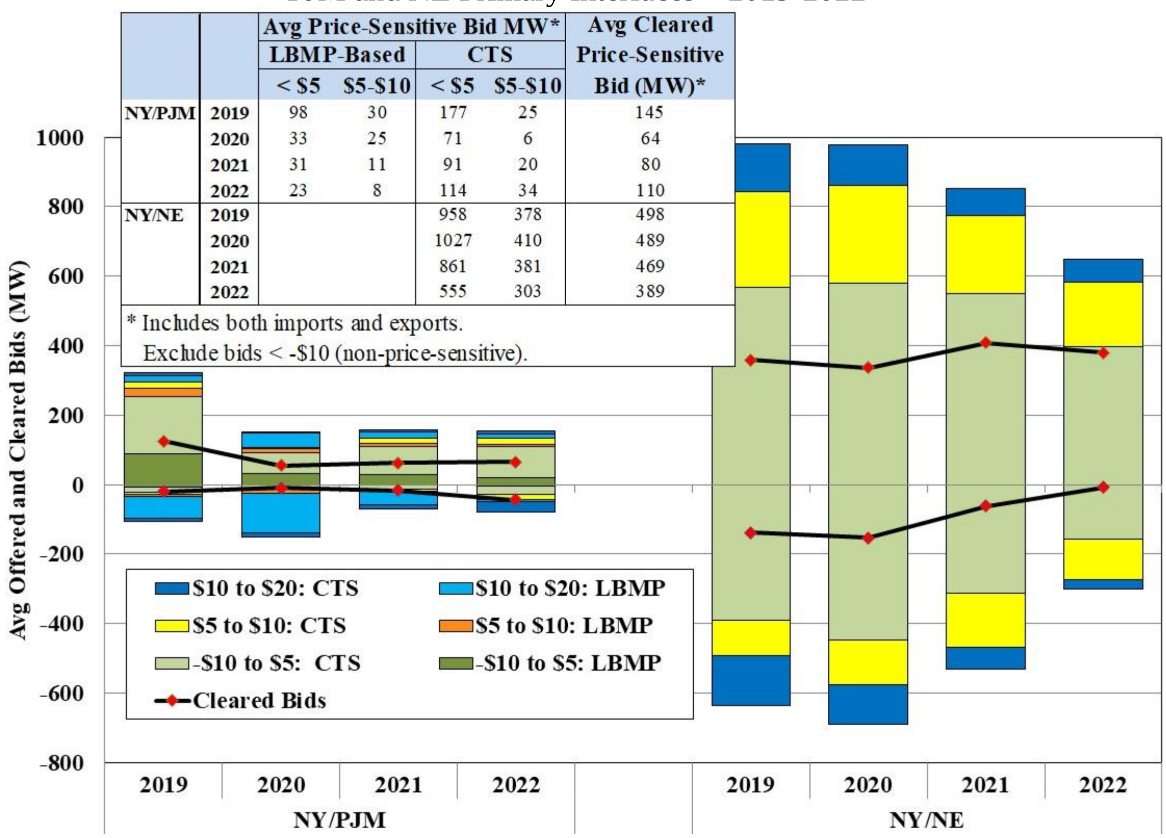
It is important to evaluate the performance of CTS on an on-going basis to ensure that the process is working as efficiently as possible. In this subsection, we discuss several factors that have affected CTS performance at the PJM and ISO New England interfaces, particularly the effects of transaction fees and short-term price forecasting. We also provide a detailed analysis of factors that contribute to poor short-term price forecasting.

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 33 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 2019 to 2022.[215] 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.[216]

Figure 33: Average CTS Transaction Bids and Offers

PJM and NE Primary Interfaces – 2019-2022



		Avg Price-Sensitive Bid MW*				Avg Cleared Price-Sensitive Bid (MW)*
		LBMP-Based		CTS		
		< $5	$5-$10	< $5	$5-$10	
NY/PJM	2019	98	30	177	25	145
	2020	33	25	71	6	64
	2021	31	11	91	20	80
	2022	23	8	114	34	110
NY/NE	2019			958	378	498
	2020			1027	410	489
	2021			861	381	469
	2022			555	303	389

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

215 Figure A-72 in the Appendix shows the same information by month for 2022.

216 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.

The average amount of price-sensitive bids at the PJM interface was significantly lower than at the New England interface in each year from 2019 to 2022. An average of roughly 1220 MW (including 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 200 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 more than 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, very few 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.[217] These charges are a significant economic barrier to achieving the potential benefits from the CTS process at the PJM border.

Figure 34 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 2018 to 2022.[218] [219] The gross profitability of scheduled real-time transactions (including both imports and exports) averaged roughly $0.39 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.

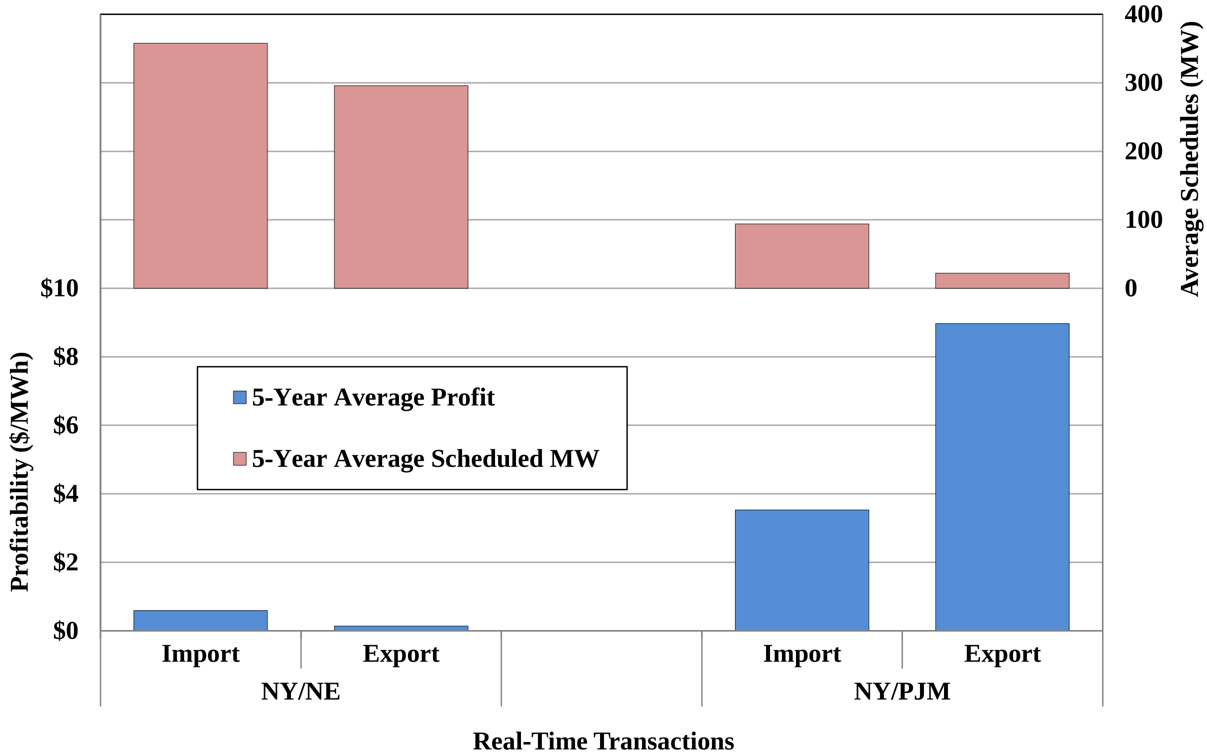
At the PJM border, scheduled imports had a significantly higher average gross profitability, while scheduled exports had an even higher profitability. This reflects that market participants only schedule transactions when they expect the price spread between markets to be large enough to recoup the fees that they will have to pay. Consequently, they schedule much lower quantities, particularly for exports from NYISO to PJM, which are subject to 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.

217 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.

218 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).

219 This chart excludes data from December 23 and 24, 2022 because a large amount of external transactions were curtailed by operators on the two days to manage system reliability and the CTS process was also suspended for most of hours on December 24.

Figure 34: Gross Profitability and Quantity of Scheduled Real-Time External Transactions
PJM and NE Primary Interfaces, 2018-2022



We recommend eliminating (or at least reducing) these charges at the interfaces with PJM for several reasons.[220] 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 $2.4 million in export fees from real-time exports to PJM in 2022, while PJM collected $2.9 million in export fees from real-time exports to NYISO. Thus, it is possible that a lower export fee would result in an overall higher collection of fees because it would allow CTS transactions to be profitable under a wider range of conditions.

220 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.[221]

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 2022, this adjustment (from our estimated hourly schedule) occurred in 89 percent of intervals at the New England interface, compared to 59 percent at the PJM interface. However, inaccurate price forecasts reduced the savings that were actually realized. We estimated that in 2022,[222]

- $14.7 million of savings were realized at the New England interface; and
- $0.2 million were realized at the PJM interface.

In 2022, the actual production cost savings at the New England interface increased compared to 2021 because of the larger disparities in energy prices between the markets, which was partly driven by increased regional gas price spreads. However, the actual production cost savings at the PJM interface remained comparable to 2021, and significantly lower than at the New England interface, which has been a persistent trend in recent years, partly attributable to 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 2022. 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

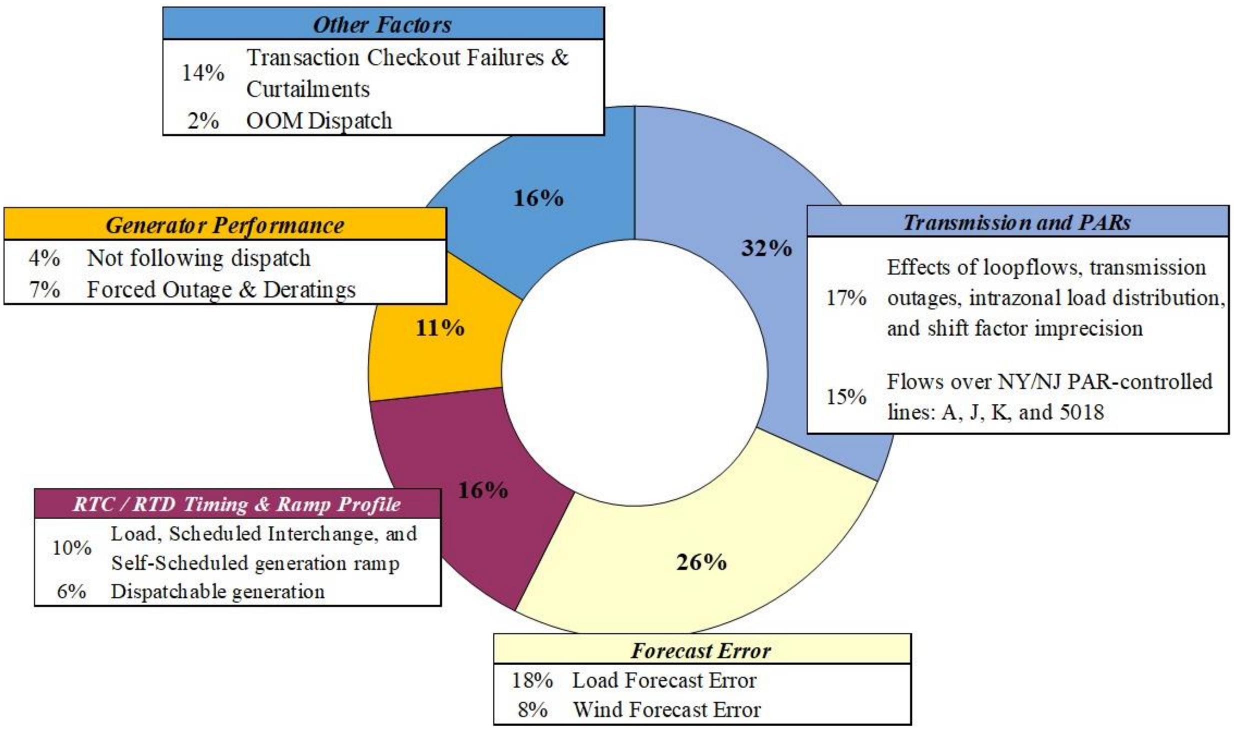
221 Section IV.C in the Appendix describes this analysis in detail.

222 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.[223] We expect that this evaluation will be useful as the NYISO and stakeholders prioritize different projects to improve market performance.

Figure 35 summarizes the RTC/RTD divergence metric results for “detrimental” factors (i.e., factors that cause or contribute to differences between RTC and RTD) in 2022.[224] Our evaluation identified that the factors that contributed most to RTC price forecast errors in 2022 were mostly consistent with prior years. However, there was a marked increase in RTC/RTD divergence in 2022 due to transaction curtailments.[225] We discuss each of these factors in more detail below.

Figure 35: Detrimental Factors Causing Divergence Between RTC and RTD
2022



First, transmission network modeling issues were the most significant category, accounting for 32 percent of the divergence between RTC and RTD in 2022, lower than the 41 percent in 2021. 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

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

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

225 See Section IV.D in the Appendix for a detailed discussion of “detrimental” and “beneficial” factors.

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.

- 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 also large contributors to price differences between RTC and RTD, accounting for 26 percent of the overall divergence between RTC and RTD in 2022.[226] Although the contribution of the load forecast error fell modestly from the level recorded in 2021, it remained high compared to previous years. During the period from hour 10 to hour 18, the average RTC forecasted load was 105 MW higher than average RTD load, contributing to a $4.70 per MWh difference between average RTC LBMPs and RTD LBMPs during the same period.[227] The operator's adjustments to the RTC load forecast were a significant driver of the load difference between RTC and RTD and became more frequent in 2022 partly because the accuracy of Behind the Meter ("BTM") solar forecasts has decreased. Although the frequency and magnitude of these load adjustments decreased in the second half of 2022,[228] it is important to continuously evaluate the current procedure for determining load forecast adjustments in RTC to identify any potential areas for improvement.

Third, the next largest category, which accounted for 16 percent of the divergence between RTC and RTD prices in 2022, 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).[229] We have recommended improving the consistency between the ramp assumptions used in RTC and RTD.[230]

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226 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.

227 See Figure A-83 in the Appendix for more details.

228 See our 2022-Q3 SOM report.

229 Appendix Section IV.E shows the ramp profiles assumed by RTC and RTD for external transactions.

230 See Recommendation #2012-13.

Fourth, external transaction curtailments and checkout failures accounted for 14 percent of detrimental factors to RTC/RTD price convergence in 2022, much higher than the 2 to 4 percent observed in previous years. Curtailments and checkout failures became more frequent in 2022 when 1,100 hours were affected by at least 100 MW compared to only 600 such hours in 2021.[231] We made several observations about the increased curtailments in 2022:

- The Ontario interface accounted for 300 hours in each year with most occurring when transactions were scheduled with NYISO but did not submit a bid priced high enough to clear in the Ontario market.
- The January and December cold spells accounted for more than 40 percent of all curtailment hours in 2022.[232]
  - On the five days during the January cold spell, transaction cuts through the TLR process were frequent, largely affecting imports from PJM when Lake Erie Circulation exceeded the capability of the Ontario-Michigan PARs and caused congestion on Ontario flow gates.
  - During the December 23 & 24 cold spell, transaction curtailments were mostly made by neighboring areas to maintain their own system reliability.[233] CTS was suspended on December 24 to reduce the amount of imports being curtailed after the RTC evaluation of whether to commit fast-start units.

In many cases, curtailments simply lead RTD to increase production from internal generation at a modest additional cost. However, in tight conditions, RTC may schedule low-cost imports and consequently pass on the opportunity to commit peakers. If the import is subsequently curtailed by the neighboring control area, it sometimes requires NYISO to deploy more-expensive peakers that are available on short notice and/or go short of contingency reserves if resources are not available on short notice. It would be useful to consider ways to ensure that NYISO does not rely on imports that are likely to curtailed after the RTC evaluation. Relying on such curtailable imports might be reasonably economic when NYISO has the operating reserves to cover a curtailed import, but not when the curtailment would lead to NYISO reserve shortages.

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. Furthermore, the resource mix of New York is changing away from traditional fossil-fuel generation towards: (a) intermittent renewable generation that will increase uncertainty of resource availability in real time, and (b) new types of peaking generators and energy storage resources that must be deployed based on a short-term forecast of system conditions. A better-performing RTC will more efficiently schedule flexible resources in response to rapid changes in system conditions, which is critical for successful integration of renewable generation.

231 See Figure A-85 in the Appendix.

232 See Figure A-86 in the Appendix.

233 See Section II.G for more discussions on the curtailments during the December cold spell.

X. 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 2022 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.

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.

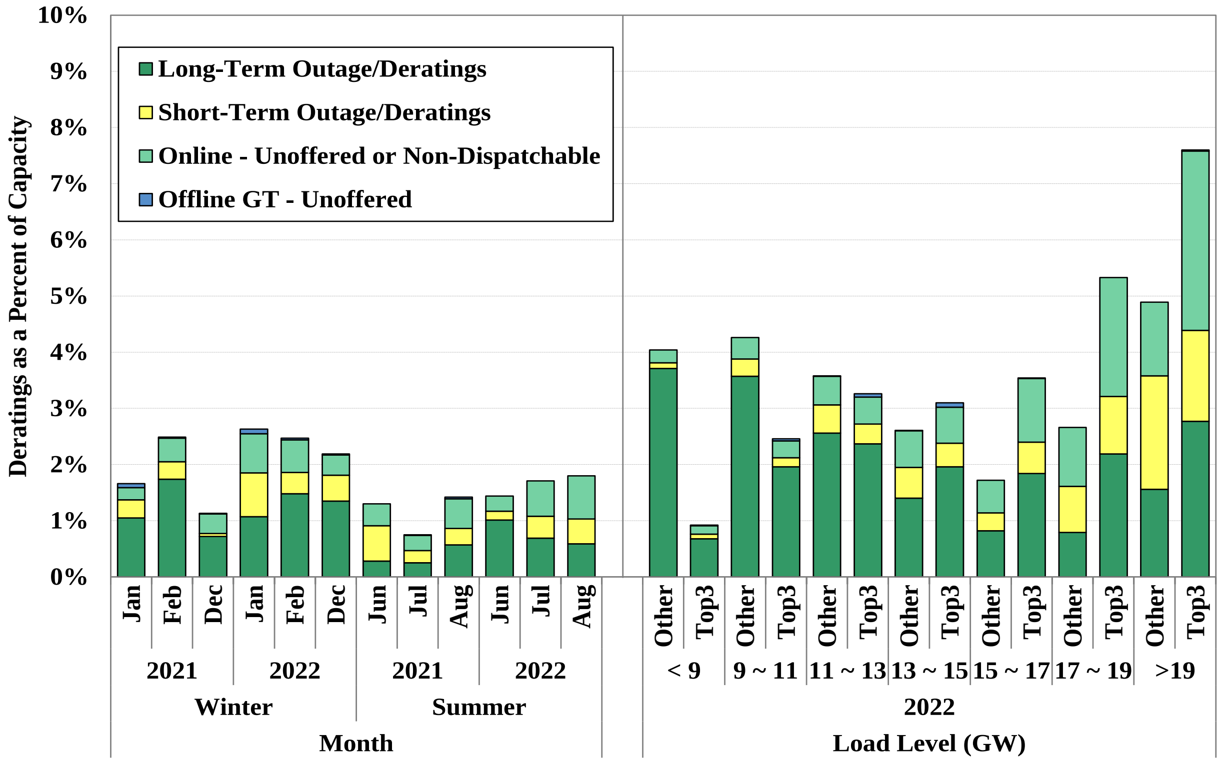
The "supply curve" for energy is relatively flat at low and moderate load levels and steeper at high load levels, which causes prices to be more sensitive to withholding and other anticompetitive conduct under high load conditions. Conditions arise when the supply cost curve becomes steep during periods of low and moderate demand, which could make such periods susceptible to potential anticompetitive conduct as well. 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 and is most susceptible to limitations on natural gas supply during peak winter periods.

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.[234] Figure 36 and Figure 37 show the two potential withholding

[234] 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. Threshold 1 is the 25 percent of the reference level, and Threshold 2 is 100 percent of the reference level. In periods of high fuel prices, Threshold 2 may become greater than the Mitigation Threshold if the applicable reference level cost exceeds $100 per MWh.

measures by season, load level, and the supplier's portfolio size.[235] Generator deratings and outages are shown according to whether they are short-term (i.e., up to seven days) or long-term.

Figure 36: Unoffered Economic Capacity in Eastern New York
2021 – 2022



Overall levels of unoffered economic capacity remained low in 2022, similar to prior years. However, there was a discernable trend of higher unoffered capacity as loads surpassed 17 GW in Eastern NY among all categories in our analysis.

The figure shows that the top suppliers in Eastern New York exhibited higher levels of long-term outages during moderate load conditions (9 to 15 GW). This was primarily associated with seasonal outages spanning the shoulder months that overlapped with some periods of moderate load conditions.

The amount of unoffered economic capacity increased as load levels in the east rose above 17 GW. Roughly 5 percent of economic supply was unavailable from the smaller portfolios during the highest load hours (greater than 19 GW) and more than 7.5 percent of economic supply was unavailable from the Top 3 suppliers. Reduced transfer capability along the Central-East Interface due to Public Policy related transmission upgrades contributed to frequent and high

235 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.

congestion into Eastern NY throughout the year. This congestion led to higher run hours for historically low capacity factor units, especially during peak load conditions. Consequently, the increased reliance on aging, low-capacity factor generators downstate was a significant contributor to the increased unoffered economic capacity identified in this analysis.

During these hours, approximately 3 percent (i.e., a quarter of the four percent of total unoffered economic capacity) of unoffered economic capacity 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.[236] The NYISO's *Improve Duct-Firing Modeling* project is slated to develop a market design in 2024 to address some of these issues.
- *Ambient temperature conditions* – Capacity ratings for temperature-dependent resources change daily, or, in many cases, hourly, based on changes to several ambient factors. Most prominent among these ambient conditions that may reduce generator capability are air temperature, relative humidity, and inlet water temperatures. NYISO currently accounts for air temperature by unit-specific output factor curves that adjust daily for ambient air temperatures. However, this process does not account for humidity and inlet water temperatures, which have significant impact on the capability of generators with certain inlet cooling systems and water cooled condensers.[237] The NYISO's *Modeling Improvements for Capacity Accreditation: Correlated Derates* project is tasked with addressing these concerns with an approach expected in the second half of 2023.
- *Inability to follow basepoint* – Many older, smaller combined cycle generators upstate never installed the necessary equipment to follow 5-minute dispatch instructions from NYISO automatically. Consequently, these units usually do not offer flexibly in real-time when committed. While some generators might make the necessary capital improvements to follow dispatch automatically, it is not cost-effective for some generators.
- *Cogeneration steam demand* – A number of cogeneration resources in Eastern New York sell steam under bilateral contracts and sell excess electric generation to the grid. When host steam demand rises intraday, serving steam load usually takes priority over selling electricity to the grid, leading to derated capability from these resources.

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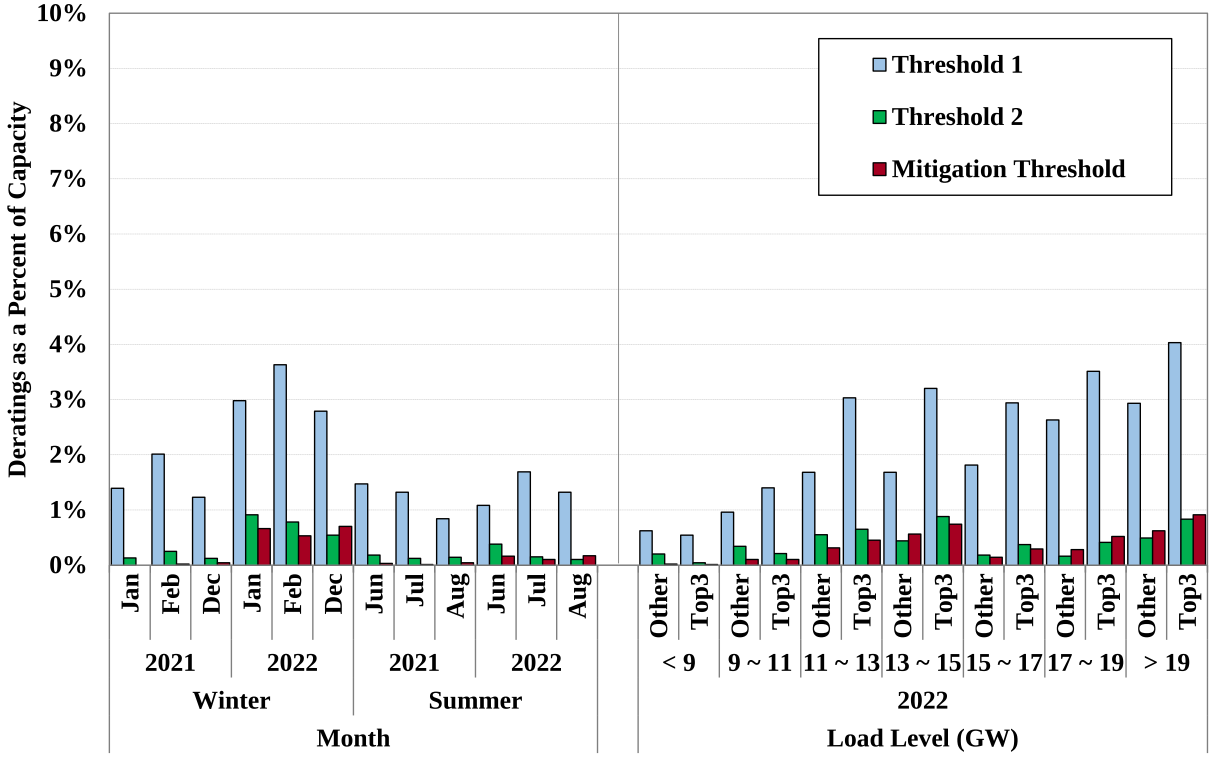
236 Analysis of the affected capacity is provided in Section VI.C.

237 Analysis of the affected capacity during the summer is provided in Section VIII.F.

Figure 37: Output Gap in Eastern New York
2021 – 2022



The amount of output gap in Eastern New York remained very low in 2022, averaging 0.2 percent of total capacity at the statewide mitigation threshold and 1.7 percent at the lowest threshold evaluated (i.e., 25 percent above the Reference Level).

The output gap in Eastern New York is usually largest during high load conditions in summer or in peak winter conditions when fuel prices become volatile. In 2022, the summer and winter experienced periods of high weather-driven load coupled with high and volatile natural gas prices. Consequently, the amount of output gap flagged at the Mitigation Threshold was noticeably higher during both the peak winter and peak summer months than has been the case for many years.

Much of the output gap in 2022 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.[238] 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.

238 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

Two additional factors contributed to the increase in output gap in 2022:

- *Offering Generation with Inflated Physical Bid Parameters*: Certain generators offer Start-up Notification Time ("SUNT") values that exceed their unit's apparent capabilities. In some cases, this may lead a unit that would have been economic to be unavailable for commitment in the day-ahead market. Physical bid parameters are not subject to automated mitigation, so any mitigation occurs through an ex-post manual review. Some such cases from 2022 are still being evaluated by NYISO.
- *Fuel Oil Limitations*: Some dual fuel generators have insufficient fuel oil inventory to operate for long periods of time. In periods of sustained cold weather and gas market volatility like those witnessed in late December, such resources may either offer on natural gas costs or have extraordinary opportunity costs when operating on fuel oil. Although this does not constitute a competitive concern, it became more common during the winter months in 2022.

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, outside of a few isolated cases, 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.[239]
- 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

intervals over the past 90 days, adjusted for changes in day-ahead gas prices. This approach may under-state marginal costs for units that face fluctuating intraday fuel prices.

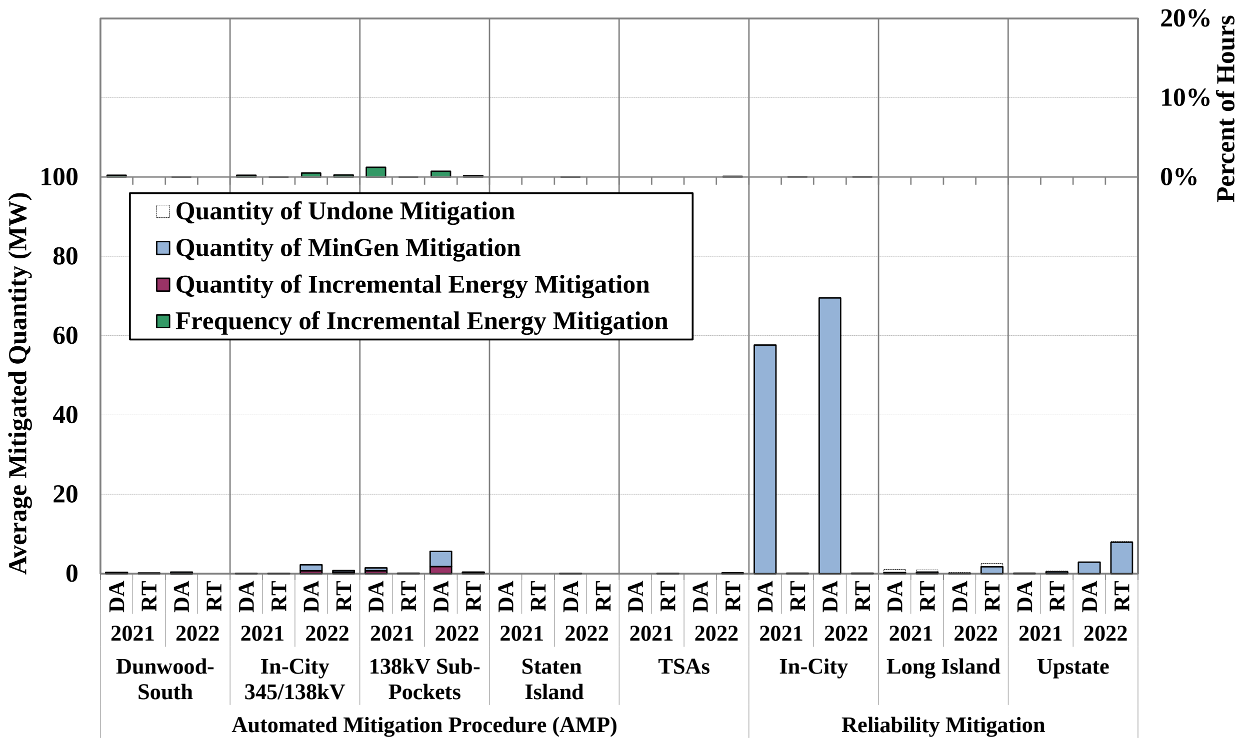
239 The conduct and impact thresholds used by AMP are determined by the formula provided in the NYISO Market Services Tariff, Section 23.3.1.2.2.1.

mitigated to its reference levels. A $0 conduct threshold is used in the day-ahead market and the AMP conduct threshold is used in the real-time market.

- Reliability Mitigation in Other Areas – When a generator is committed for reliability and the generator is pivotal, the start-up cost and minimum generation cost offers of the generator may be mitigated to its reference levels. A conduct threshold of the higher of $10 per MWh or 10 percent of the reference level is used.

Figure 38 summarizes the market power mitigation (i.e., offer capping) that was imposed in the day-ahead and real-time markets in 2021 and in 2022.

Figure 38: Summary of Day-Ahead and Real-Time Mitigation
2021 - 2022



This figure shows that most mitigation occurs in the day-ahead market when most supply is scheduled. Reliability mitigation accounted for 90 percent of all mitigation in 2022, 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 increased from 2021 to 2022 due to higher loads driving greater reliability commitments and higher emissions costs disproportionately impacting marginal costs of older, higher emitting generators.[240] The reliability mitigation is critical for ensuring that the market performs competitively because units that are needed for local reliability usually have market power.

240 See Section VI.F for more details on the reduced reliability commitments in New York City.

AMP mitigation accounted for just 10 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 2022 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 since the Indian Point units 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 committed. The NYISO recently recommended tariff changes to Attachment H to address the potential for firms to withhold by submitting biased fuel cost adjustments.[241] These tariff changes would address this potential problem by imposing financial sanctions on generators that submit biased FCAs to withhold capacity.

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.[242]

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

241 See presentation from March 7, 2023 MIWG.

242 See NYISO MST, Sections 23.4.5.2 to 23.4.5.6.

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 four evaluations.[243]

Parts 4 and 5 of this subsection discuss the application of capacity market mitigation measures in 2022.

4. Application of the Supply-Side Mitigation Measures

Given the sensitivity of prices in the Mitigated Capacity Zones, the supply-side market power mitigation measures are important for ensuring that capacity prices in these zones are set at competitive levels. 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.

5. Application of the Buyer-Side Mitigation Measures

The NYISO made major changes to the BSM rules in 2022 that effectively eliminate mitigation for state-sponsored policy resources.[244] Class Year 2021, which concluded in January 2023, included intermittent renewables, energy storage, and an HVDC transmission project with an award under the state's 'Tier 4' clean energy procurement in the mitigated capacity zones. All of the CY21 projects in the mitigated zones were considered to be Excluded Facilities and therefore not subject to BSM evaluation.

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

244 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. The tariff changes created a category of "Excluded Facilities" considered to contribute to New York state policy that are not subject to BSM evaluation, and eliminated the Renewable Entry Exemption, which was made redundant by this change.

XI. DEMAND RESPONSE PROGRAMS

Participation by demand response in the market is beneficial for many reasons. Demand response contributes to reliable system operations, long-term resource adequacy, lower production costs, decreased price volatility, and reduced supplier market power. Even modest reductions in consumption by end users during high-price periods can significantly reduce the costs of committing and dispatching generation to satisfy the needs of the system. These benefits underscore the value of designing wholesale markets that provide transparent economic signals and market processes that facilitate demand response. As more intermittent generation enters the market over the coming decades, demand response and price-responsive loads will become increasingly important as the NYISO maintains reliability, transmission security, and a supply-demand balance at the lowest cost.

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

- Meter Service Entity ("MSE") for DER – The MSE rules went into effect in May 2020, which authorize third party metering that provides greater flexibility to consumers and retail load serving entities for demand side participation.
- Dual Participation ("DP") – The DP rules went into effect in May 2020, which allow resources that provide wholesale market services to also provide retail market services.
- DER Participation Model – This is scheduled for implementation in the second quarter of 2023, 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 1,234 MW of demand response resources registered in New York are reliability demand response resources.[245]

[245] 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 1,234 MW of resources participating in 2022. 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 2022 primarily because of enhancements to auditing and baseline methodologies for SCRs since 2011 (registered quantity did not change significantly each year from 2013 to 2022).[246] 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 2022 Capability Period, SCRs made contributions to resource adequacy by satisfying:

- An average of 4.4 percent of the UCAP requirement for New York City;
- An average of 3.4 percent of the UCAP requirement for the G-J Locality;
- An average of 0.5 percent of the UCAP requirement for Long Island; and
- An average of 2.9 percent of the UCAP requirement for NYCA.

The SCR contributions to resource adequacy fell modestly since 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.[247]

Demand-Side Ancillary Services Program

This program allows demand-side resources to offer operating reserves and regulation service in the wholesale market. Currently, six 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 225 MW of operating reserves. However, the NYISO will retire this program when DSASP resources become eligible to utilize the Distributed Energy Resource ("DER") and Aggregation market rules.[248]

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[246] See Figure A-136 in the Section VIII.A of the Appendix for more details.

[247] See Section 4.1.1 of ICAP Manual for more details.

[248] 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. The NYISO will retire this program together with the DSASP once the DER Participation Model is implemented. Both DSASP and DADRP resources will be required to either transition to the DER Participation Model or withdraw from the market eventually. The NYISO will stop accepting DSASP and DADRP resource applications once the DER participation model is available.

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 2022, the NYISO activated SCR resources for the Capital Zone (~100 MW) on two days in July. The scarcity pricing rule was only triggered for a total of 21 five-minute intervals during the two events. 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 (and there is no reserve requirement specifically for the Capital Zone.

In addition, demand response resources in local utility programs were activated on 13 days in 2022. The amount of these deployments exceeded 200 MW on 10 days and ranged up to 750 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 or reduce NYCA capacity deficiency on four days.[249] Prices in the wholesale energy market did not indicate a need for peak load reduction on the other days.[250]

Utility demand response deployments are not currently considered in the market scheduling and pricing. The capacity of utility-activated demand response is not considered in day-ahead forecasts, which may lead to excessive reliability commitments or unnecessary out-of-market actions on high-load days, although this did not occur in 2022. 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.

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[249] See our analysis in Section V.I in the Appendix for more details.

[250] 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.

XII. Recommendations

Our analysis in this report indicates that the NYISO electricity markets performed well in 2022, although we recommend additional enhancements to improve market performance. Twenty-one 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 2021 SOM Report, but Recommendations #2022-1 to #2022-4 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

Number	Section	Recommendation	Current Effort
Energy Market Enhancements - Pricing and Performance Incentives			
2017-1	VI.F	Model local reserve requirements in New York City load pockets.	*Dynamic Reserves* project underway; complete market design targeted 2023.[251]
2015-16	VI.A	Dynamically adjust operating reserve requirements to account for factors that change the amount of reserves that must be held on internal resources.	
2017-2	VI.A	Modify operating reserve demand curves to improve shortage pricing and ensure NYISO reliability.	
Capacity Market – Design Enhancements			
2022-4	VIII.D, IV.A	Implement a dynamic process for defining granular locations in the capacity market.	
2021-4	VIII.F	Improve capacity modeling and accreditation for specific types of resources.	*Modeling Improvements for Capacity Accreditation* underway.

251 The 2022 Master Plan includes a 2025-2027 project called *More Granular Operating Reserves* to address Recommendation 2017-1 following the implementation of the *Dynamic Reserves* project in 2026.

Other Recommendations

Number	Section	Recommendation	Current Effort
Energy Market Enhancements - Pricing and Performance Incentives			
2021-1	VI.F	Evaluate need for longer lead time reserve products to address increasing operational uncertainties.	*Balancing Intermittency* will investigate.
2021-2	VI.F, VI.G	Model full reserve requirements for Long Island.	
2021-3	VI.F, VII.B	Consider modeling transient voltage recovery constraints on Long Island in the energy market.	
2019-1	VI.F, XI	Set day-ahead and real-time reserve clearing prices considering reserve constraints for Long Island.	Facilitated by *Dynamic Reserves* project.[252]
2016-1	VI.D	Consider rules for efficient pricing and settlement when operating reserve suppliers provide congestion relief.	
2015-9	IX.C	Eliminate transaction fees for CTS transactions at the PJM-NYISO border.	
2015-17	VI.A	Utilize constraint-specific graduated transmission demand curves to set constraint shadow prices during transmission shortages.	*Constraint-Specific Transmission Shortage Pricing* implementation in 2023.
Energy Market Enhancements – Real-Time Market Operations			
2020-1	VI.C	Consider enhancements to the scheduling of duct-firing capacity in the real-time market that more appropriately reflects its operational characteristics.	[253]
2020-2	VI.A	Eliminate offline fast-start pricing from the real-time dispatch model.	[254]
2012-8	VI.E	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	IXIX.C	Adjust look ahead evaluations of RTD and RTC to be more consistent with the timing of external transaction ramp and gas turbine commitment.	

252 The 2022 Master Plan includes a 2024-2026 project called *Long Island Reserve Pricing* to address this along with the implementation of the *Dynamic Reserves* project in 2026.

253 The 2022 Master Plan includes a 2024-2025 project called *Improve Duct Firing Modeling* that would partially address this recommendation.

254 The 2022 Master Plan includes a 2024 project called *Eliminate Offline GT Pricing* that would address this recommendation.

Number	Section	Recommendation	Current Effort
Capacity Market – Design Enhancements			
2022-1	VIII.G	Compensate capacity suppliers based on their contribution to transmission security when locational capacity requirements are set by transmission security needs.	[255]
2022-2	VIII.I	Establish seasonal capacity requirements and demand curves.	*ICAP Demand Curve Reference Point Proposal* as part of Demand Curve Reset[256]
2013-1c	VIII.E, IV.A	Evaluate locational marginal pricing of capacity ("C-LMP") that minimizes the cost of satisfying planning requirements.	
2012-1c	VIII.H, IV.A	Grant financial capacity transfer rights between zones for market-based transmission upgrades that help satisfy planning reliability needs.	
Planning Process Enhancements			
2022-3	IV.B	Improve transmission planning assumptions and metrics to better identify and fund economically efficient transmission projects.	

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 2023 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.

255 The 2022 Master Plan includes a 2024-2027 project to consider related issues called *Valuing Transmission Security*.

256 The 2022 Master Plan includes a 2025-2027 project to consider this called *Winter Reliability Capacity Enhancements*.

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.[257] 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. While the existing reserve products are designed to satisfy contingency reserve needs (i.e., being prepared for the occurrence of specific unforeseen events), longer lead time reserves

[257] 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.

are needed for dispatch in case load or intermittent generation deviate significantly from the forecasted level. Thus, longer lead time reserves would be scheduled and deployed differently from the existing contingency reserve products. Longer lead time reserve 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.

NYISO considered potential future operational issues that may be faced by the grid in its 2022 *Grid in Transition* study. NYISO plans to consider related market design changes – including an evaluation of the need for a longer-term reserve product and/or longer sustainability requirement for reserve providers – as part of its 2023 *Balancing Intermittency* project.[258]

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 have relied on out-of-market commitments during some conditions (e.g., the summer of 2021).[259] Moreover, increasing penetration of intermittent renewable generation will increase the need for out-of-market commitments. 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.[260] 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

258 "Balancing Intermittency: Project Kickoff", NYISO presentation to ICAP Working Group, February 21, 2023, available here.

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

260 See discussion in Section VII.B.

using surrogate constraints, so that generation scheduled to satisfy TVR criteria for the East End 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. 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: NYISO's 2022 Master Plan indicates that it intends to address this recommendation through the planned *Long Island Reserve Pricing* project in 2026, following implementation of the *Dynamic Reserves* market design in 2023 which will include the capability to dynamically procure reserves on Long Island.

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

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.[262] New

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261 See discussion in Section VI.F.F

262 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.

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: NYISO plans to address this recommendation after the implementation of the *Dynamic Reserves* project, which will provide the needed functionality to implement New York City load pocket reserves.[263] 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 solely based on the loss of two Bulk System transmission elements.

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 does 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. 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.

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 $4,000 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.[264] 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.

263 See December 6, 2022 ICAPWG presentation "Dynamic Reserves" at p. 30 (available here).

264 See discussion in Section VI.A.

Status: NYISO intends to consider whether current reserve shortage pricing levels are appropriate in its 2023 *Balancing Intermittency* project, but its analysis will focus on generator input costs and not the value of the reserve product itself.[265]

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;
- The real-time market schedules available resources so that NYISO operators do not need to engage in out-of-market actions to maintain reliability, and
- NYISO real-time scheduling models prioritize appropriately when multiple reserve requirements and/or transmission constraints are simultaneously in shortage.

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.

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.[266]

265 "Balancing Intermittency: Project Kickoff", NYISO presentation to ICAP Working Group, February 21, 2023, available here.

266 We describe a conceptual approach to providing efficient compensation by setting reserve clearing prices at the nodal level in this report. See discussion in Section VI.D and Appendix V.M.

New York City is expected to lose most of its peaking generation over the next three years and it is 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. This recommendation was previously High Priority, but this designation was removed given the complexity and projected level of near-term benefits compared with other important market design efforts.

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 $2.4 million in 2022 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.[267]

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

267 See Section IX.C. See 2023 Project Candidate: *Eliminate Fees for CTS Transactions with PJM*.

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.[268]

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 lead-time 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. In 2022, NYISO developed a market design concept building on this work.[269] NYISO currently targets a phased approach with development of complete market design elements in 2023-2024 and deployment in 2025-2026.

We identify six examples where dynamic reserve functionality would provide significant benefits below and comment on the treatment of each of them in the 2022 Market Design Concept Proposal:

- *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 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.
    - ✓ NYISO's 2022 Market Design Concept Proposal would include dynamic reserve scheduling on Long Island.

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268 See discussion in Section VI.A. See Section V.L of the Appendix for a potential mathematical modeling approach. See 2023 Market Project *Dynamic Reserves*.

269 See December 6, 2022 ICAPWG presentation "Dynamic Reserves" (available here).

- *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 2022 Market Design Concept Proposal 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 2022 Market Design Concept Proposal 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 2022 Market Design Concept Proposal would partially address this by increasing the NYCA 30-minute reserve requirement by the difference between forecast load and bid load. NYISO intends to continue to assess this issue in the Dynamic Reserves project in 2023.
- *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 intends to pursue modeling NYC load pockets following completion of the *Dynamic Reserves* project, which would create functionality to do so.
- *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 and the 2022 Market Design Concept Proposal did not address this. We recommend NYISO

incorporate this feature into its Market Design Concept proposal in the 2023 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.[270] These enhancements were approved by stakeholder vote at NYISO's Management Committee in October 2021. In 2022, NYISO developed functional requirements to implement these changes and advances a proposal for the application of transmission shortage pricing when multiple transmission constraints (such as lines in series or contingency combinations) are active.[271] We anticipate that NYISO's proposal will be implemented in 2023 and will address this recommendation.

Energy Market Enhancements – Real-Time Market Operations

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

Generators with duct firing capacity are able to offer it into NYISO's real-time market as a portion of the dispatchable range of the generator. However, duct-firing capacity is generally not capable of following a 5-minute dispatch signal. The process of starting-up and shutting-down duct burners is similar to the start-up and shut-down of a fast start peaking unit. For this reason, many generators with duct-firing capability do not offer it into the real-time market, while others "self-schedule" this capacity inflexibly. There is approximately 900 MW of duct-firing capacity

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

271 See NYISO MIWG/ICAPWG presentation to Business Issues Committee on June 2022, 2022: "Constraint Specific Transmission Shortage Pricing: Pricing Proposal for Multiple Active Constraints", available here.

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.[272] 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: NYISO developed a conceptual proposal to address this recommendation in its *Improve Duct Firing Modeling* project in 2022.[273] NYISO's 2022 Master Plan indicates that it intends to complete market design work to address this recommendation in 2024 and implement its design in 2025.

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

Status: NYISO's 2022 Master Plan proposes to develop market rule enhancements to address this recommendation for deployment in 2024.

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

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272 See discussion in Section VI.C.

273 See NYISO MIWG/ICAPWG presentation on September 30, 2022 "Improve Duct-Firing Modeling – Update", available here. NYISO's preliminary design would work by allowing generators to designate some operating ranges as available for energy at a reduced response rate but unable to provide regulation and 10-minute reserves. This design is promising, but generators would identify the duct-firing range using a registration parameter rather than a biddable parameter. Since the duct-firing range moves like the upper operating limit based on ambient temperature and humidity conditions, it is unclear whether the design would provide significant benefits.

274 See discussion in Section VI.A and 2023 Project Candidate *Eliminate Offline GT Pricing*. This project was not prioritized for 2023 but is included in NYISO's 2022 Master Plan with deployment targeted for 2024.

transmission tariffs and the NYISO's markets. In 2022, 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) 96 percent of the time. We estimate that their operation increased production costs by $22 million]. Furthermore, we estimate that their operation increased New York State emissions of carbon dioxide by 1.3 percent (455 thousand tons) and nitrous oxide by 8 percent (607 tons).[275]

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

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 in the ramp assumptions for units that are in the process of shutting-down and changes in external transactions schedules between RTC and RTD are a principal driver the price volatility evaluated above. 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:[276]

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

275 See discussion in Section VI.E. See 2023 Project Candidate: *Long Island PAR Optimization & Financial Rights*.

276 See discussion in Sections IX.C. See 2023 Project Candidate: *Review of Real-Time Market Structure*.

regulation (since regulation deployments may lead the unit to move against its five-minute dispatch instruction).

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

Capacity Market – Design Enhancements

2022-1: Compensate capacity suppliers based on their contribution to transmission security when locational capacity requirements are set by transmission security needs.

NYISO determines Locational Capacity Requirements (LCRs) annually using the "LCR Optimizer" method, but the LCRs are subject to a minimum floor in each locality that is designed to respect transmission security criteria. NYISO has recently taken steps to align its calculation of Transmission Security Limits (TSLs) that are used in the LCR process with the methodology used in its reliability planning studies. This has resulted in LCRs being set at the TSL-based floor in multiple localities, and the importance of the TSLs is expected to grow.

Some resources, including large-contingency resources and Special Case Resources (SCRs), are assumed to provide limited value for meeting transmission security planning requirements. SCRs are not counted as helping satisfy transmission security requirements, while large supply resources constituting one of the two largest in a given area tend to increase the capacity requirement in the area. For example, in New York City, supply resources exceeding 700 MW generally increase the capacity requirement in the city. Consequently, the presence of these resources causes LCRs to increase when set by the TSL methodology. This causes consumer costs to increase and undermines efficient incentives for investment, because some suppliers receive payment based on requirements which they do not help to resolve. To address this, we recommend paying resources the highest capacity price among requirements which they contribute to meeting.[277] For large-contingency units, this recommendation should not apply to the portion of the unit that does not cause an increase in the Transmission Security Limit.

2022-2: Establish seasonal capacity requirements and demand curves. (Current Effort)

NYISO's capacity market uses the same installed capacity requirements in all months of the year. The level of surplus supply in each spot capacity auction is determined by the amount of

277 See discussion in Section VIII.G. This will require the NYISO to determine what the LCR would be if there was no TSL requirement so that it can determine a resource's contribution to satisfying resource adequacy needs.

installed capacity relative to this annual requirement. This usually bears little relationship to actual seasonal reliability risk, which is determined by seasonally available supply (considering resource deratings) and seasonal load levels. As a result, seasonal prices are determined by the level of installed capacity (regardless of its actual availability) and may fail to provide incentives that correspond to seasonal reliability risk. Furthermore, the process for setting annual requirements may be poorly-suited to the timeframe required for winter fuel procurement decisions. Hence, we recommend considering implementation of separate seasonal capacity requirements and demand curves that would reflect the level of supply needed to maintain reliability in each season.

In early 2023, NYISO proposed changes to its capacity market demand curves that would establish separate seasonal values for the reference point (i.e., the price when supply is equal to the requirement) considering the expected proportion of reliability risk in each season. This proposal is an improvement which will better align prices with expected reliability risk when the system is at its tariff-prescribed level of excess. However, because the level of surplus in each auction will still be determined based on installed capacity compared to a single annual requirement, prices will fail to send efficient incentives to maintain reliability in many circumstances. Hence, we recommend moving to a market with separate seasonal requirements.[278]

Status: As part of the 2024 Demand Curve Reset, NYISO is designing a process that would implement seasonal capacity demand curves in the summer in the winter reflecting the relative reliability risks in each season.[279] However, this will not address the need for distinct summer and winter capacity requirements and other parameters that should differ between seasons.

2022-4: Implement a dynamic process for defining granular locations in the capacity market. (High Priority)

NYISO's capacity market has four pricing zones in which all suppliers are paid the same capacity price. However, the marginal value of capacity differs by location due to internal transmission constraints within each of the current capacity zones. For example, bottlenecks limit the deliverability of capacity in Staten Island to the rest of New York City, but Staten Island suppliers are paid the premium New York City price. This results in inflated consumer payments and reduces incentives to retain capacity in areas where there are reliability needs or to retire capacity in areas with oversupply. NYISO's current tariff-defined zone creation process is not capable of creating new capacity zones in a timely manner.

278 See discussion in Section VIII.I

279 See section on "ICAP Demand Curve Reference Point Price Proposal" in February 21, 2023 NYISO ICAPWG presentation "2025 - 2029 ICAP Demand Curve Reset", available here.

Hence, we recommend implementing and dynamically updating an expanded set of capacity zones that will reflect the known bulk transmission bottlenecks on the NYISO system.[280] This process would establish requirements for all load zones and designated sub-zone areas using the LCR Optimizer method. It would price capacity using demand curves for regions with binding transmission constraints in NYISO's resource adequacy model GE-MARS. As part of this process, it will be necessary to define export demand curves for regions that have surplus capacity and face transmission bottlenecks.

This recommendation is high priority because (1) significant overpayment by consumers is already occurring due to overpricing of export-constrained areas, and (2) coming changes in reliability needs (such as a the growing importance of winter reliability) make it critical for the capacity market to be able to accurately signal the value of retaining and attracting capacity where it is needed.

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

FERC approved tariff revisions in 2022 that will 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;
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 and humidity 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.

280 See discussion in Section VIII.D and Section IV.A.

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.[281] In the longer-term, it will also become necessary to also model fuel inventory limitations because MARS does not evaluate the potential for oil-fired and dual-fuel units with limited on-site fuel to deplete their inventories during winter cold snaps.

NYISO is currently pursuing the *Modeling Improvements for Capacity* Accreditation project, which aims to develop changes to MARS needed for accurate capacity accreditation directly. NYISO and the New York State Reliability Council (NYSRC) have recently developed plans to address the issues listed above (among others) between 2022 and 2026.[282] We support NYISO and NYSRC's efforts to place a high priority on incorporating these changes in IRM studies.

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

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

We recommend the NYISO evaluate 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.[283] 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.

281 See discussion in Section VIII.F. Also see discussion of functionally unavailable capacity on high load days in our Q3 2022 Quarterly Report on the NYISO markets (pages 22-23 and 90), available here.

282 See summary of NYSRC priorities in NYISO October 19, 2022 ICAPWG presentation "Capacity Accreditation" and January 26, 2023 presentation "Modeling Improvements for Capacity Accreditation: Project Kick Off".

283 See discussion in Section VIII.E and Section IV.A See 2023 Project Candidate: *Locational Marginal Pricing of Capacity*.

This recommendation 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.[284]

Enhance Planning Processes

2022-3: Improve transmission planning assumptions and metrics to better identify and fund economically efficient transmission projects.

In recent years, NYISO transmission planning has been driven solely by the need to integrate expected future renewable resources under the Public Policy Transmission Process (PPTP). NYISO has recently updated its Economic Planning Process with a focus on long-term informational forecasting of the resource mix and congestion patterns (the Outlook) that forms the basis for eventual evaluation of projects in the PPTP.[285] Flaws in the methodology used for evaluating benefits may cause NYISO-led solicitations for public policy transmission to select a project that fails to efficiently address the underlying need or that is not the best among competing projects. In this report, we recommend the following enhancements that will lead more cost effective projects to be selected in future solicitations:[286]

d) Update the methodology of the Outlook study to better account for market incentives of renewable and storage resources;

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284 See discussion in Section VIII.H and IV.A. See 2023 Project Candidate: *Capacity Transfer Rights for Internal Transmission Upgrades*.

285 For a summary of the current economic planning process and 2021-2040 Outlook results, see October 25, 2022 NYISO public presentation "Economic Planning Process – 2021-2040 System & Resource Outlook", available here. See also NYISO MMU review of the 2021-2040 Outlook, available here.

286 See discussion in Section IV.B.

e) Evaluate economic and PPTN projects using a project case that considers changes to the resource mix resulting from the Project's inclusion; and
f) Estimate transmission project benefits based on their NYISO market value.

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 2021 SOM Report

The NYISO has moved forward with market reforms in response to the following recommendations from the 2021 State of the Market Report:

2019-4: Modify translation of the annual revenue requirement for the demand curve unit into monthly demand curves that consider reliability value – The NYISO proposed tariff changes in early 2023 that would set the ICAP demand curve reference points in summer and winter in a manner that considers the expected seasonal ratio of reliability risk in the IRM study. The proposed changes are intended to take effect in the 2025/26 capability year, concurrent with the updated ICAP Demand Curve parameters resulting from the upcoming 2024 Demand Curve Reset study. While NYISO's proposal represents an improvement in setting prices based on seasonal reliability risk, we believe it will be necessary to establish seasonal capacity requirements in order to efficiently compensate seasonal capacity suppliers. Hence, this recommendation is superseded by Recommendation 2022-2.

Other Recommendations Not Included on the List for 2022

2015-7: Reform the transmission planning process to better identify and fund economic transmission investments – NYISO recently implemented updated to its Economic Planning Process, resulting in completion of the initial System & Resource Outlook study in 2022. Although bulk transmission planning is an area of active interest in New York, NYISO's Economic Planning Process primarily serves an informational role and the evaluation of proposed projects is primarily conducted through the Public Policy Transmission Process. Hence, this recommendation is superseded by Recommendation 2022-3, which recommends improvements to the Outlook study and evaluation techniques used in other processes.

Analytic Appendix

2022 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 2022 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.

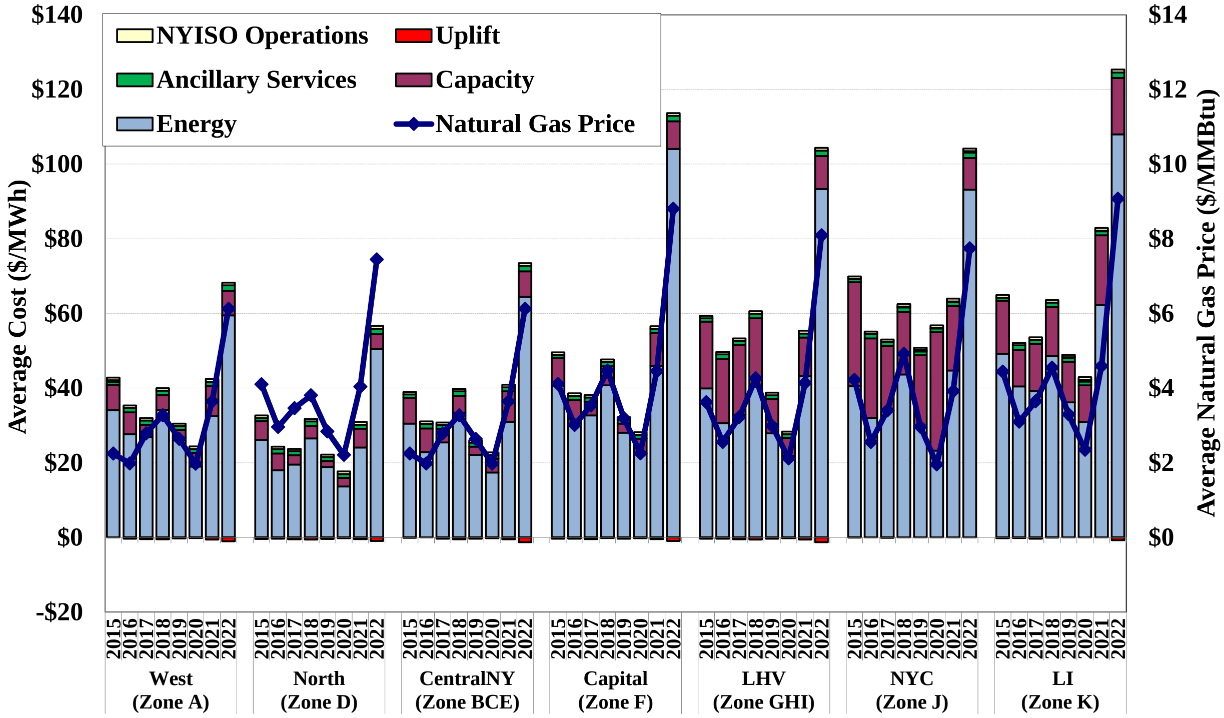
A. Wholesale Market Prices

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 2015 to 2022 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
2015 – 2022



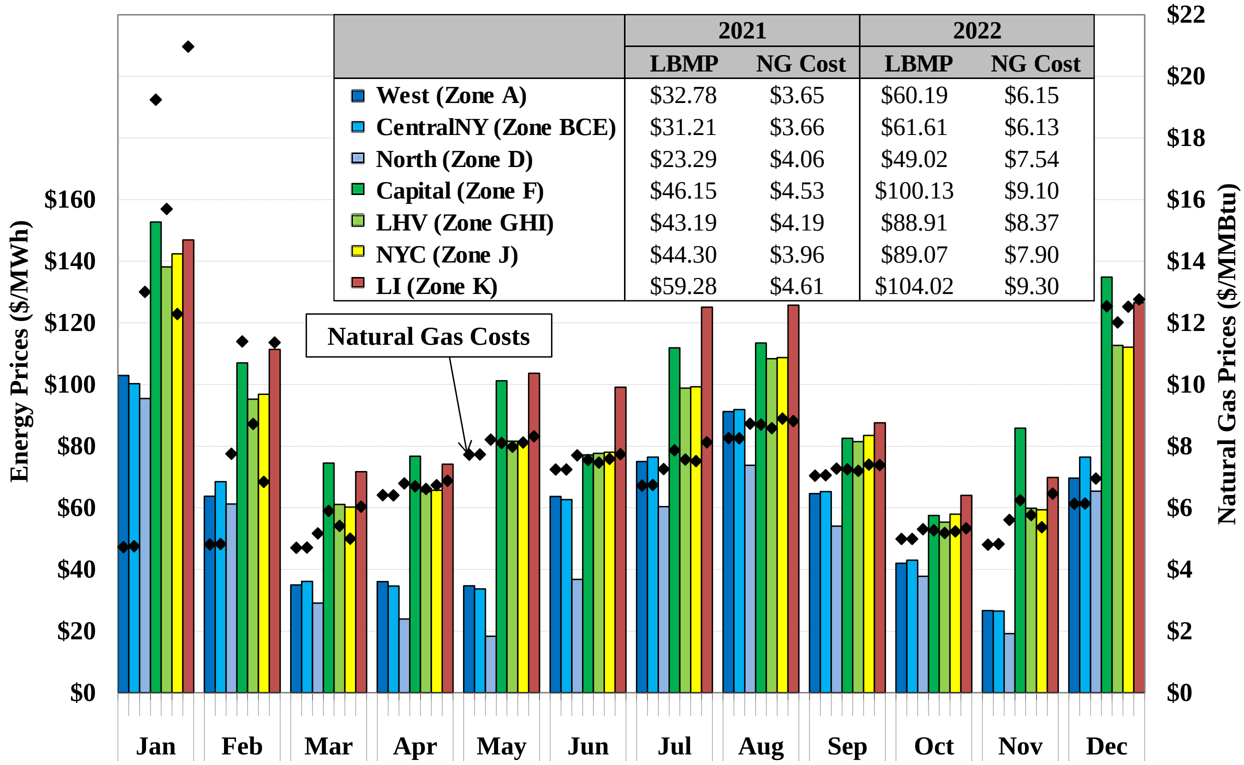
Natural gas prices are based on the following gas indices (plus a transportation charge): (a) the Niagara index during the months December through March and Tennessee Zone 4 200L index during the rest of the year for the West Zone and for Central New York; (b) the Iroquois Waddington index for North 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.[287] 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.

287 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 2022 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 2021 and 2022. 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.[288]

Figure A-2: Day-Ahead Electricity Prices and Natural Gas Costs
By Month, 2022



	2021		2022	
	LBMP	NG Cost	LBMP	NG Cost
West (Zone A)	$32.78	$3.65	$60.19	$6.15
CentralNY (Zone BCE)	$31.21	$3.66	$61.61	$6.13
North (Zone D)	$23.29	$4.06	$49.02	$7.54
Capital (Zone F)	$46.15	$4.53	$100.13	$9.10
LHV (Zone GHI)	$43.19	$4.19	$88.91	$8.37
NYC (Zone J)	$44.30	$3.96	$89.07	$7.90
LI (Zone K)	$59.28	$4.61	$104.02	$9.30

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).[289] Thus, if

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288 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.

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

the electricity price is $90 per MWh, the VOM cost is $3 per MWh, the natural gas price is $8 per MMBtu, and the RGGI clearing price is $13 per CO_2 allowance, this would imply that a generator with a 9.9 MMBtu per MWh heat rate is on the margin.[290]

Figure A-3 shows the load-weighted average implied marginal heat rate in each month of 2022 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 2021 and in 2022 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, 2022

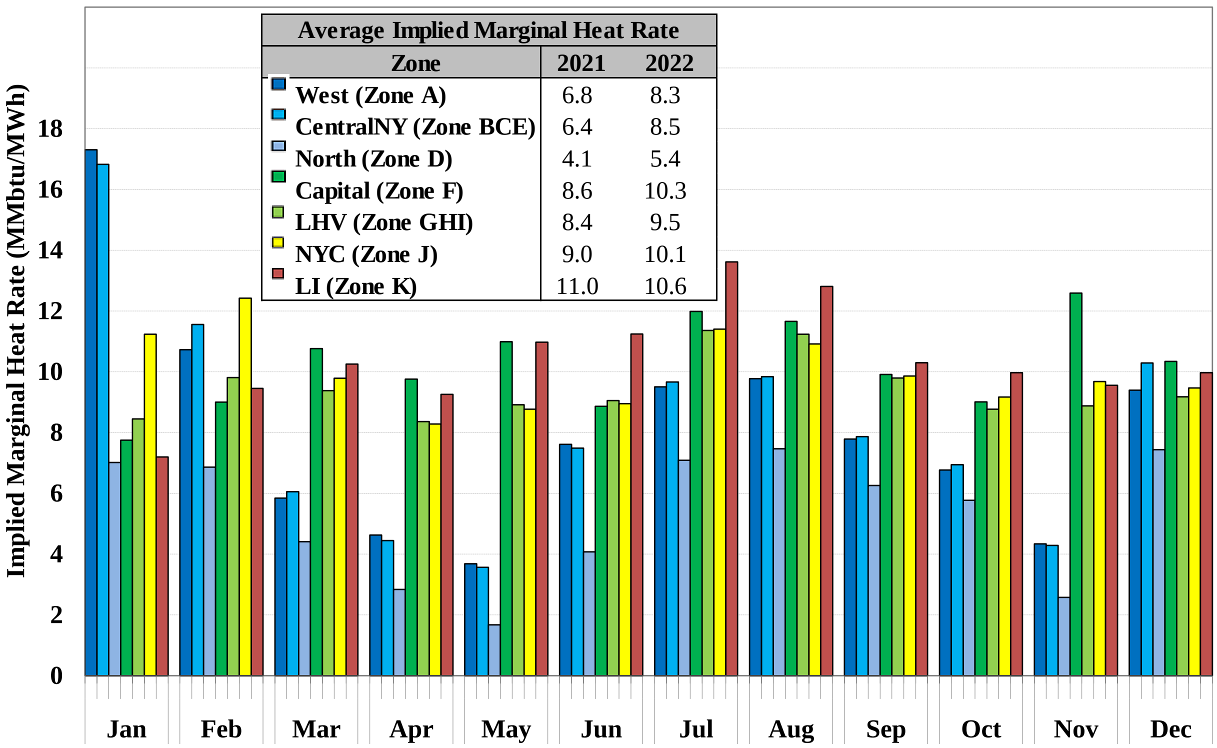


Figure A-4 – Figure A-5: Price Duration Curves and Implied Heat Rate Duration Curves

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

290 In this example, the implied marginal heat rate is calculated as ($90/MWh – $3/MWh) / ($8/MMBtu + $13/ton * 0.06 ton/MMBtu emission rate), which equals 9.9 MMBtu per MWh.

on the vertical axis. The table in the chart shows the number of hours in 2022 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.[291] 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

2022

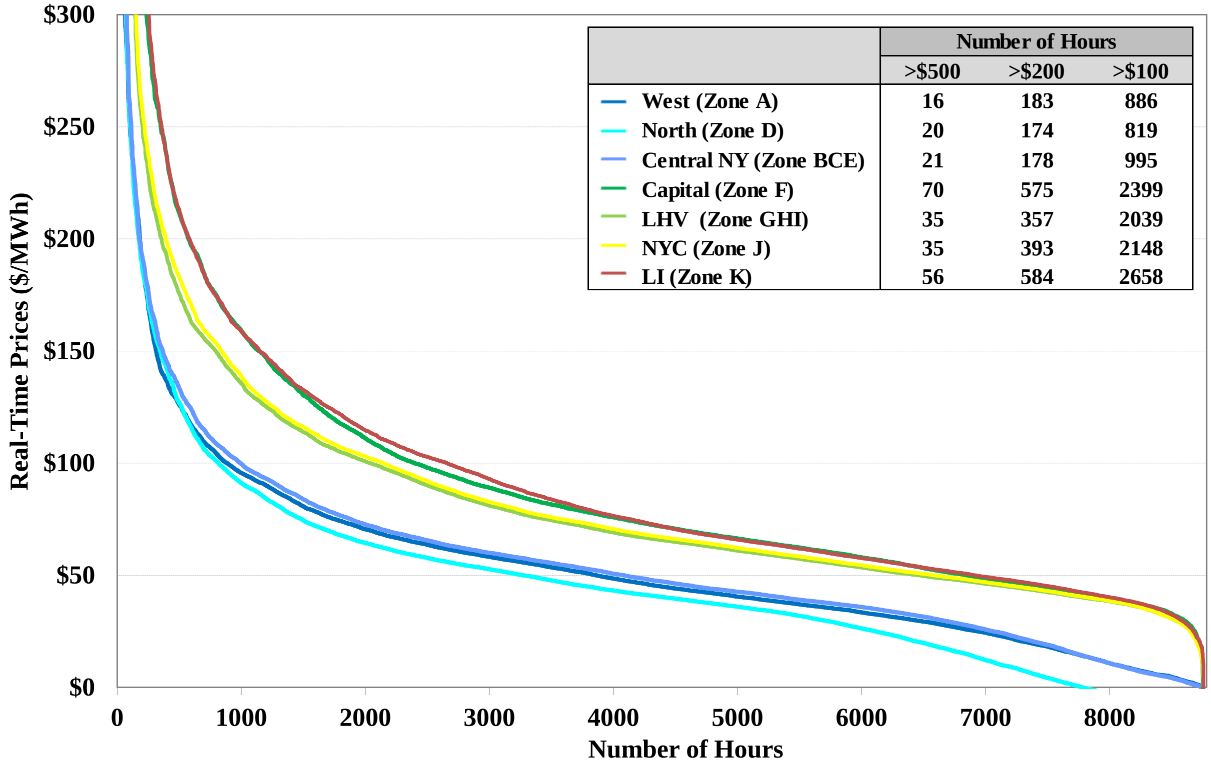
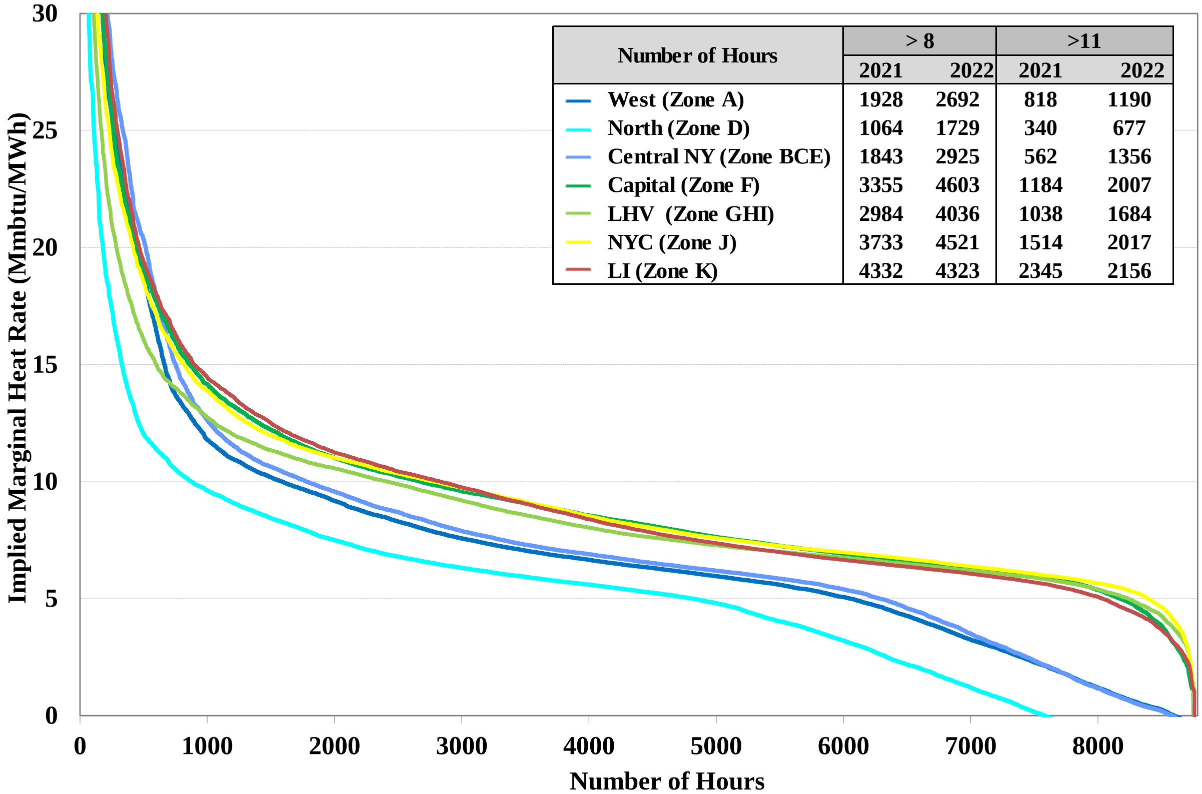


Figure A-5 shows the implied marginal heat rate duration curves at each location from the previous chart during 2022. Each curve shows the number of hours on the horizontal axis when the implied marginal heat rate for each sub-region was greater than the level shown on the vertical axis. The calculation 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 2021 and 2022.

291 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
2022



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.[292] 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.[293] Since most large steam units can

292 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.

293 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.[294]

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 2019 to 2022. The table compares the annual average fuel prices for these four years. [295]

Figure A-7 shows the quantities of generation by fuel type in seven regions of New York in each quarter of 2022 as well as for NYCA as a whole.[296] The table in the chart shows annual average generation by fuel type from 2020 to 2022.

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 2022. 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.

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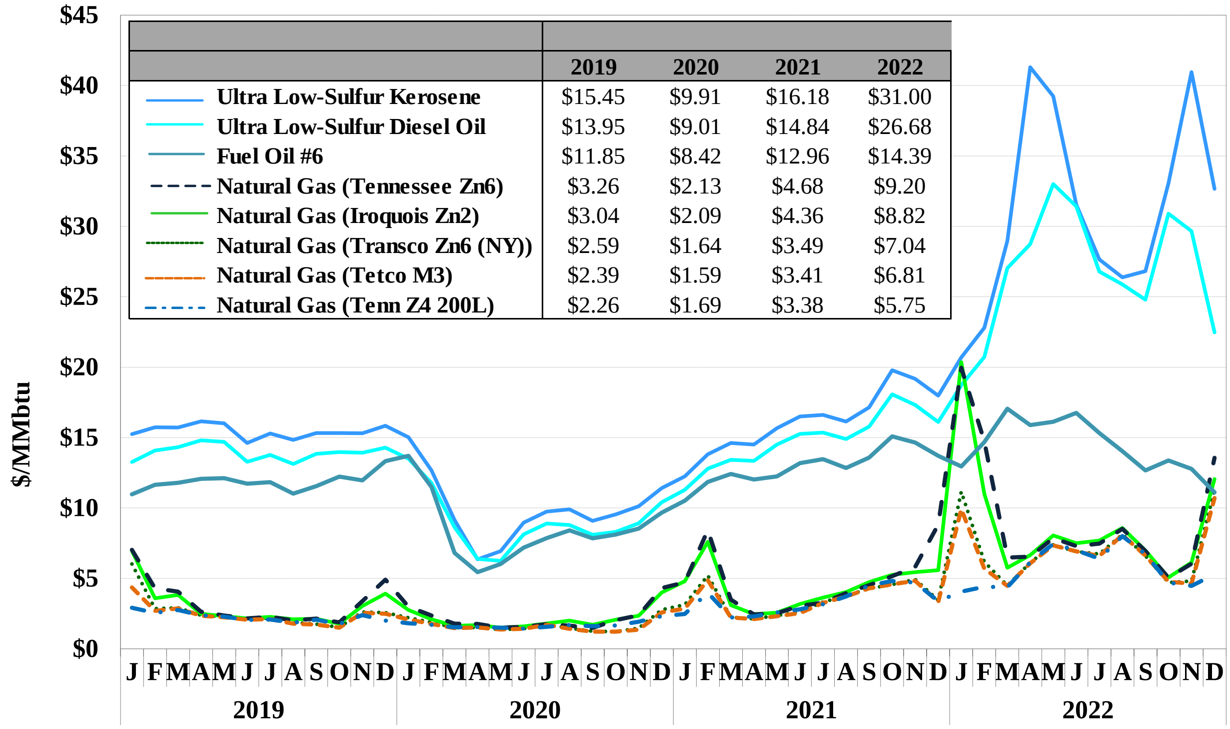
294 Emissions restrictions have tightened over the past years such that some steam turbines in New York City burn a No. 4 residual fuel oil blend.

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

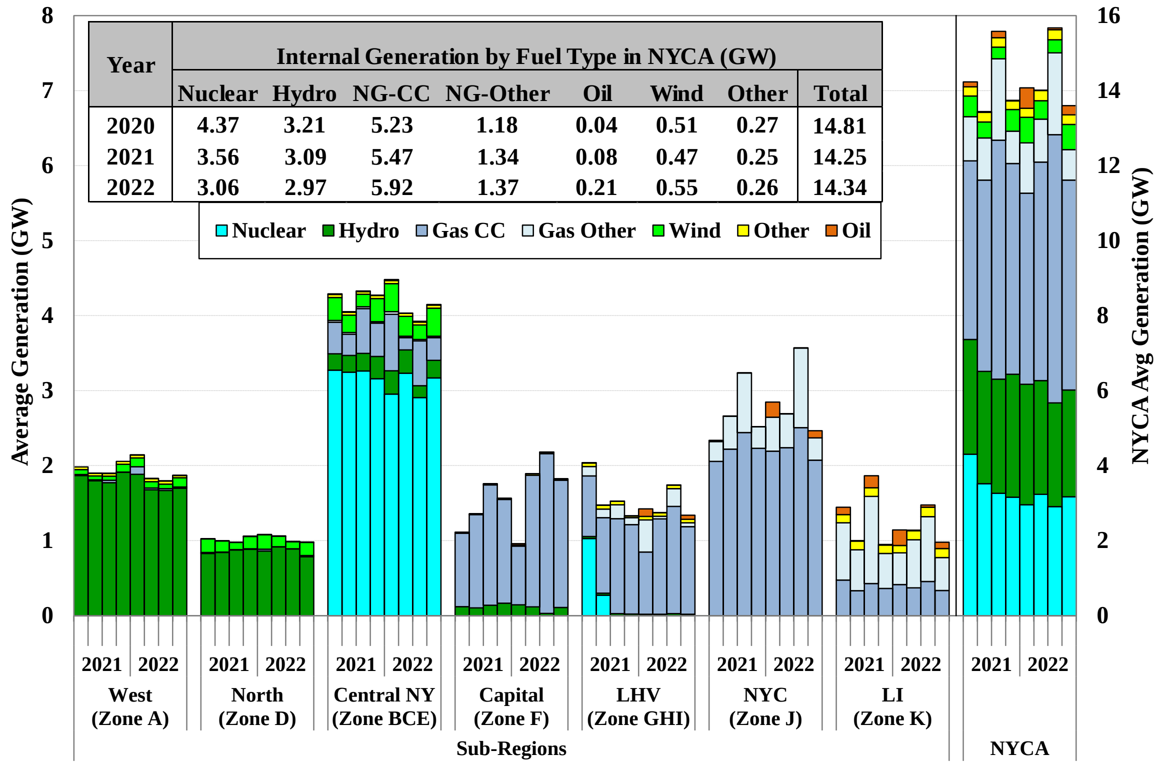
296 Pumped-storage resources in pumping mode are treated as negative generation. The “Other” category includes methane, refuse, solar, and wood.

Figure A-6: Monthly Average Fuel Index Prices
2019 – 2022



	2019	2020	2021	2022
Ultra Low-Sulfur Kerosene	$15.45	$9.91	$16.18	$31.00
Ultra Low-Sulfur Diesel Oil	$13.95	$9.01	$14.84	$26.68
Fuel Oil #6	$11.85	$8.42	$12.96	$14.39
Natural Gas (Tennessee Zn6)	$3.26	$2.13	$4.68	$9.20
Natural Gas (Iroquois Zn2)	$3.04	$2.09	$4.36	$8.82
Natural Gas (Transco Zn6 (NY))	$2.59	$1.64	$3.49	$7.04
Natural Gas (Tetco M3)	$2.39	$1.59	$3.41	$6.81
Natural Gas (Tenn Z4 200L)	$2.26	$1.69	$3.38	$5.75

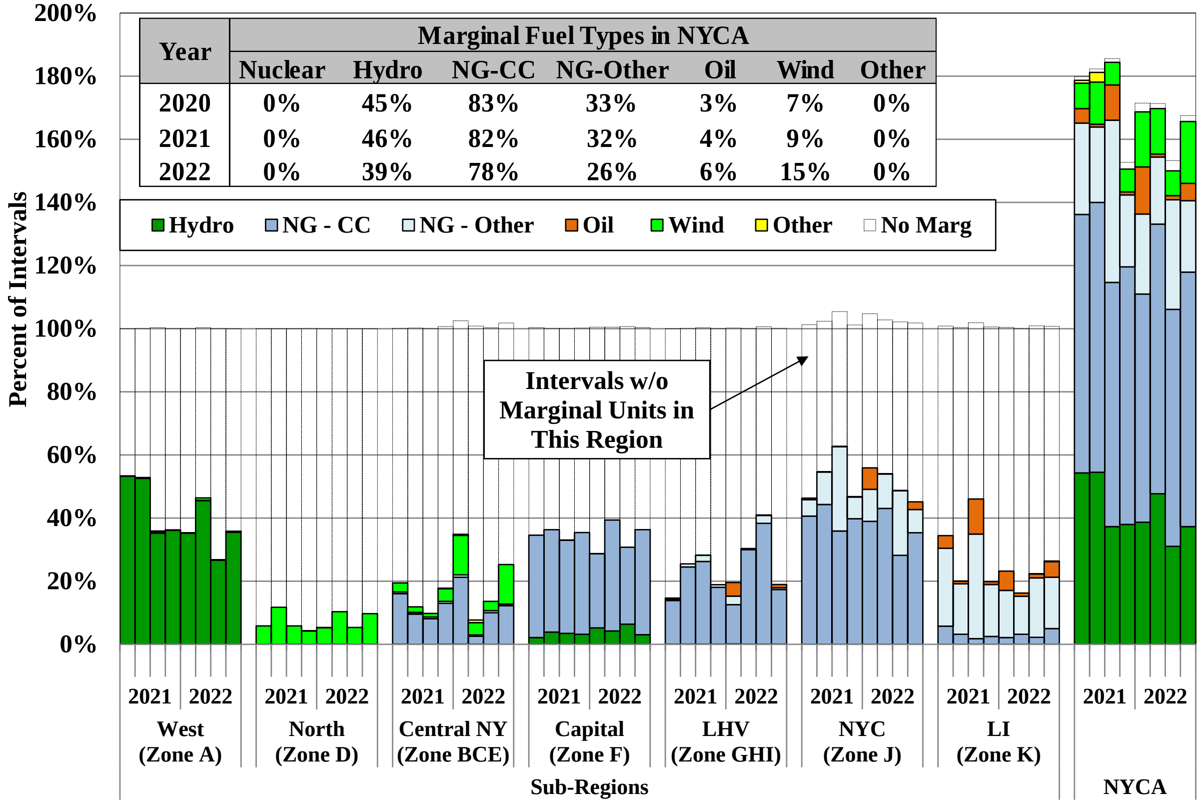
Figure A-7: Generation by Fuel Type in New York
By Quarter by Region, 2022



Year	Internal Generation by Fuel Type in NYCA (GW)							
	Nuclear	Hydro	NG-CC	NG-Other	Oil	Wind	Other	Total
2020	4.37	3.21	5.23	1.18	0.04	0.51	0.27	14.81
2021	3.56	3.09	5.47	1.34	0.08	0.47	0.25	14.25
2022	3.06	2.97	5.92	1.37	0.21	0.55	0.26	14.34

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, 2022



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.

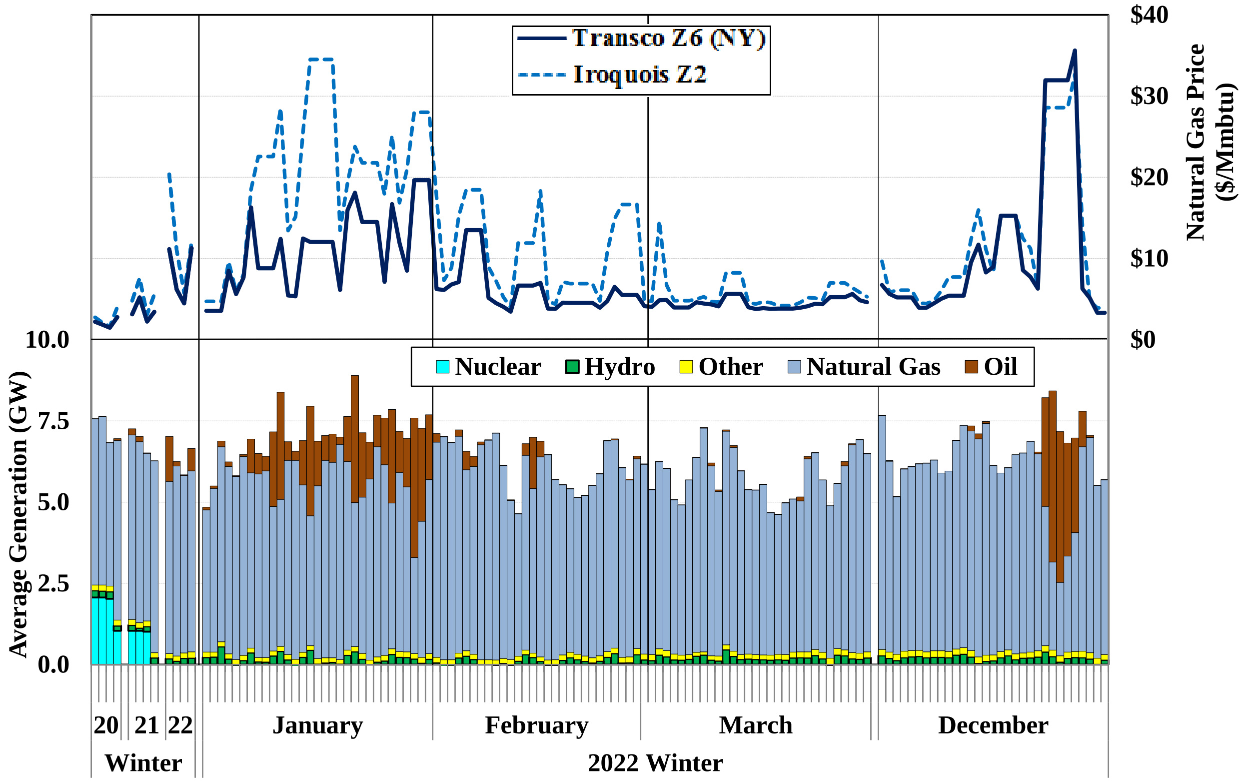
This subsection examines actual fuel usage in the winter of 2022, focusing on the portion of the year where the supply of natural gas is likely to be tight. This has historically had a big impact on the system operations, especially in Eastern New York.

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 2022 (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 2020 and 2022. 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, 2022



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 generation 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, 2000-2022

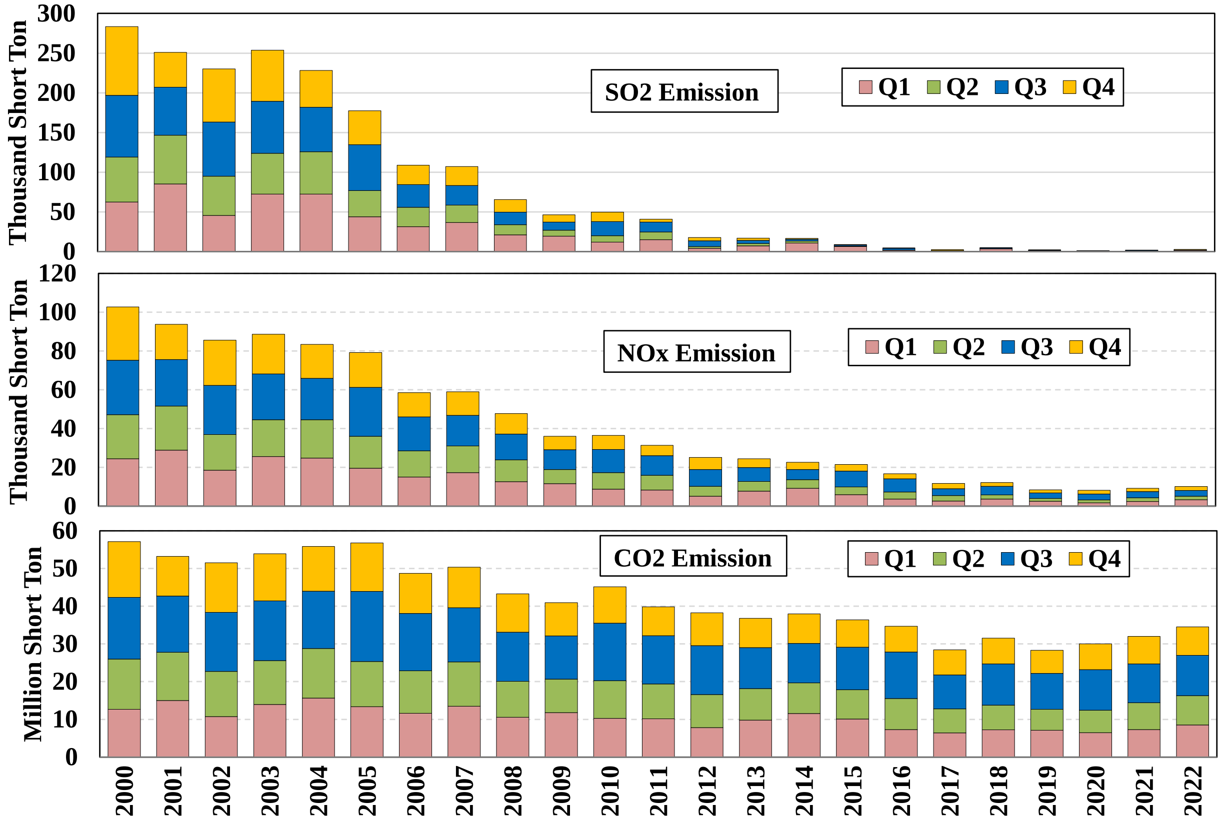


Figure A-11 - Figure A-13: Emissions by Region by Fuel Type

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 2021 and 2022. 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, 2021-2022

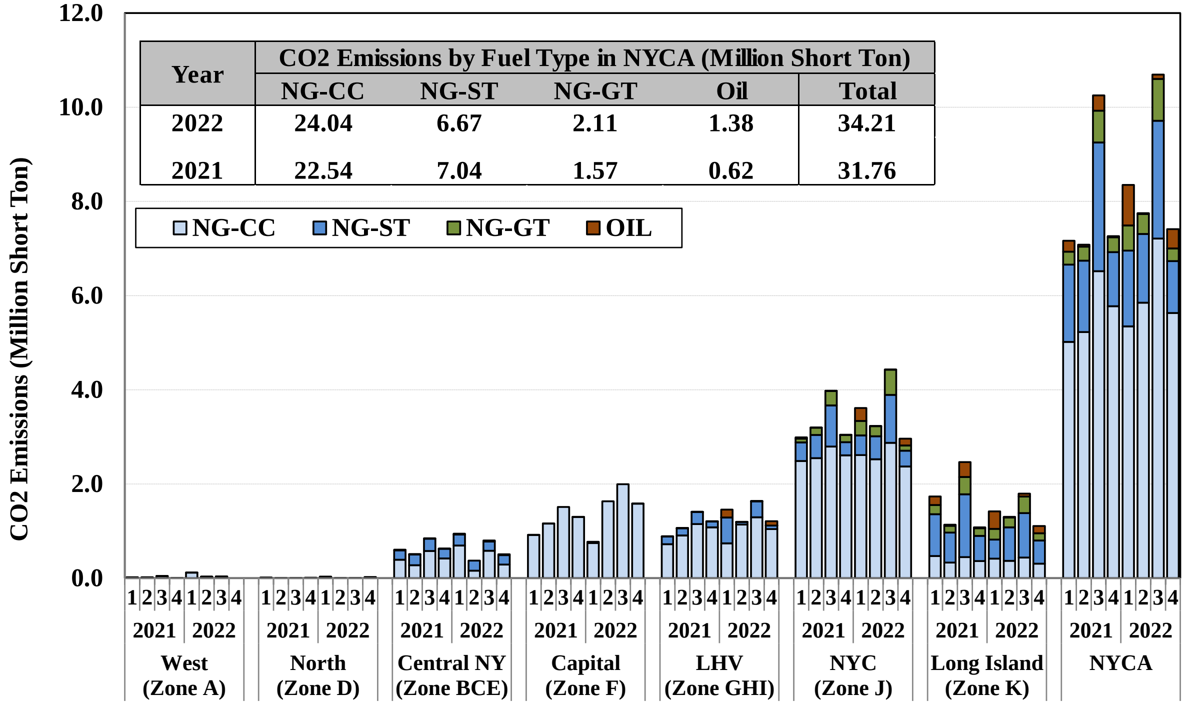


Figure A-12: NOx Emissions by Region by Fuel Type
by quarter, 2021-2022

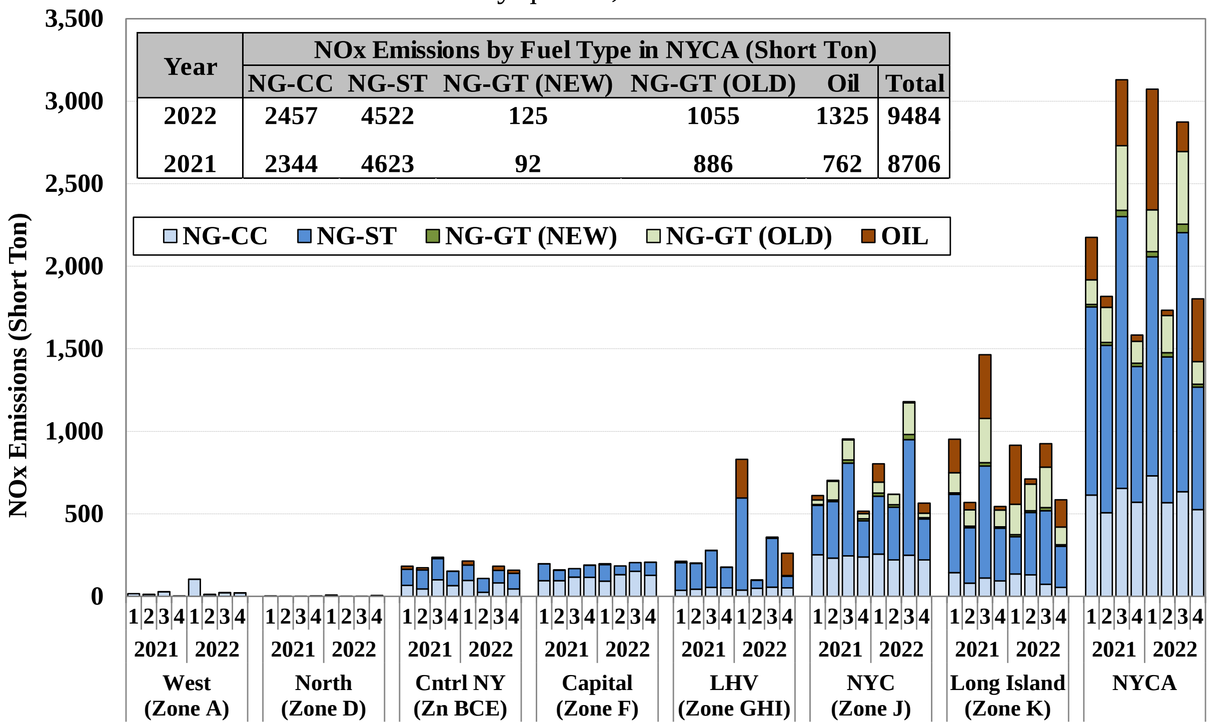
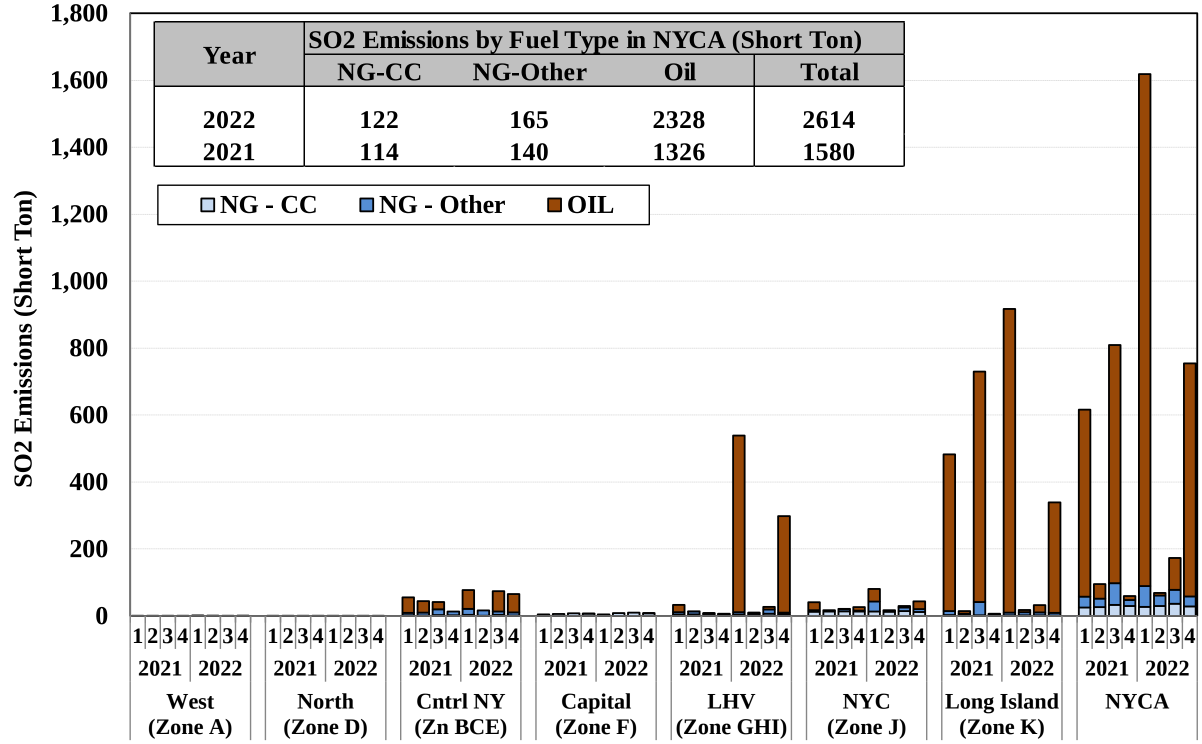


Figure A-13: SO_2 Emissions by Region by Fuel Type
by quarter, 2021-2022



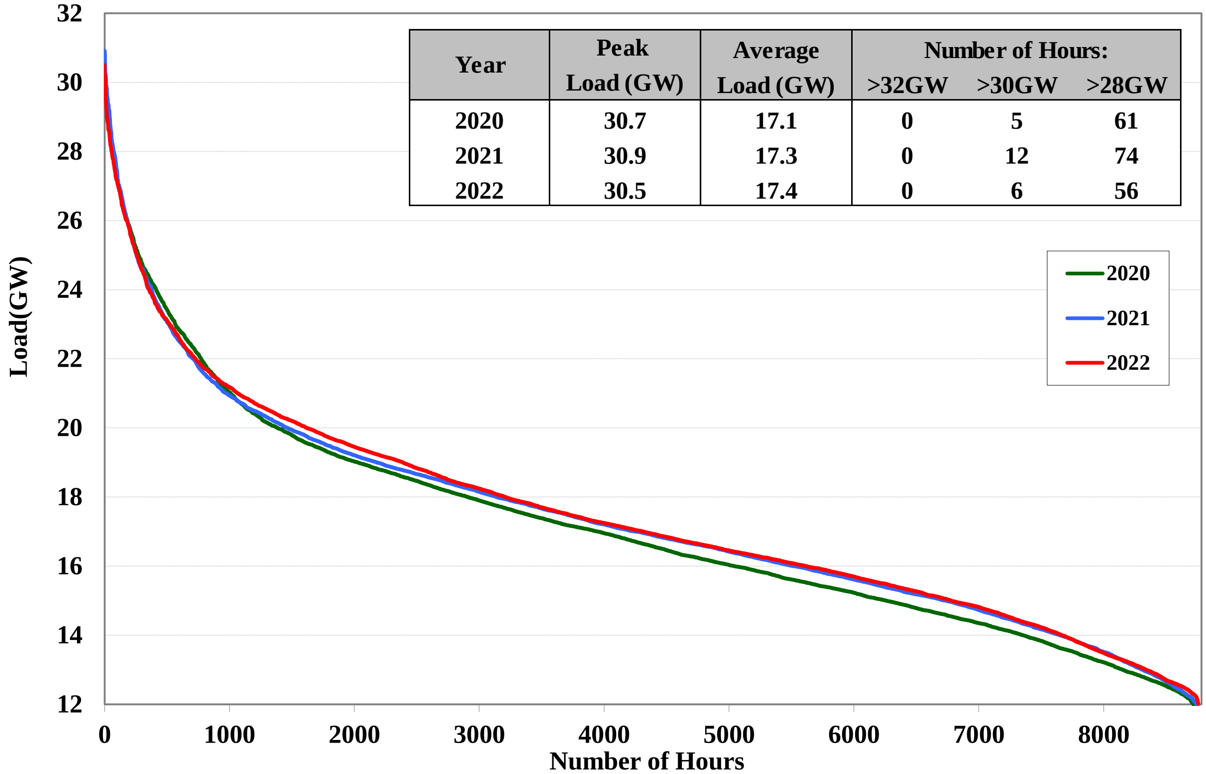
E. Load Levels

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
2020 – 2022



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 2021 and 2022. 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:

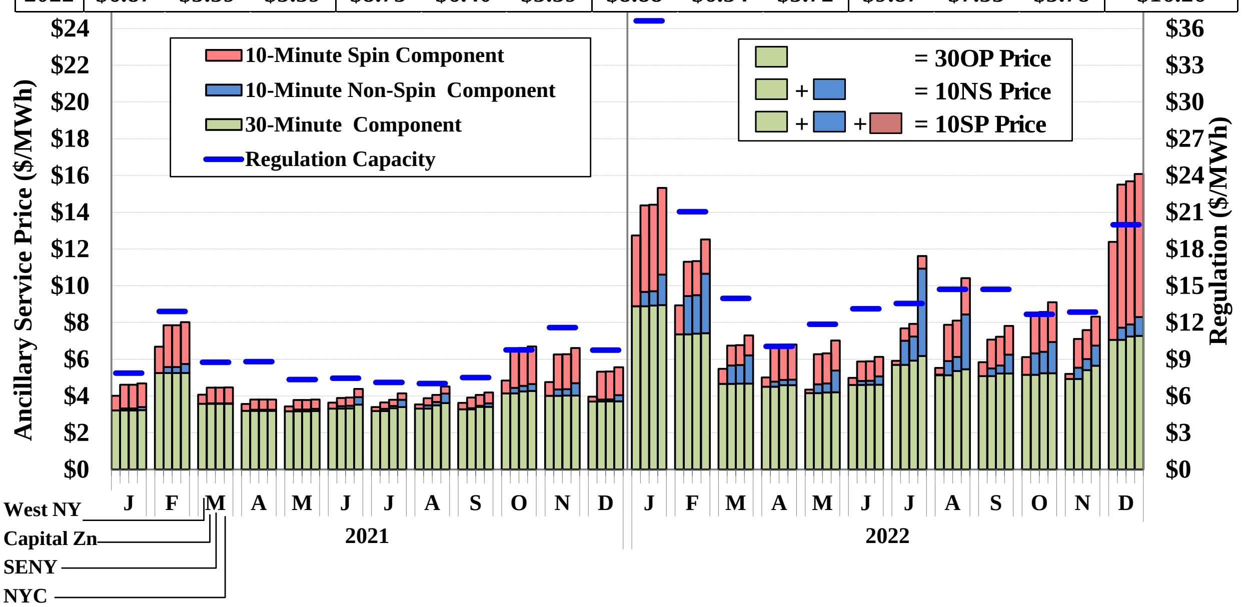
- The 30-minute component represents the cost to simultaneously meet the 30-minute reserve requirements for New York City, Southeast New York, East New York, and NYCA;
- The 10-minute non-spin component represents the cost to simultaneously meet the 10-minute total reserve requirements for New York City, 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 blue dashes give the day-ahead regulation capacity prices for the system. Finally, the inset table compares average final prices (not the components) in 2021 and 2022 on an annual basis.

Figure A-15: Day-Ahead Ancillary Services Prices

2021 - 2022

	West NY			Capital Zone			Southeast NY			New York City			Regulation
Year	10SP	10NS	30OP	10SP	10NS	30OP	10SP	10NS	30OP	10SP	10NS	30OP	
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
2022	$6.87	$5.59	$5.59	$8.75	$6.40	$5.59	$8.88	$6.54	$5.72	$9.87	$7.53	$5.78	$16.26



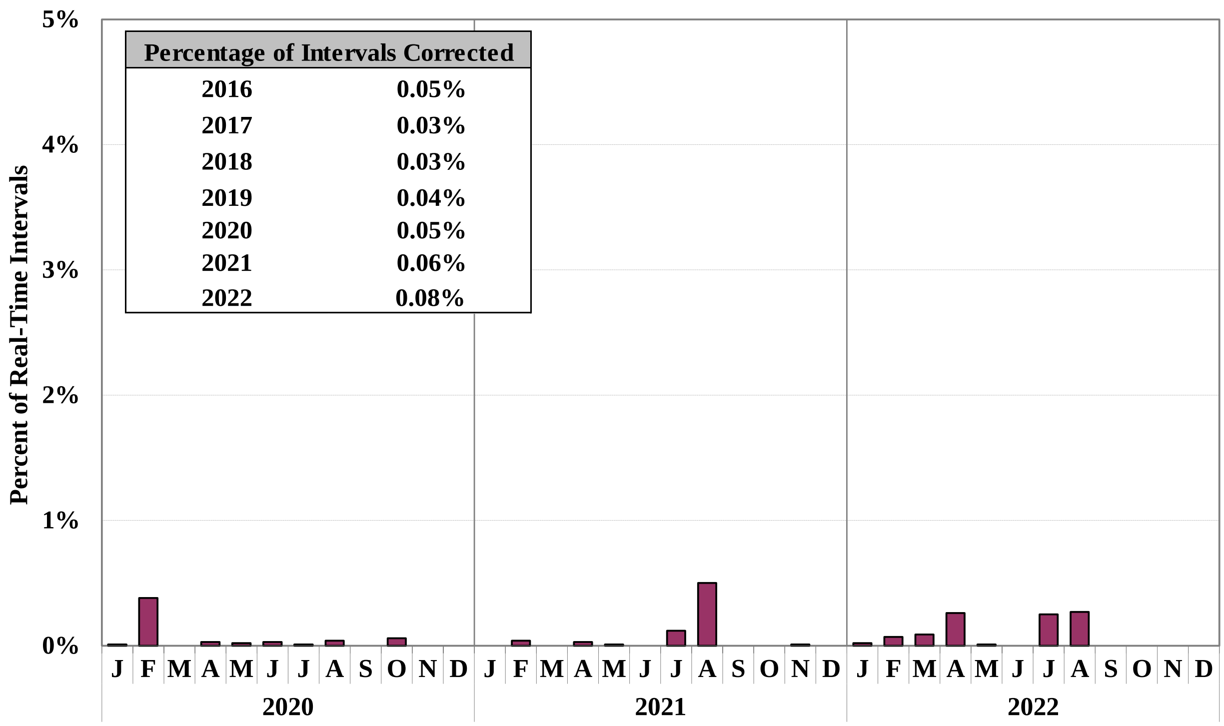
G. Price Corrections

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 2020 to 2022. 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
2020 - 2022



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.

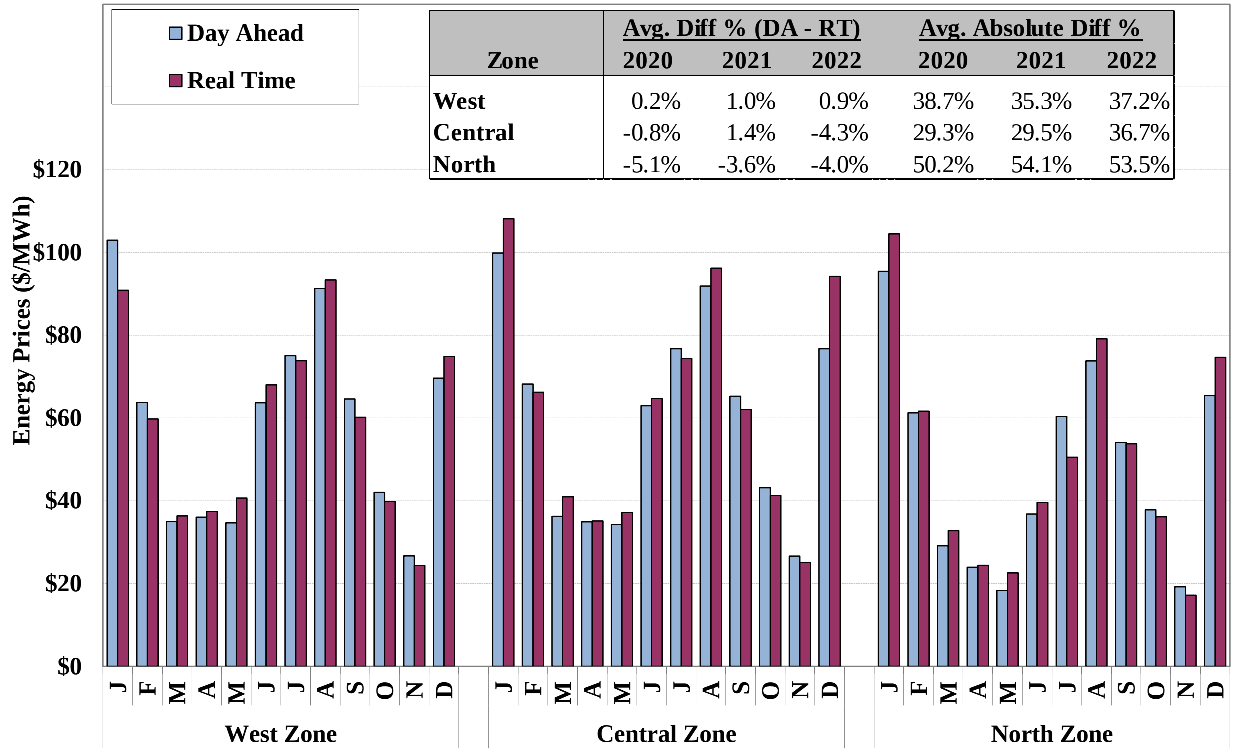
In this section, we evaluate two aspects of convergence in prices between day-ahead and real-time markets and look for evidence of persistent differences. First, we examine the consistency of average day-ahead energy prices with average real-time energy prices at the zone level. Second, we evaluate the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

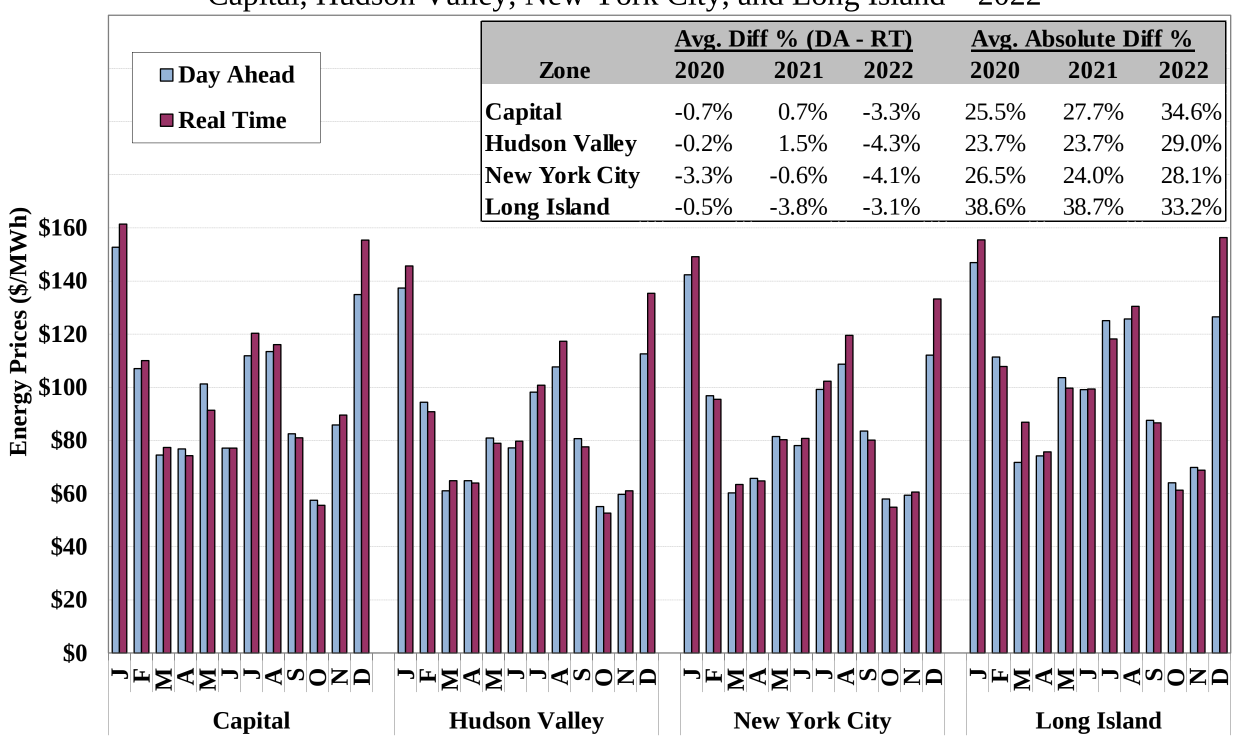
Figure A-17 and Figure A-18 compare day-ahead and real-time energy prices in West Zone, Central Zone, North Zone, Capital Zone, and Hudson Valley, New York City, and Long Island. The figures are intended to reveal whether there are persistent systematic differences between the load-weighted average day-ahead 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 – 2022



Zone	Avg. Diff % (DA - RT) 2020	2021	2022	Avg. Absolute Diff % 2020	2021	2022
West	0.2%	1.0%	0.9%	38.7%	35.3%	37.2%
Central	-0.8%	1.4%	-4.3%	29.3%	29.5%	36.7%
North	-5.1%	-3.6%	-4.0%	50.2%	54.1%	53.5%

Figure A-18: Average Day-Ahead and Real-Time Energy Prices in Eastern New York
Capital, Hudson Valley, New York City, and Long Island – 2022



Zone	Avg. Diff % (DA - RT) 2020	2021	2022	Avg. Absolute Diff % 2020	2021	2022
Capital	-0.7%	0.7%	-3.3%	25.5%	27.7%	34.6%
Hudson Valley	-0.2%	1.5%	-4.3%	23.7%	23.7%	29.0%
New York City	-3.3%	-0.6%	-4.1%	26.5%	24.0%	28.1%
Long Island	-0.5%	-3.8%	-3.1%	38.6%	38.7%	33.2%

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 2021 and 2022. 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. The inset tables summarize the following annual averages in 2021 and 2022: (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
2021 – 2022

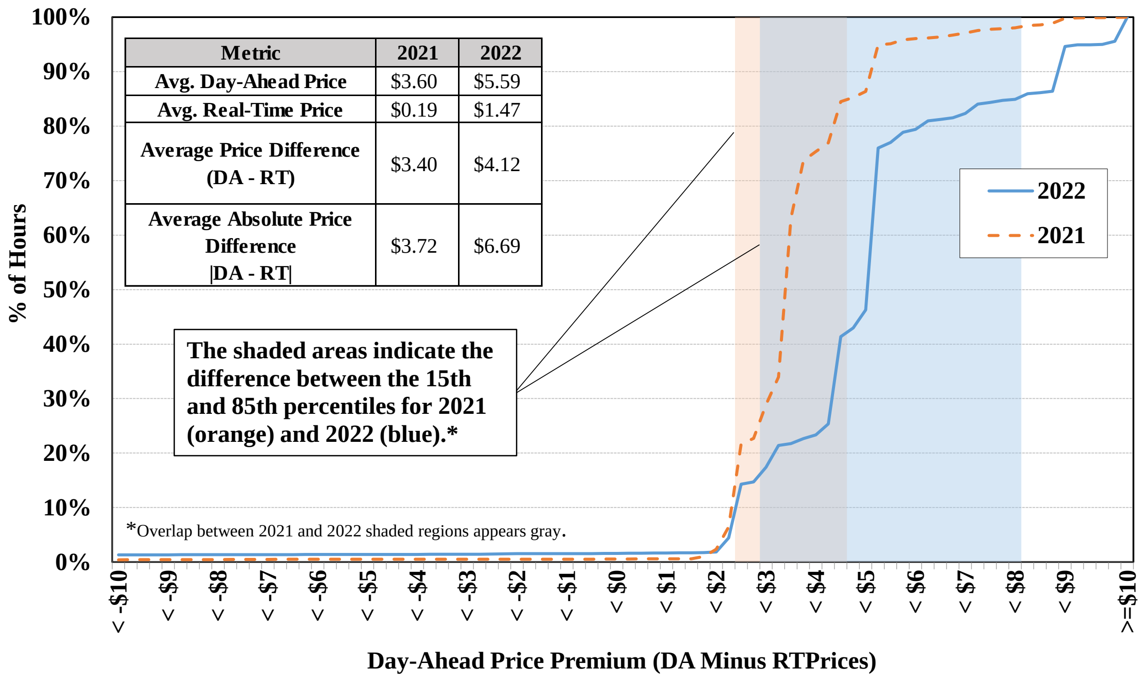


Figure A-20: Day-Ahead Premiums for 10-Minute Spinning Reserves in West New York
2021 – 2022

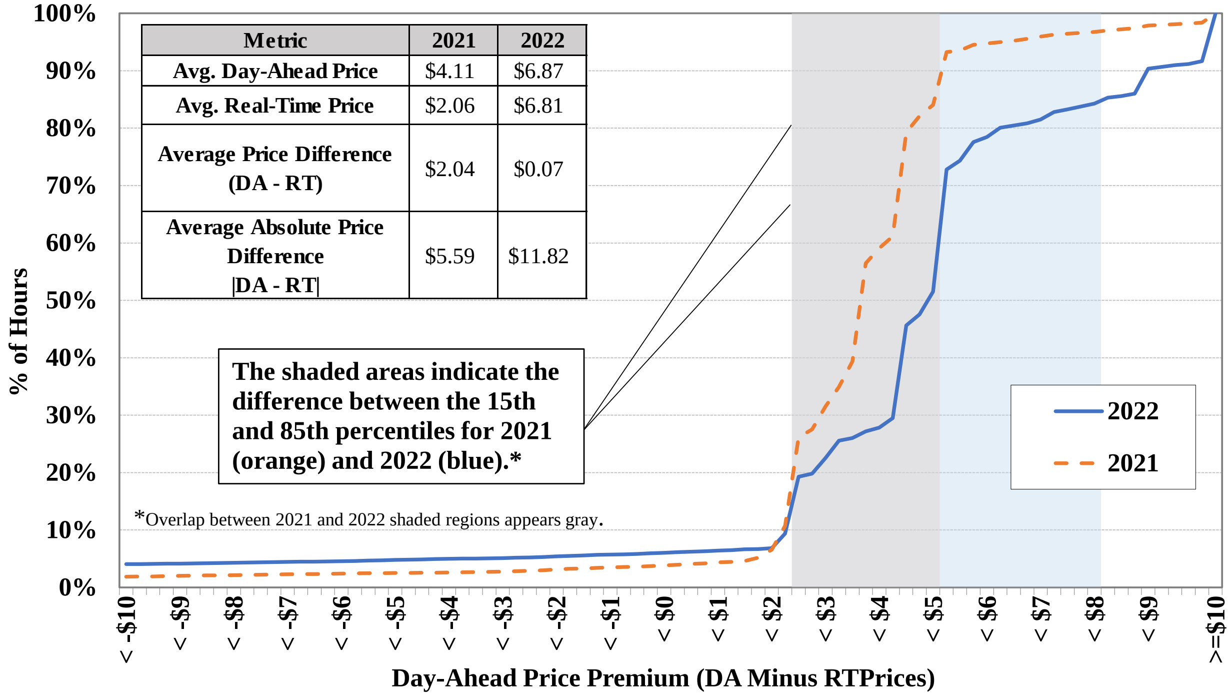


Figure A-21: Day-Ahead Premiums for 10-Minute Spinning Reserves in East New York
2021 – 2022

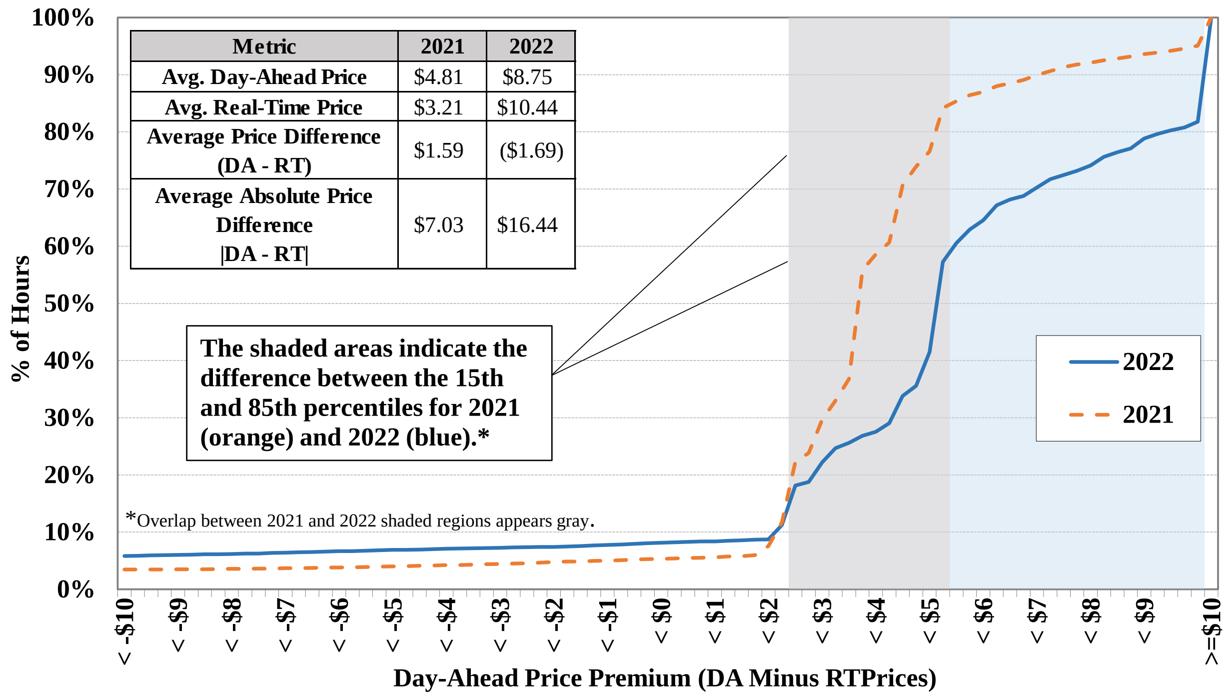


Figure A-22: Day-Ahead Premiums for 10-Minute Non-Spin Reserves in East New York
2021 – 2022

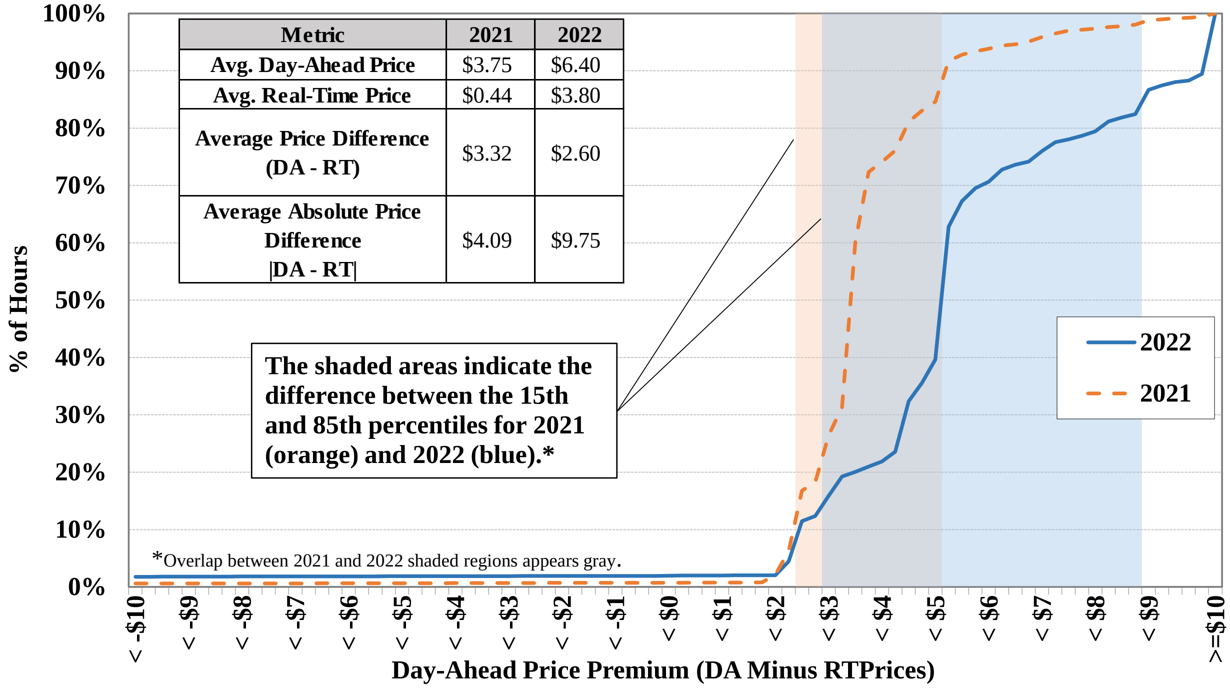


Figure A-23: Day-Ahead Premiums for 30-Minute Reserves in New York City
2021 – 2022

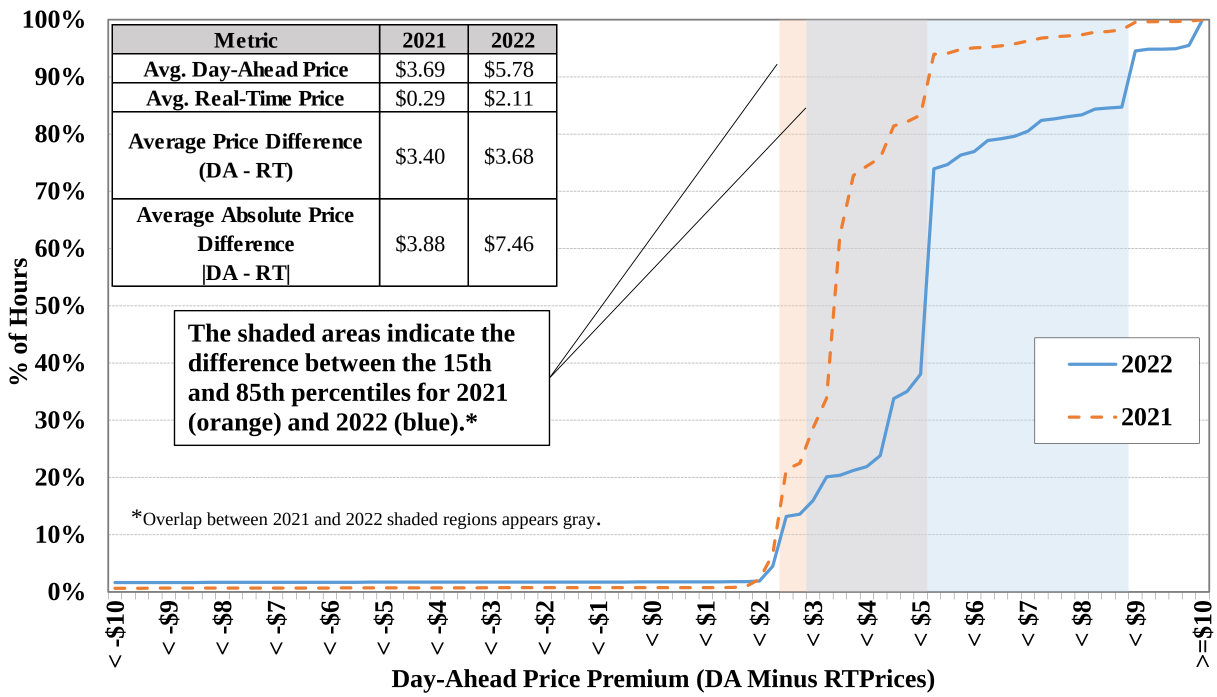


Figure A-24: Day-Ahead Premiums for 10-Minute Spinning Reserves in New York City
2021 - 2022

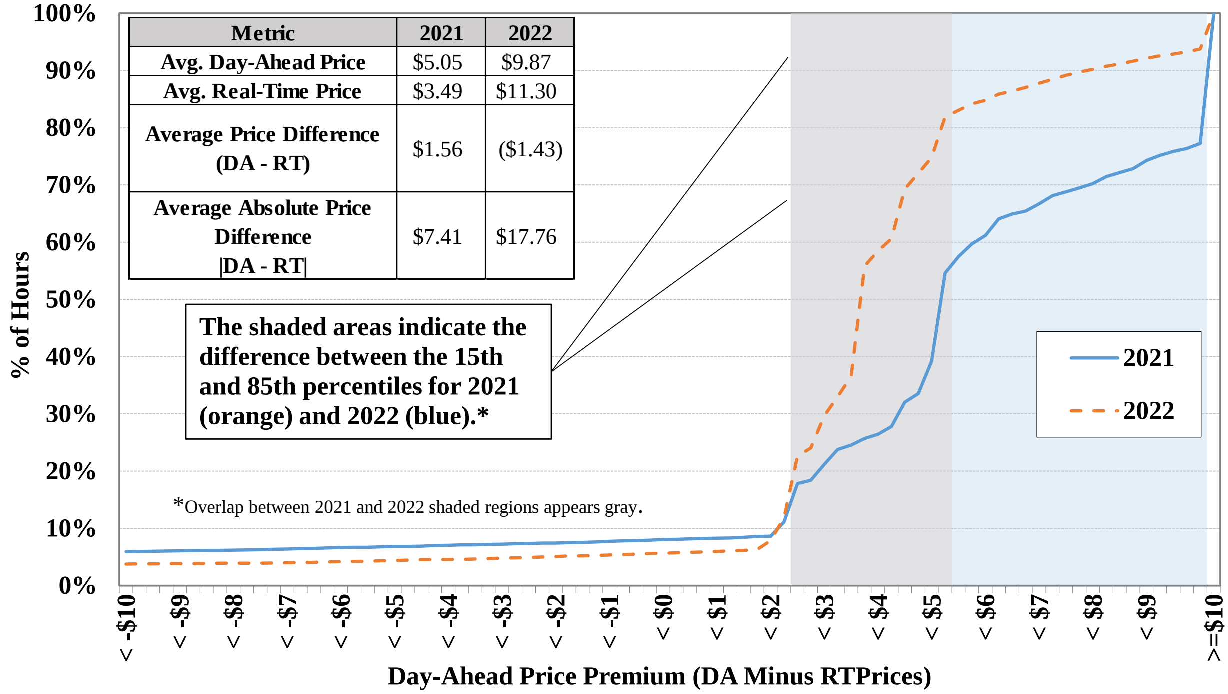
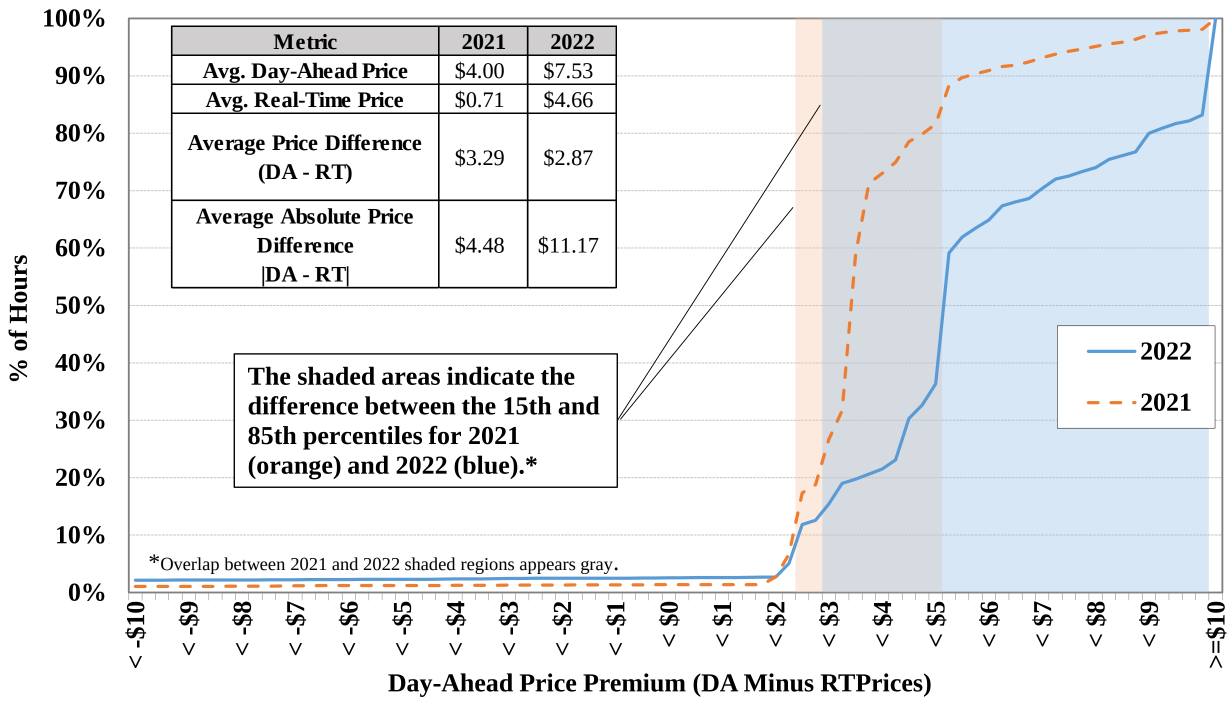


Figure A-25: Day-Ahead Premiums for 10-Minute Non-Spin Reserves in New York City
2021 – 2022



J. Regulation Market Performance

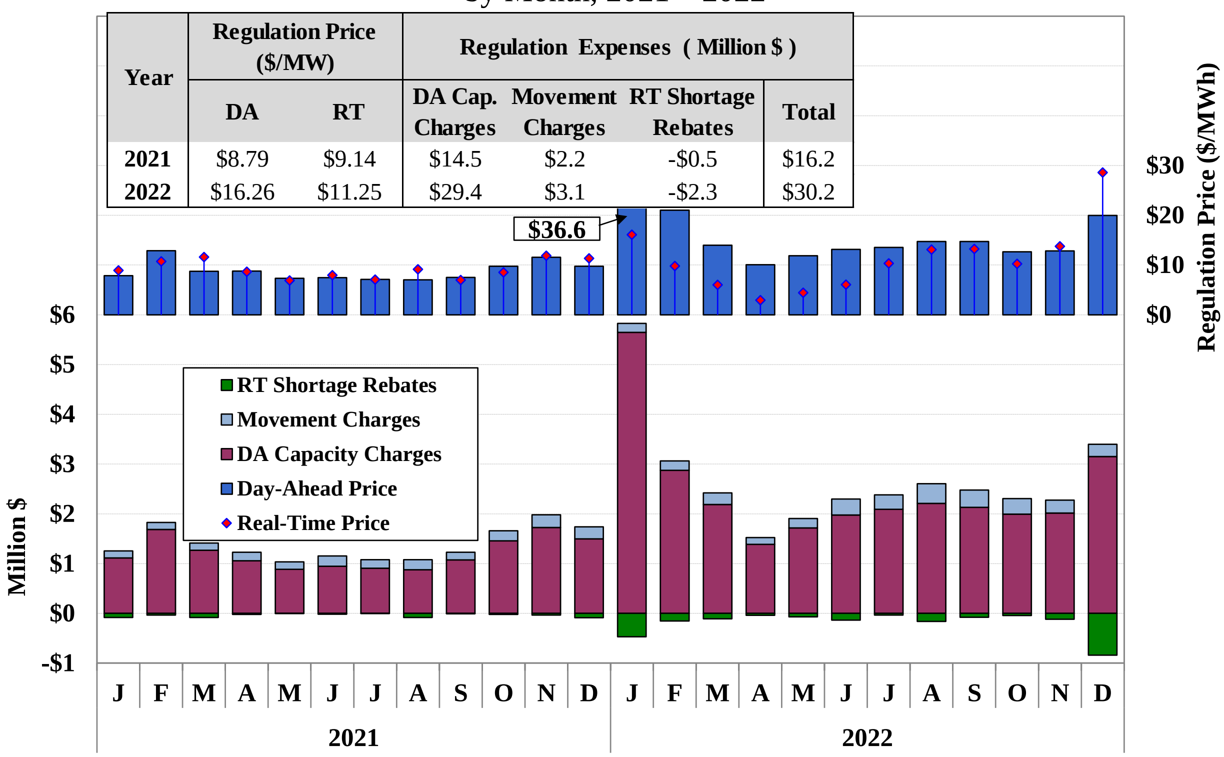
Figure A-26 – Regulation Prices and Expenses

Figure A-26 shows the regulation prices and expenses in each month of 2021 and 2022. The upper portion of the figure compares the regulation prices in the day-ahead and real-time markets.[297] 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, 2021 – 2022

Year	Regulation Price ($/MW)		Regulation Expenses (Million $)			
	DA	RT	DA Cap. Charges	Movement Charges	RT Shortage Rebates	Total
2021	$8.79	$9.14	$14.5	$2.2	-$0.5	$16.2
2022	$16.26	$11.25	$29.4	$3.1	-$2.3	$30.2



297 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.* [298]

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.

298 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.

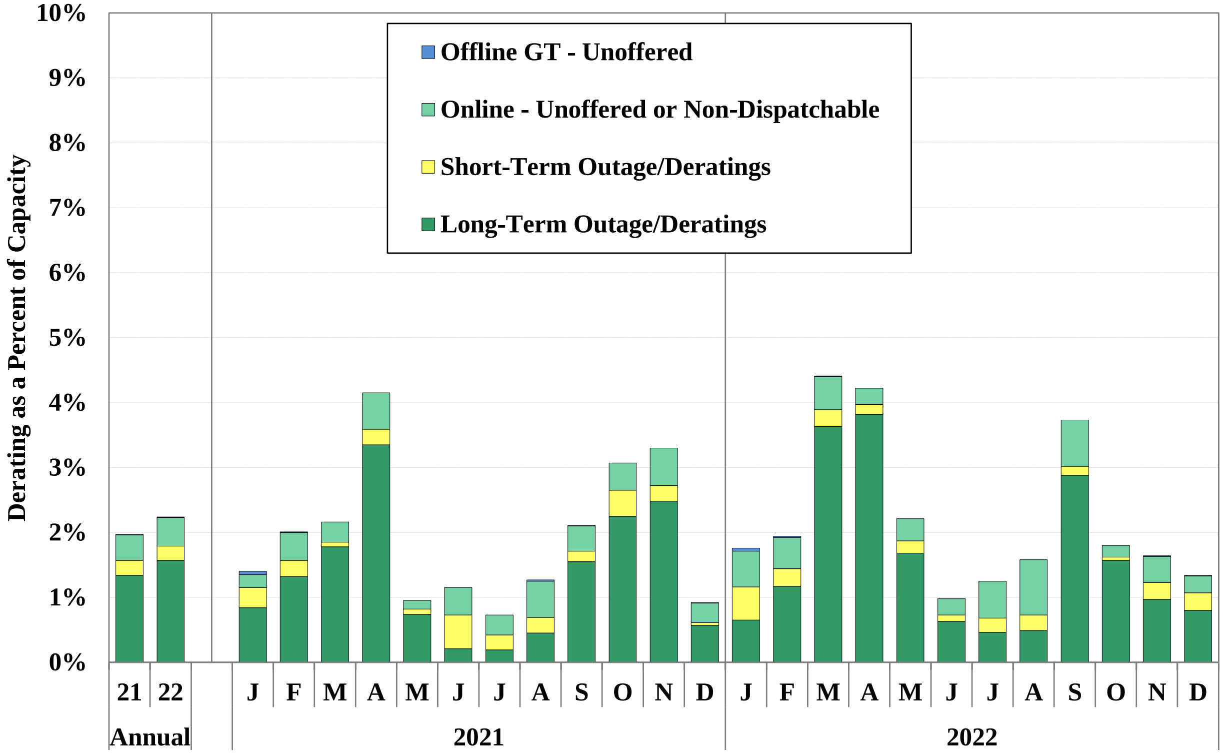
We also focus on economic capacity, since derated and unoffered capacity that is uneconomic does not raise prices above competitive levels and, therefore, is not an indicator of potential withholding.

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.[299] 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.[300] Quick-start units that were economic to commit must have been economic at both forecast RTC prices and settlement RTD prices.[301]

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 2021 and 2022.

Figure A-27: Unoffered Economic Capacity by Month in NYCA
2021 – 2022



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

300 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.

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

Figure A-28: Unoffered Economic Capacity by Month in East New York
2021 - 2022

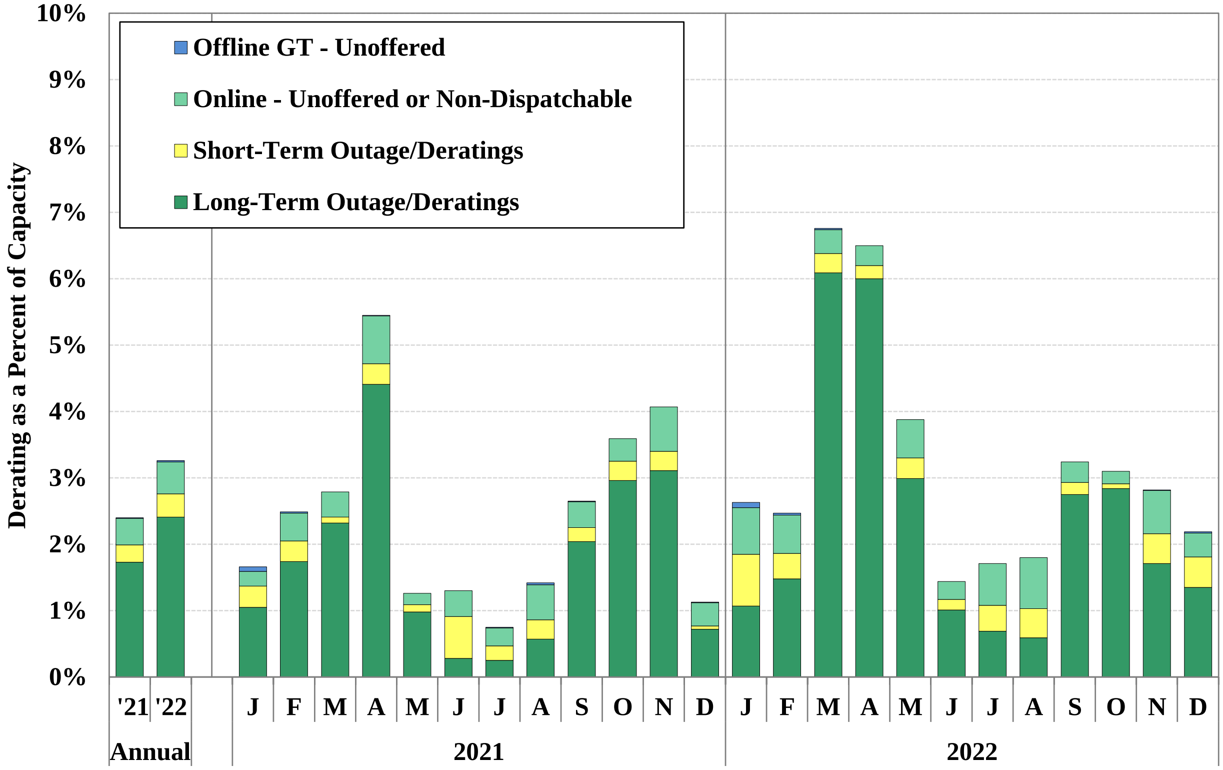


Figure A-29 & Figure A-30: Unoffered Economic Capacity by Load Level & Portfolio Size

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
2021 – 2022

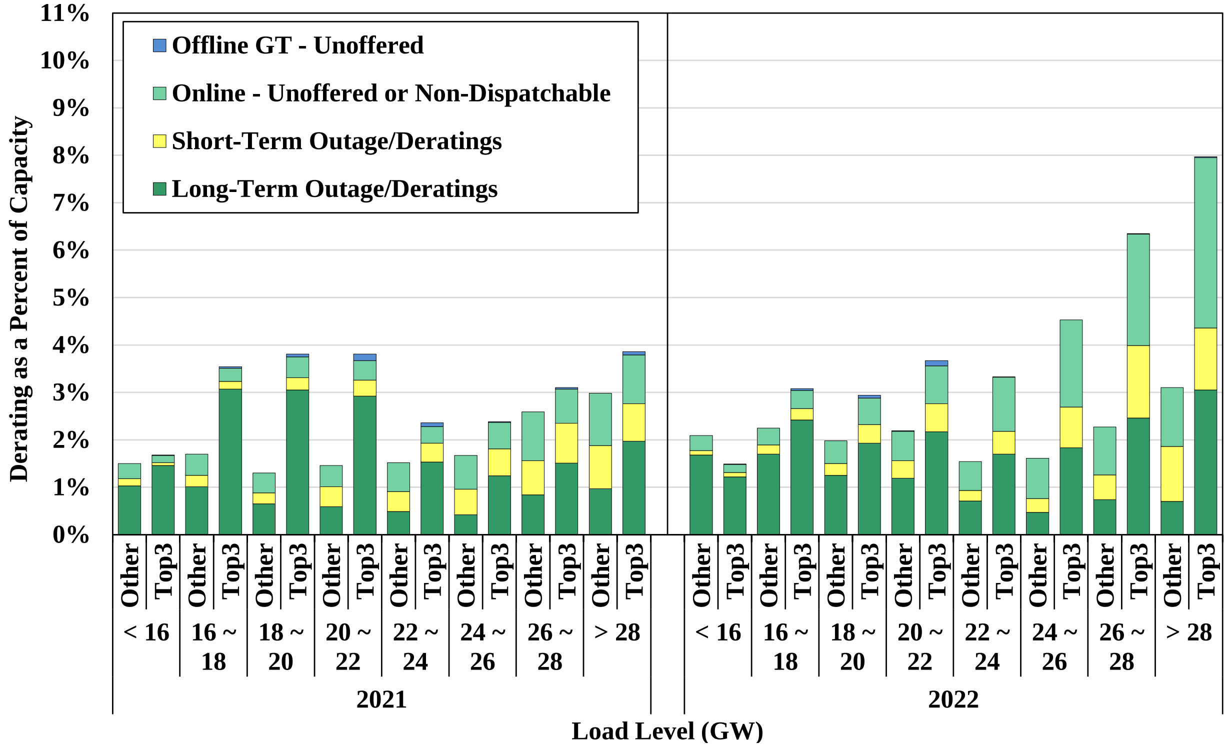
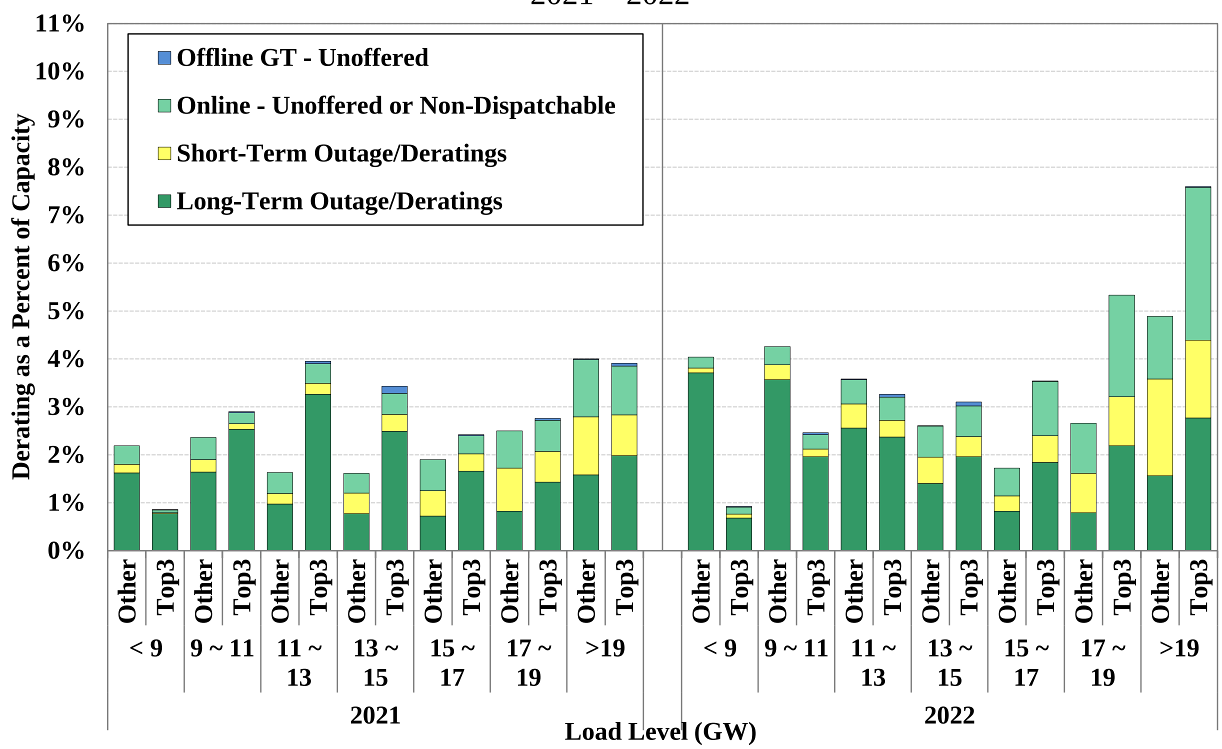


Figure A-30: Unoffered Economic Capacity by Supplier by Load Level in East New York
2021 – 2022



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.[302, 303] 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 appears to be economic at the market clearing price but is not scheduled, either due to bids that exceed the reference levels or due to other factors.[304] 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 thresholds: Threshold 1 is 25 percent of a generator's reference level, and Threshold 2 is 100 percent of a generator's reference level. The two non-mitigation thresholds are included to assess

302 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.

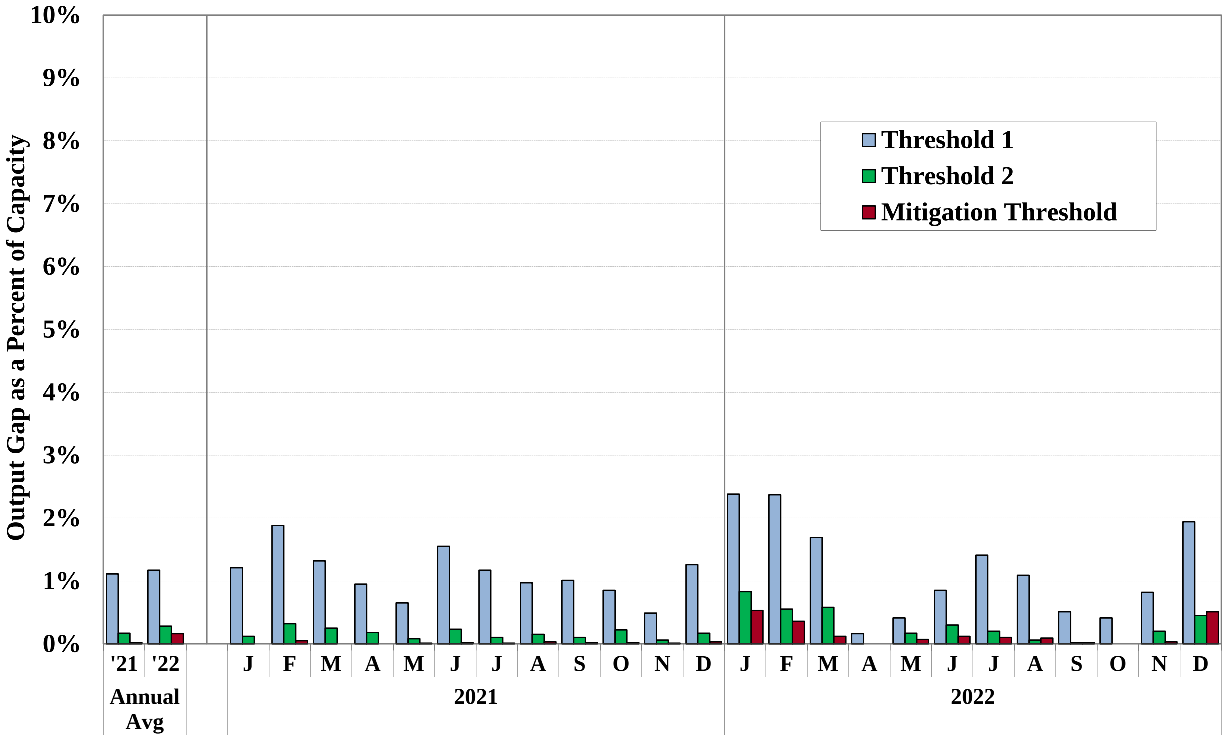
303 Due to the Fuel Cost Adjustment (FCA) functionality, a generator's reference level can be adjusted directly by a generator for a particular hour or day to account for fuel price changes. The NYISO monitors these generator-set FCA reference levels and may request documentation substantiating a generator FCA.

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

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 these thresholds are more likely to flag behavior that is actually competitive.[305]

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
2021 – 2022



305 In most circumstances, Threshold 1 and Threshold 2 are lower thresholds than the Mitigation Threshold. However, it is sometimes the case that the $100 per MWh mitigation threshold is lower than the 100% value of Threshold 2. This is most common during winter period when gas markets are most volatile.

Figure A-32: Output Gap by Month in East New York
2021 - 2022

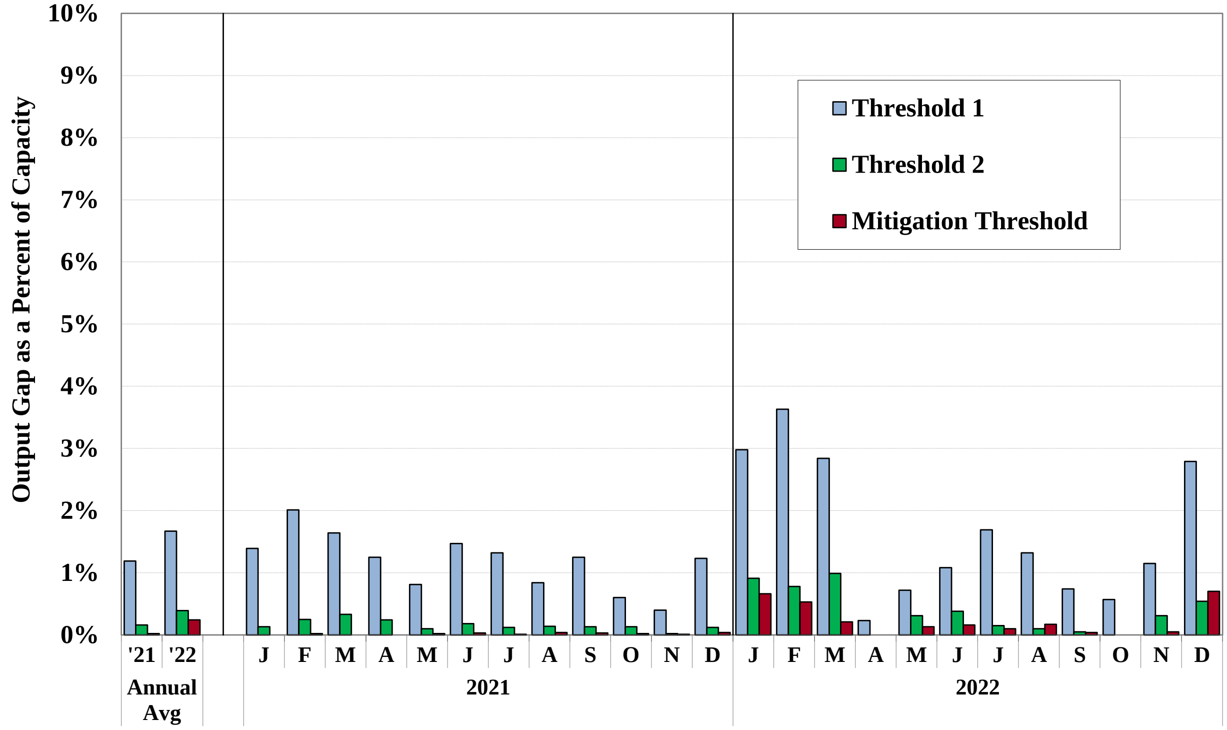


Figure A-33: Output Gap by Supplier by Load Level in New York State
2022

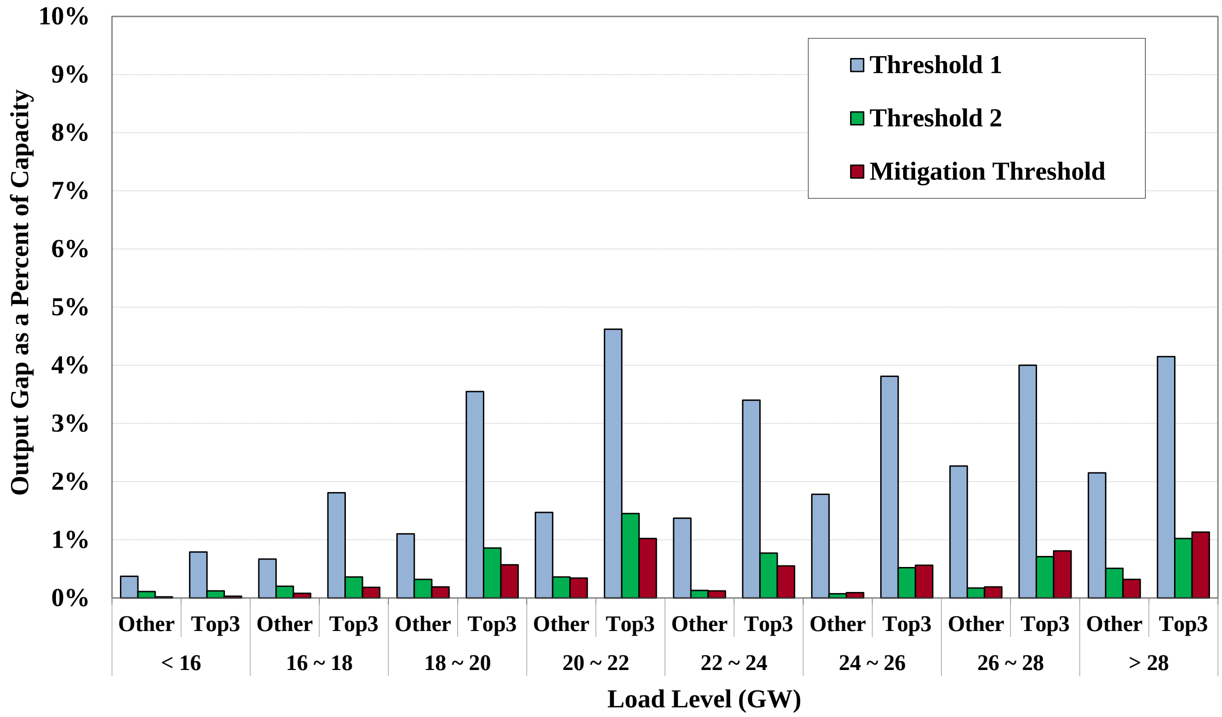
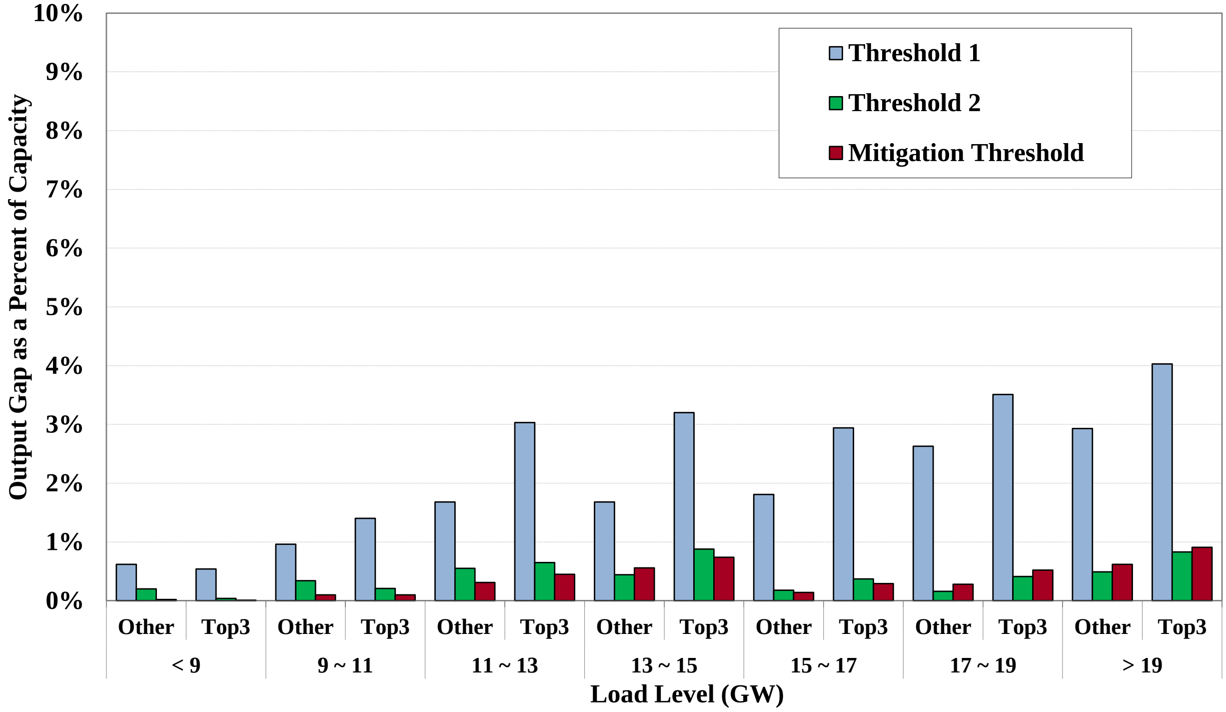


Figure A-34: Output Gap by Supplier by Load Level in East New York
2022



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.[306] 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

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

preceding twelve-month period.[307] 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.[308] 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.[309]

While uncommon, a generator can be mitigated initially in the day-ahead or real-time market and unmitigated after consultation with the NYISO.[310] 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.[311]
- 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 it 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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307 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.

308 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.

309 See NYISO Market Services Tariff, Section 23.3.1.2.3.

310 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.

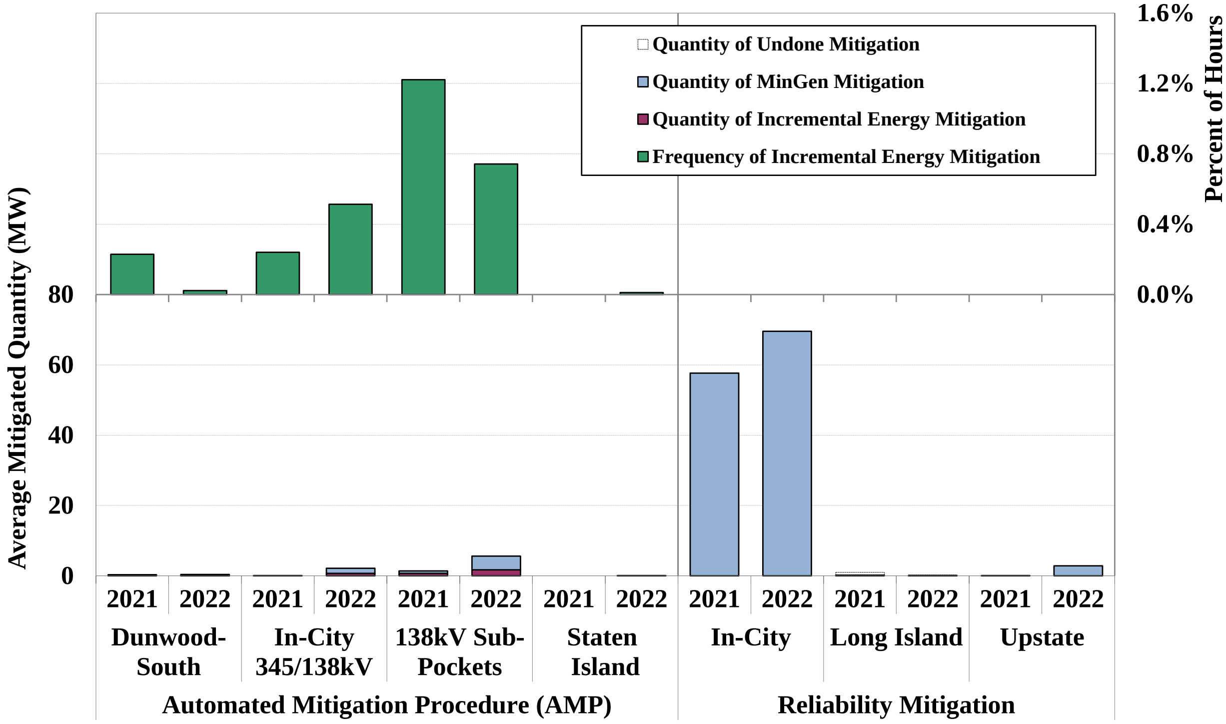
311 The hierarchy of information that is used to calculate reference levels is provided in NYISO Market Services Tariff, Section 23.3.1.4. It is possible for a generator to have a bid-based or LBMP-based reference level that is less accurate than the reference level determined through consultation.

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 2021 and 2022. These figures do not include guarantee payment mitigation that occurs in the settlement system.

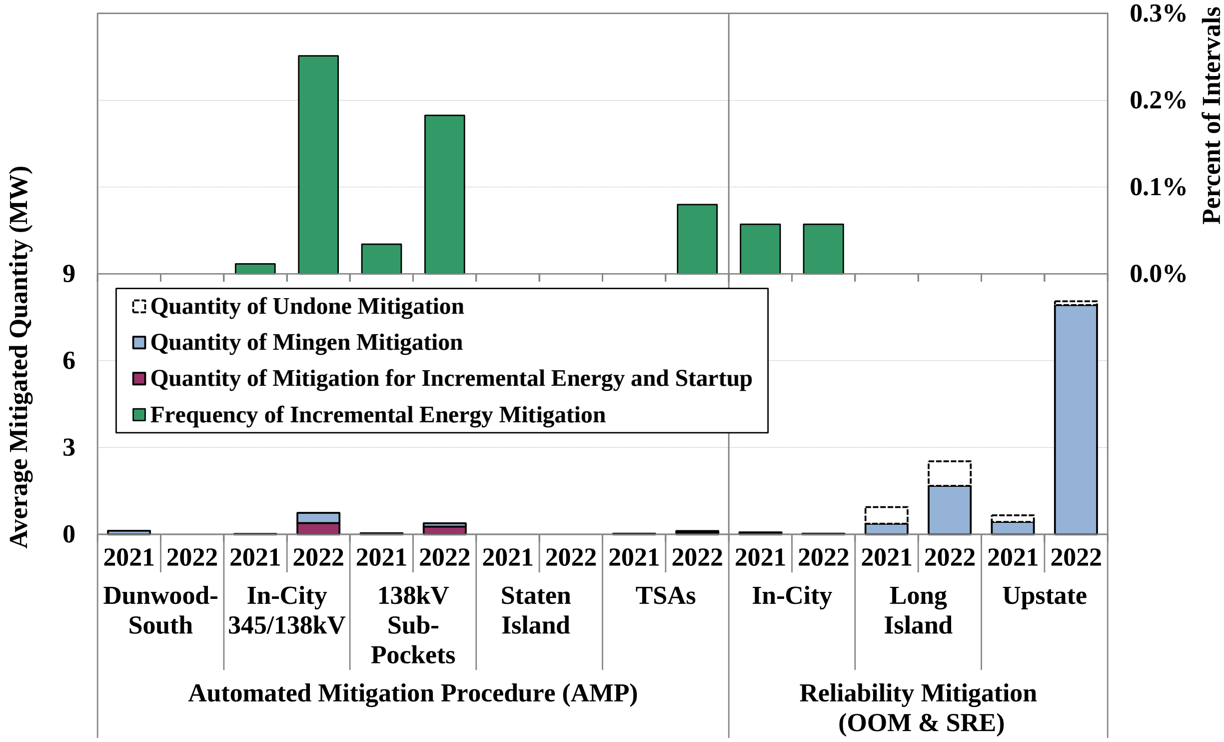
The bars in the upper panel of the figures indicate the percent of hours when incremental energy offer mitigation was imposed on one or more units in each category, while the bars in the lower panel indicate the average amount of capacity mitigated in hours when mitigation occurred (as well as the portion 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).[312] 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
2021 – 2022



312 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
2021 – 2022



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.

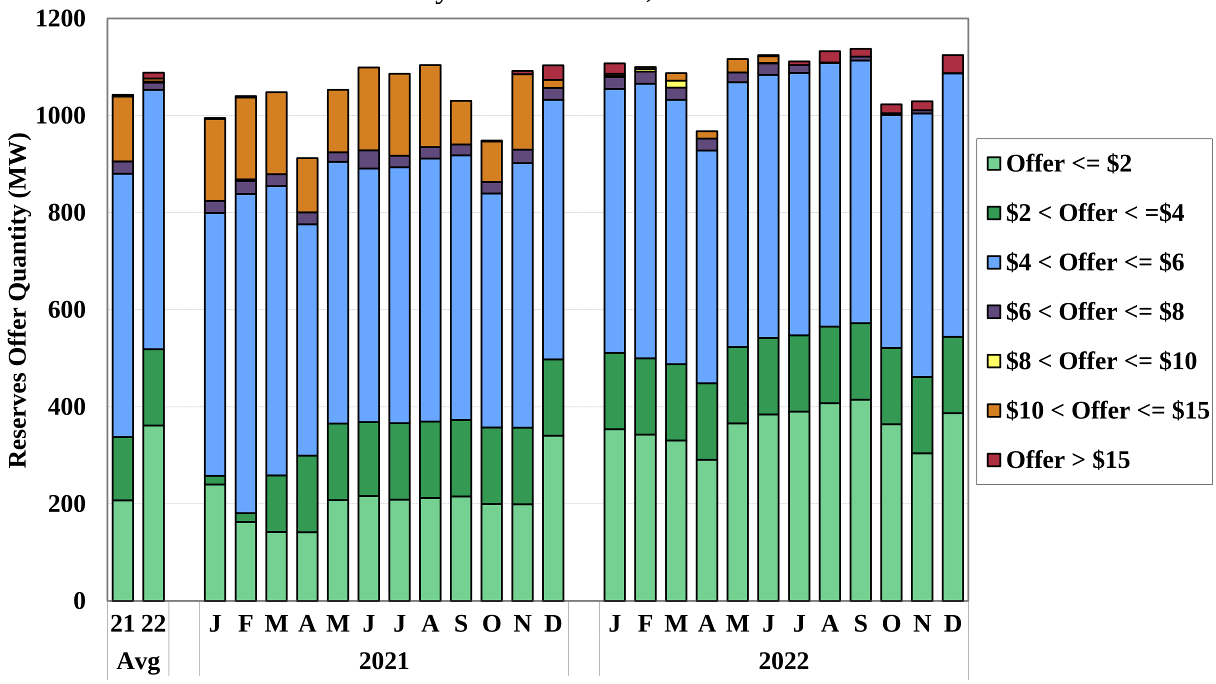
Figure A-37 to Figure A-41: Summary of Day-ahead Ancillary Services Offers

The following figures show ancillary services offers for generators in the day-ahead market for 2021 and 2022 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,[313]
- 30-minute operating reserves in NYCA,[314] and
- Regulation.[315]

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, 2021 – 2022



313 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.

314 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.

315 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, 2021 – 2022

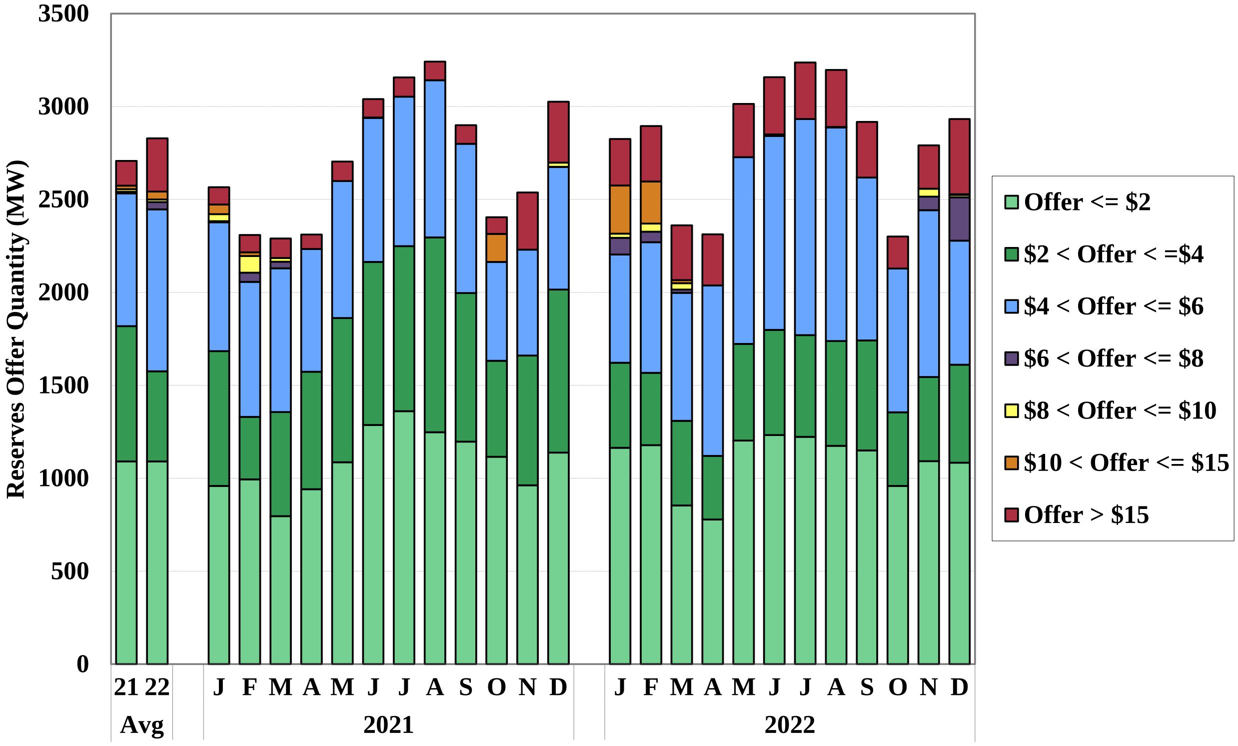


Figure A-39: Summary of East 10-Minute Non-Spin Reserves Offers
Day-Ahead Market, 2021 – 2022

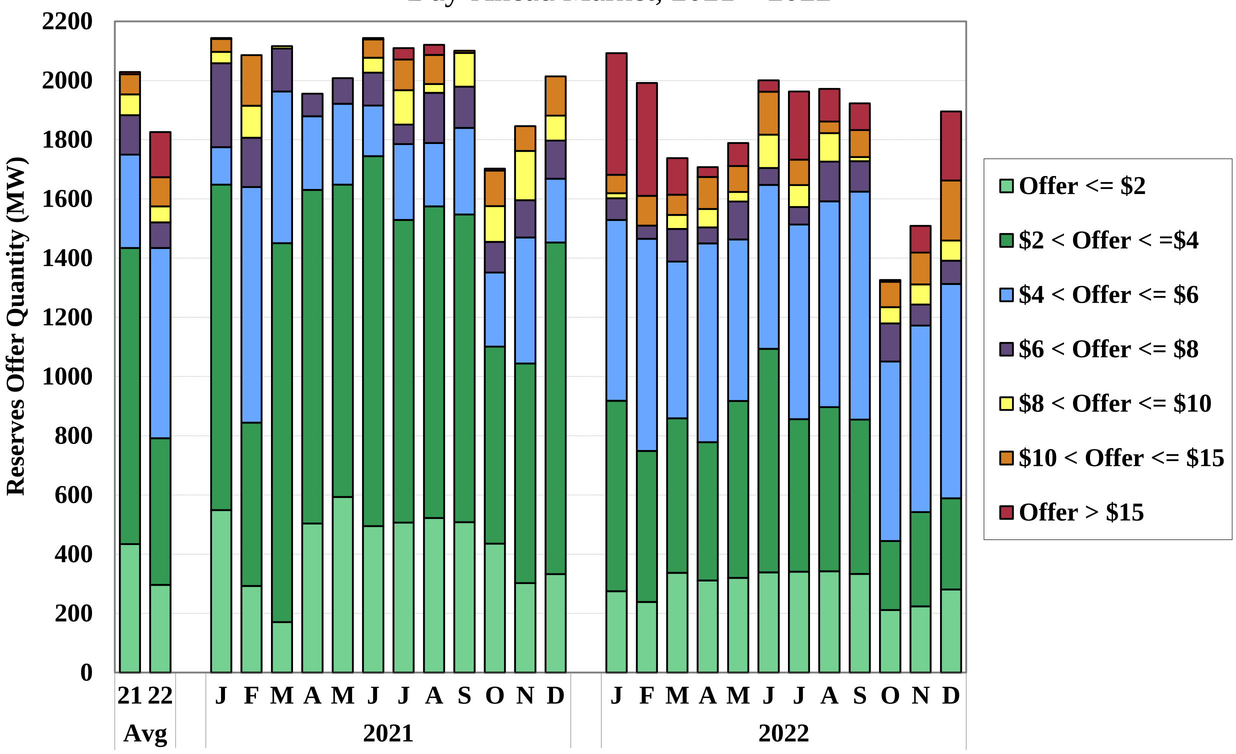


Figure A-40: Summary of NYCA 30-Minute Operating Reserves Offers
Excluding 10-minute, Day-Ahead Market, 2021 – 2022

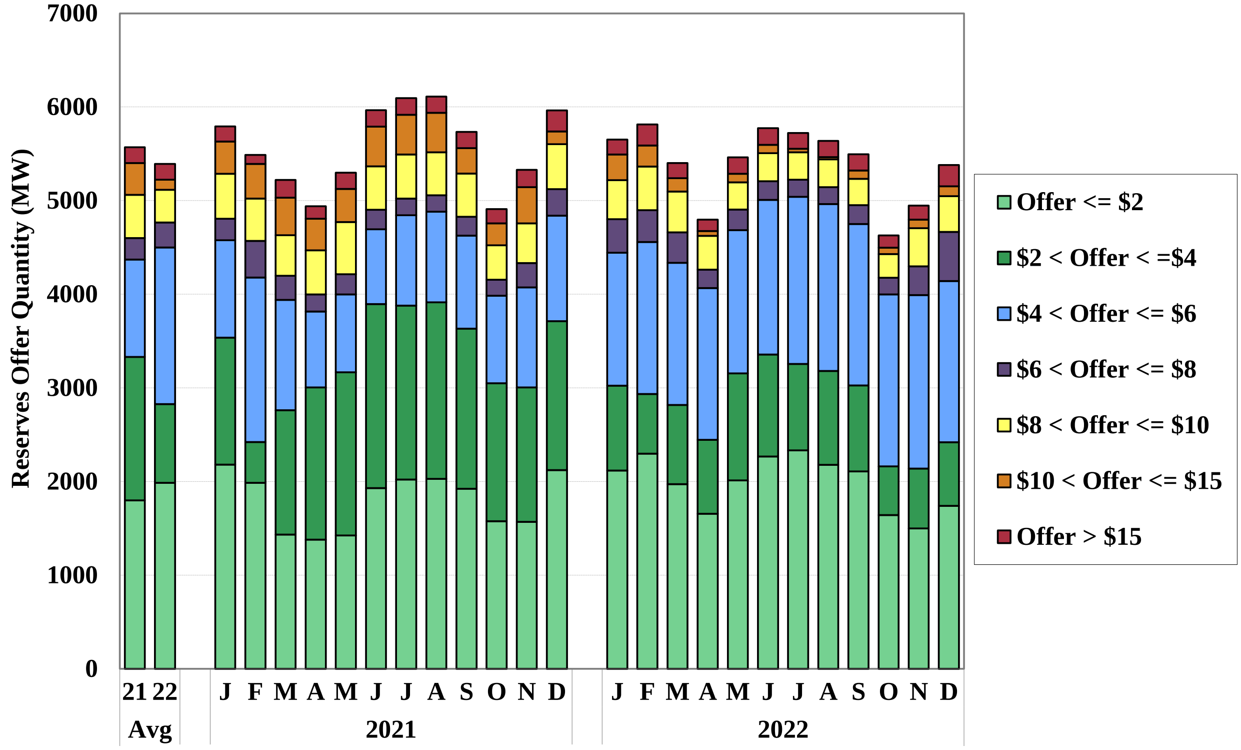


Figure A-41: Summary of Regulation Offers
Day-Ahead Market, 2021 – 2022

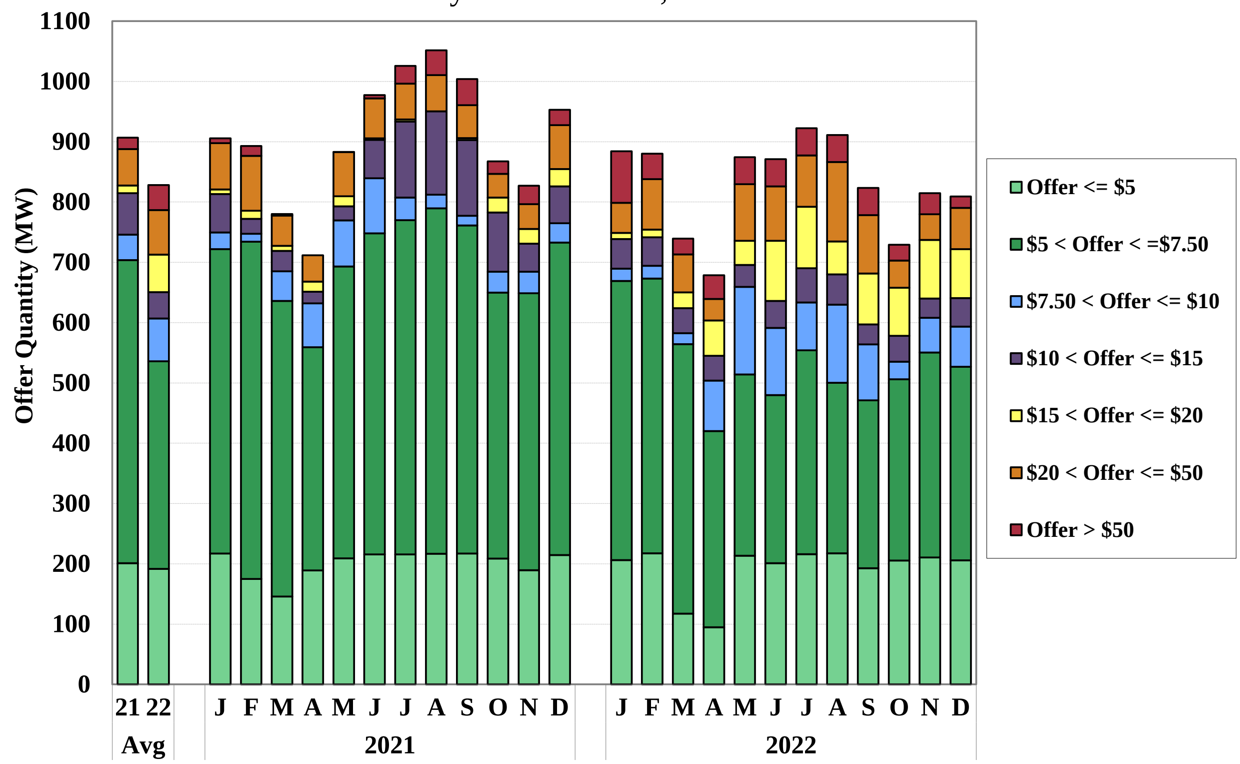


Figure A-42 to Figure A-43: Day-Ahead Reserve Offers That Satisfy NYCA 30-Minute Requirement and NYC Reserve Requirement

Figure A-42 summarizes reserve offers that can satisfy NYCA 30-minute operating reserve requirement in each quarter of 2020 to 2022. 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, 2020 – 2022

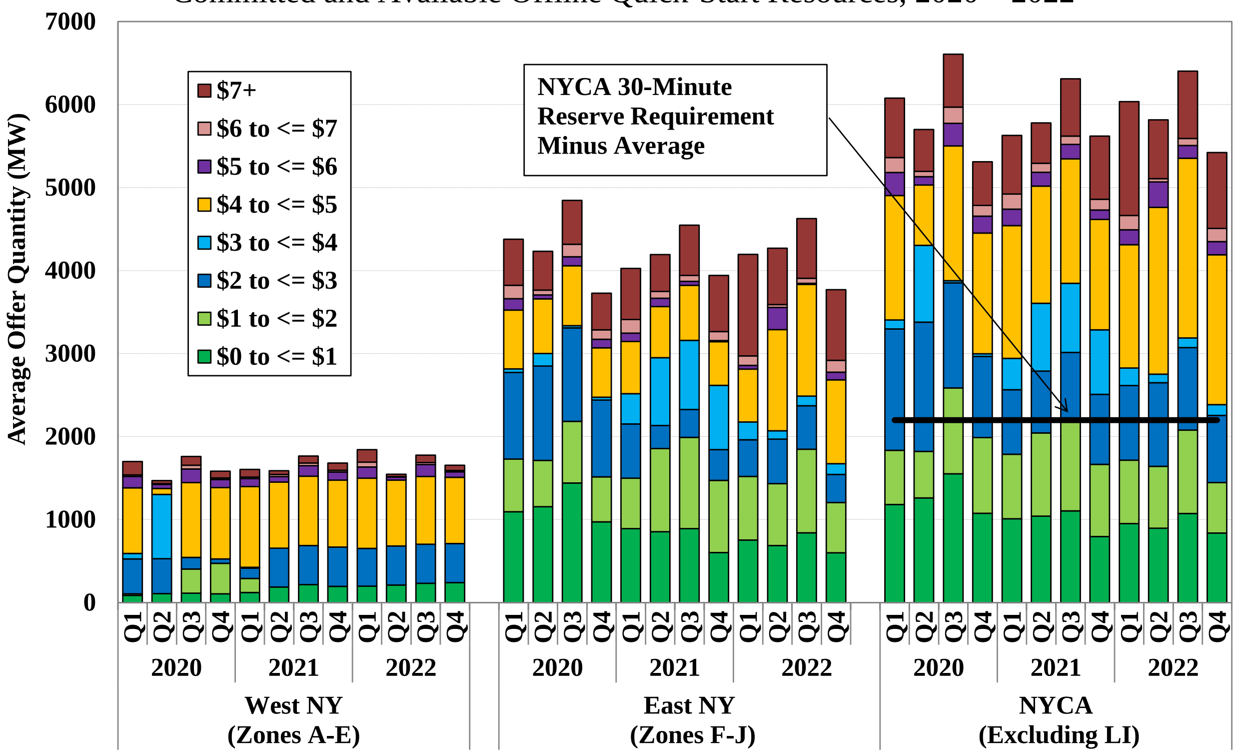


Figure A-43: Day-Ahead Reserve Offers that Satisfy NYC Reserve Requirement

Committed and Available Offline Quick-Start Resources, 2020 - 2022

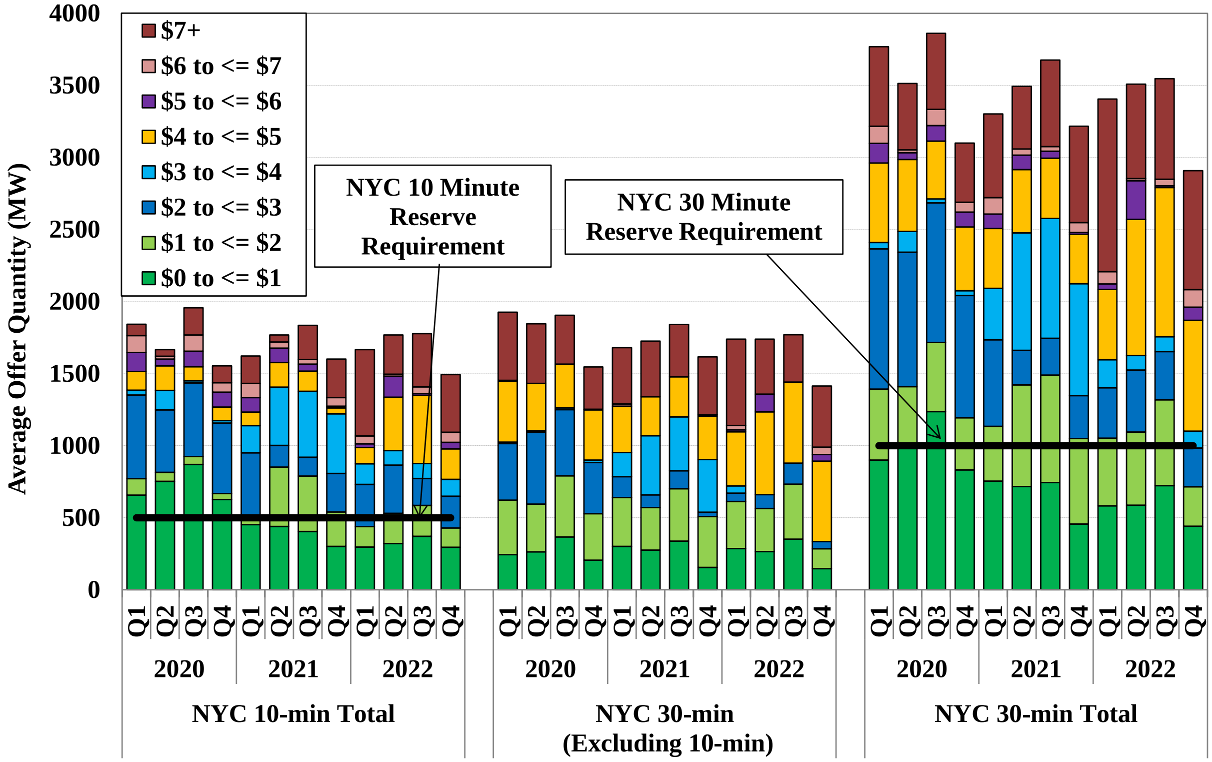


Figure A-43 summarizes offers that can satisfy the new NYC reserves requirement and shows NYC generator offers for 10- and 30-minute reserves from committed resources and available offline quick-start resources. The first set of stacked bars shows the offers from NYC generators for the 10-minute requirement (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.[316]

- *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

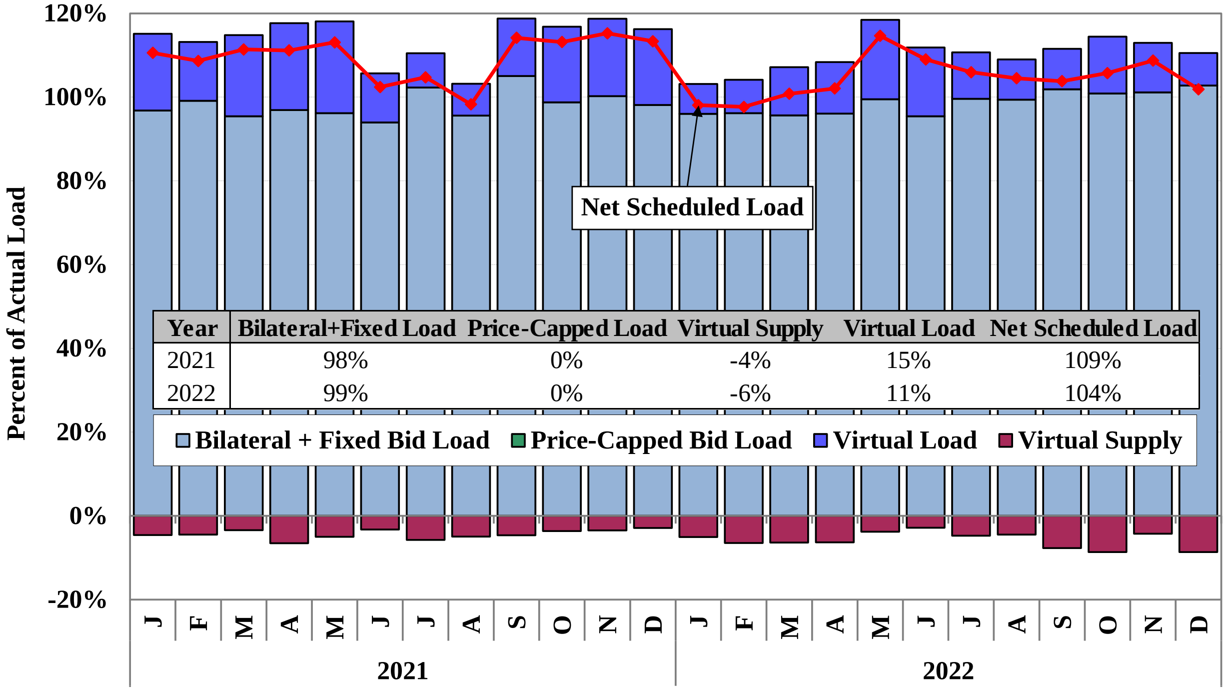
Many generating units have long lead times and substantial commitment costs. Their owners must decide whether to commit them well in advance of real-time before they can be certain that the unit will be economic. The day-ahead market provides these suppliers with a means of being committed only when 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 above real-time prices. Thus, market participants have incentives to schedule amounts of load consistent with real-time load.

[316] 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.

The following eight figures show day-ahead load schedules and bids as a percent of real-time load during daily peak load hours in 2021 and in 2022 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 2021 to 2022. 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, 2021 – 2022



Year	Bilateral+Fixed Load	Price-Capped Load	Virtual Supply	Virtual Load	Net Scheduled Load
2021	98%	0%	-4%	15%	109%
2022	99%	0%	-6%	11%	104%

Figure A-45: Day-Ahead Load Schedules versus Actual Load in Central New York
Zones B, C, & E, 2021 – 2022

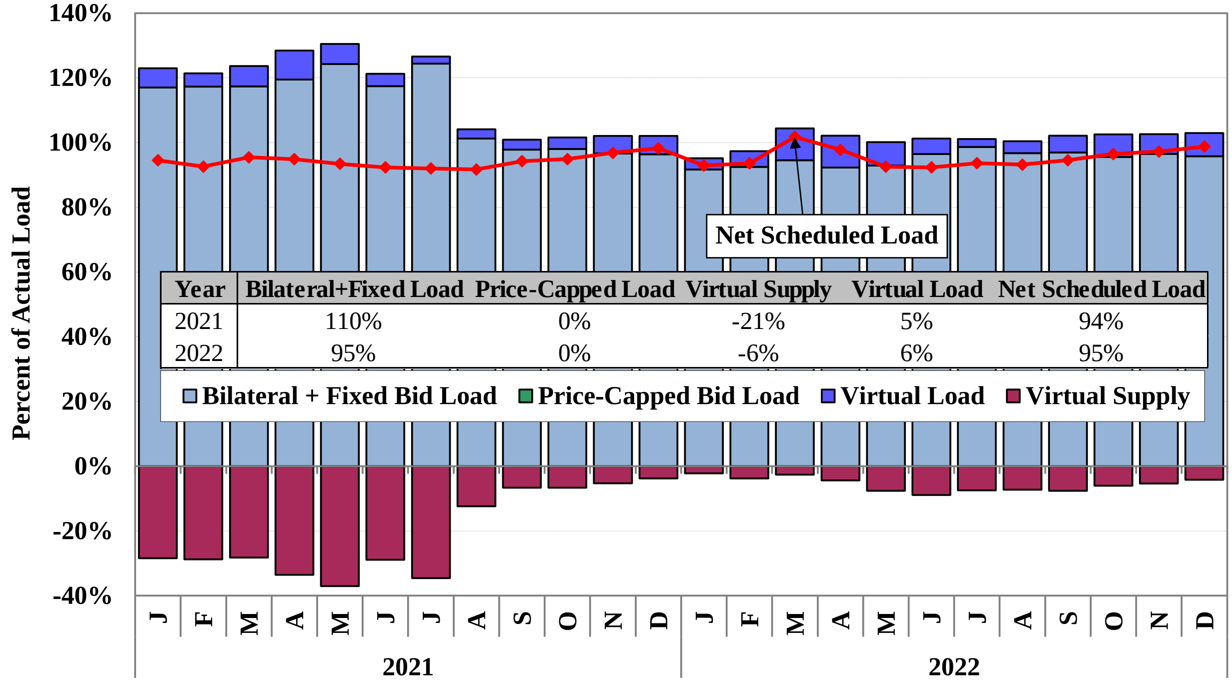


Figure A-46: Day-Ahead Load Schedules versus Actual Load in North Zone
Zone D, 2021 – 2022

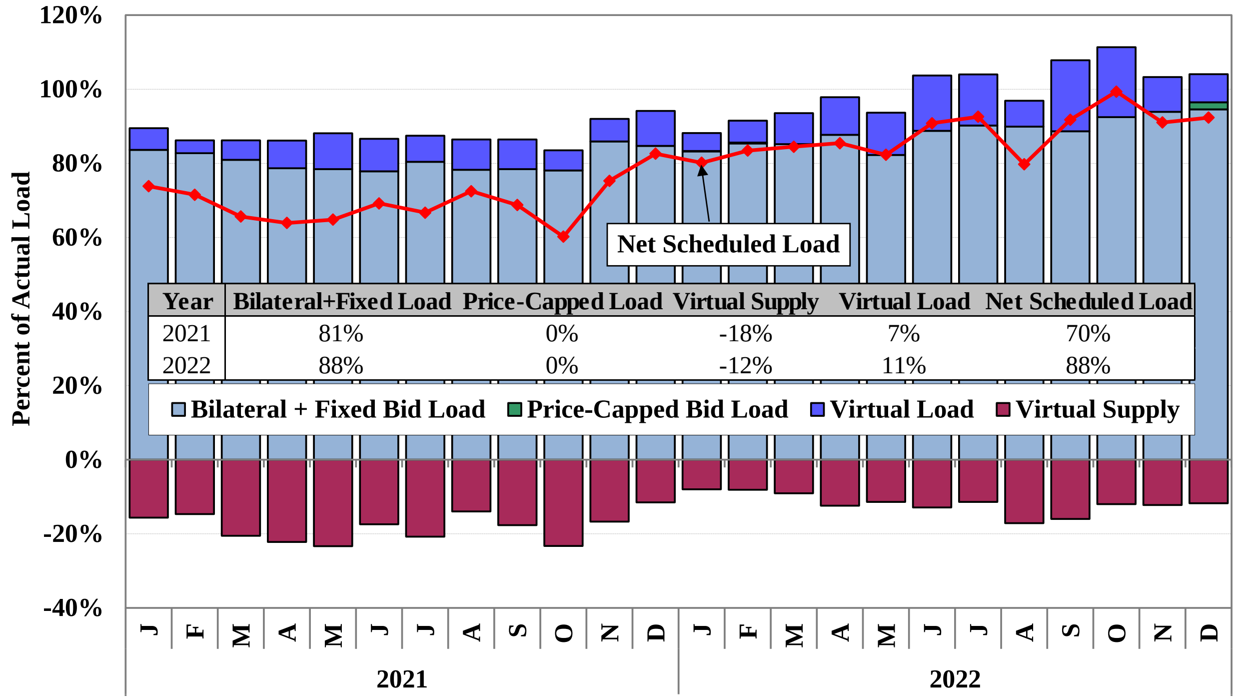
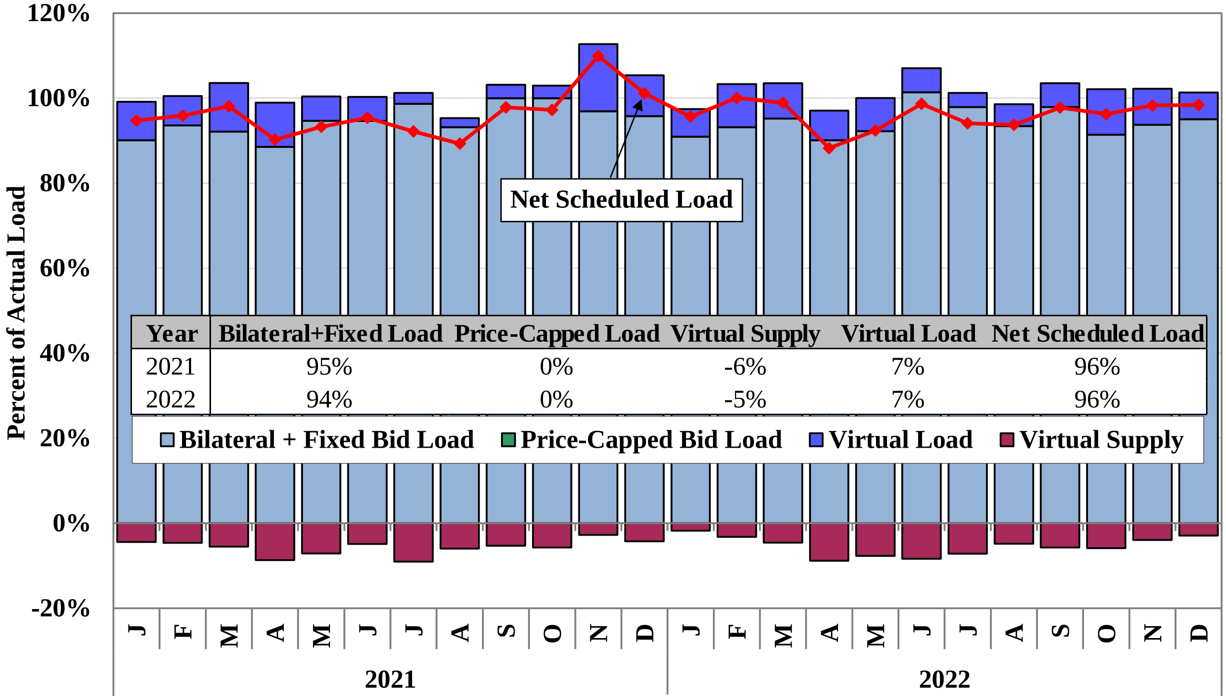
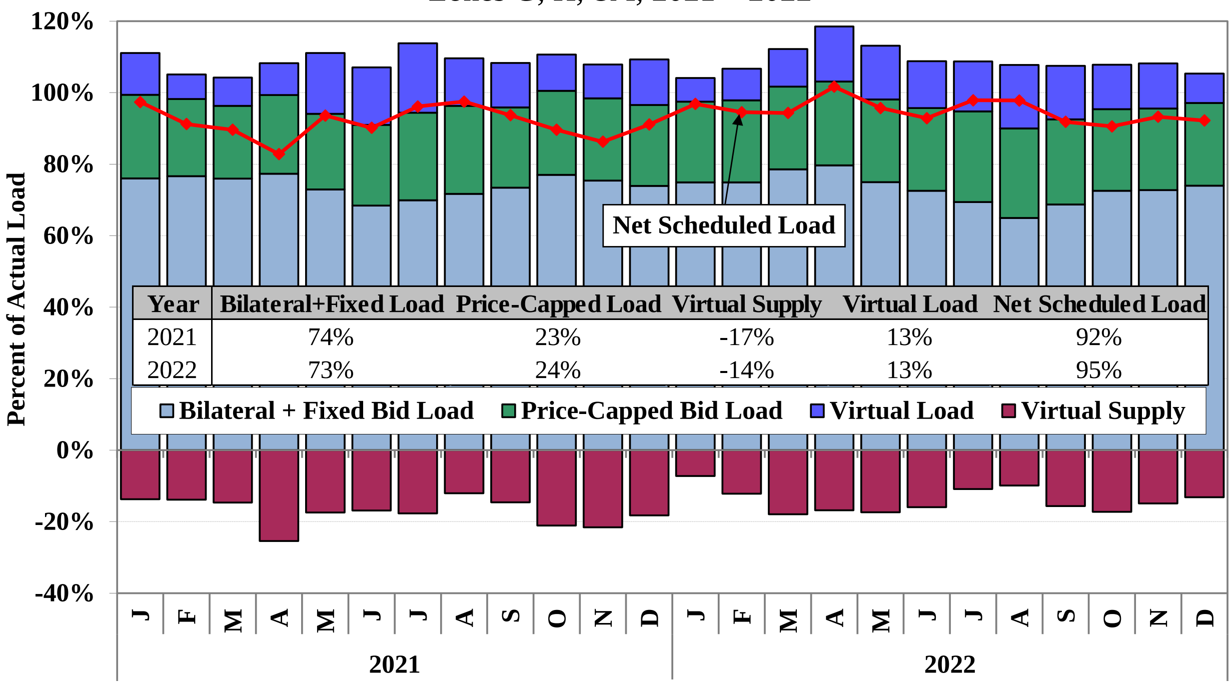


Figure A-47: Day-Ahead Load Schedules versus Actual Load in Capital Zone
Zone F, 2021 – 2022



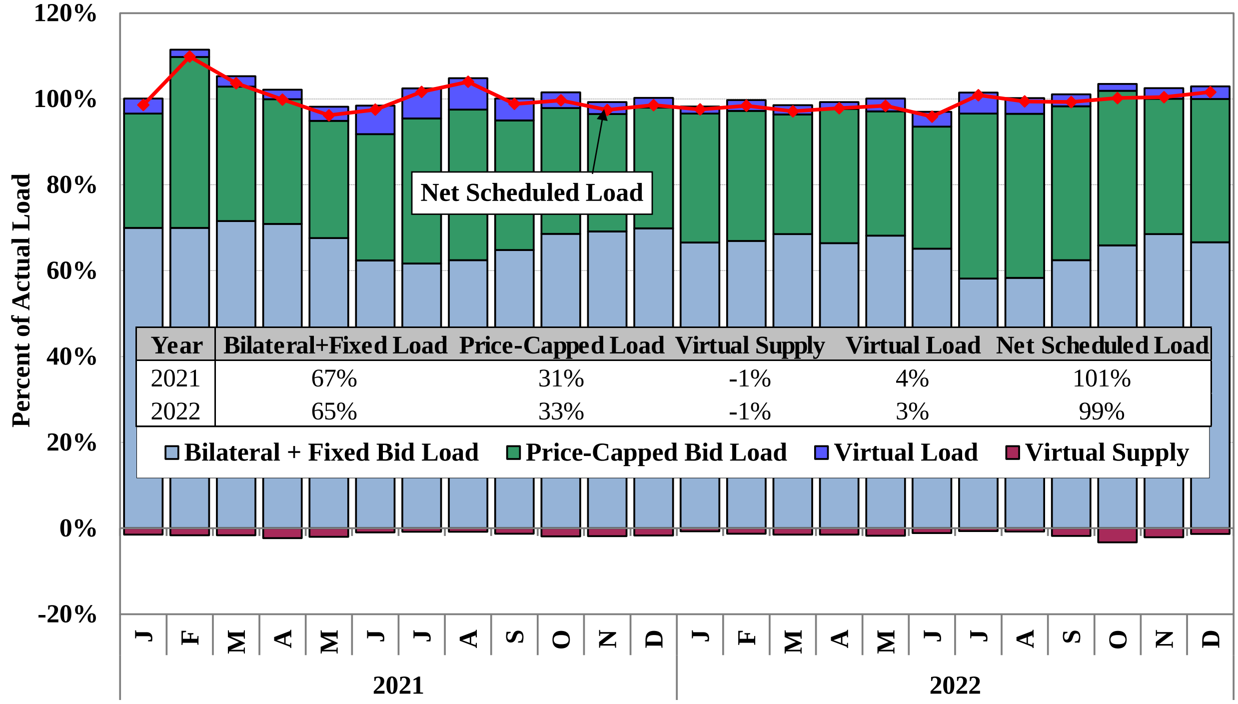
Year	Bilateral+Fixed Load	Price-Capped Load	Virtual Supply	Virtual Load	Net Scheduled Load
2021	95%	0%	-6%	7%	96%
2022	94%	0%	-5%	7%	96%

Figure A-48: Day-Ahead Load Schedules versus Actual Load in the Lower Hudson Valley
Zones G, H, & I, 2021 – 2022



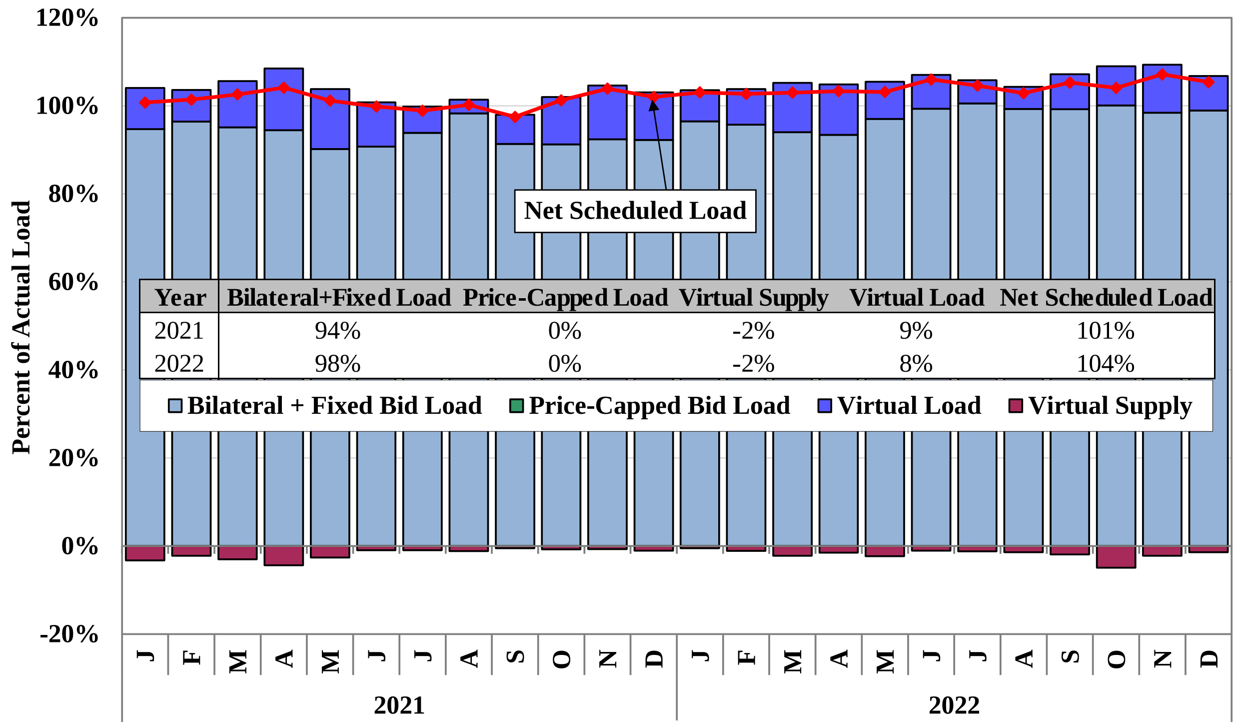
Year	Bilateral+Fixed Load	Price-Capped Load	Virtual Supply	Virtual Load	Net Scheduled Load
2021	74%	23%	-17%	13%	92%
2022	73%	24%	-14%	13%	95%

Figure A-49: Day-Ahead Load Schedules versus Actual Load in New York City
Zone J, 2021 – 2022



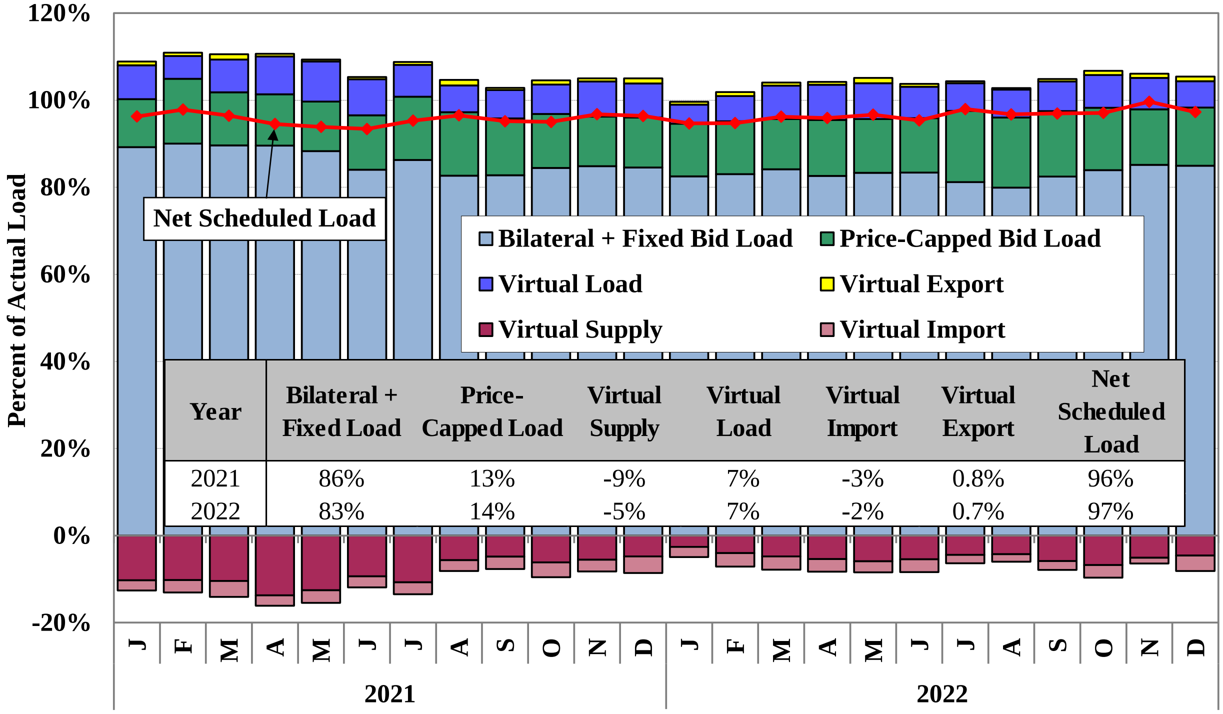
Year	Bilateral+Fixed Load	Price-Capped Load	Virtual Supply	Virtual Load	Net Scheduled Load
2021	67%	31%	-1%	4%	101%
2022	65%	33%	-1%	3%	99%

Figure A-50: Day-Ahead Load Schedules versus Actual Load in Long Island
Zone K, 2021 – 2022



Year	Bilateral+Fixed Load	Price-Capped Load	Virtual Supply	Virtual Load	Net Scheduled Load
2021	94%	0%	-2%	9%	101%
2022	98%	0%	-2%	8%	104%

Figure A-51: Day-Ahead Load Schedules versus Actual Load in NYCA
2021 – 2022



Year	Bilateral + Fixed Load	Price-Capped Load	Virtual Supply	Virtual Load	Virtual Import	Virtual Export	Net Scheduled Load
2021	86%	13%	-9%	7%	-3%	0.8%	96%
2022	83%	14%	-5%	7%	-2%	0.7%	97%

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.

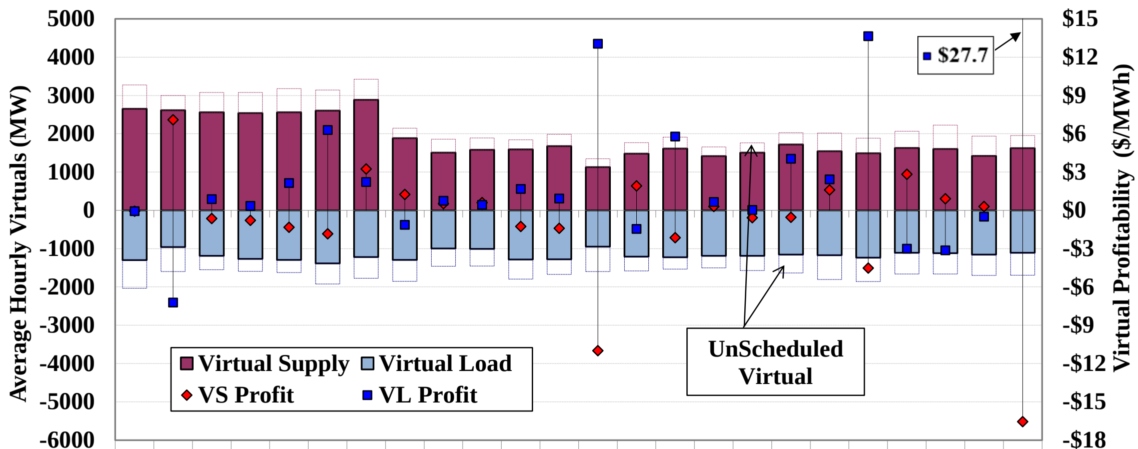
Market participants can schedule virtual-type transactions at the external proxy buses, which are referred to as Virtual Imports and Virtual Exports in this report. These types of external transactions act the same way as the virtual bids placed at the load zones (i.e., the imports and exports that are 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 2021 and 2022. 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.[317,318]

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 296 MW of virtual transactions (or 11 percent of all virtual transactions) netted profits larger than the 50 percent of their zone (or proxy bus) prices in December of 2022. 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
2021 – 2022



			2021												2022											
			J	F	M	A	M	J	J	A	S	O	N	D	J	F	M	A	M	J	J	A	S	O	N	D
Profit > 50% of Avg. Zone Price	MW	MW	320	658	514	549	378	325	413	158	158	96	182	195	225	307	217	291	324	183	228	153	96	134	250	296
	%	%	8%	18%	14%	14%	10%	8%	10%	5%	6%	4%	6%	7%	11%	11%	8%	11%	12%	6%	8%	6%	4%	5%	10%	11%
Loss > 50% of Avg. Zone Price	MW	MW	283	388	491	688	498	271	234	174	140	88	197	215	208	278	226	306	304	180	183	124	109	163	289	274
	%	%	7%	11%	13%	18%	13%	7%	6%	5%	6%	3%	7%	7%	10%	10%	8%	12%	11%	6%	7%	5%	4%	6%	11%	10%

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

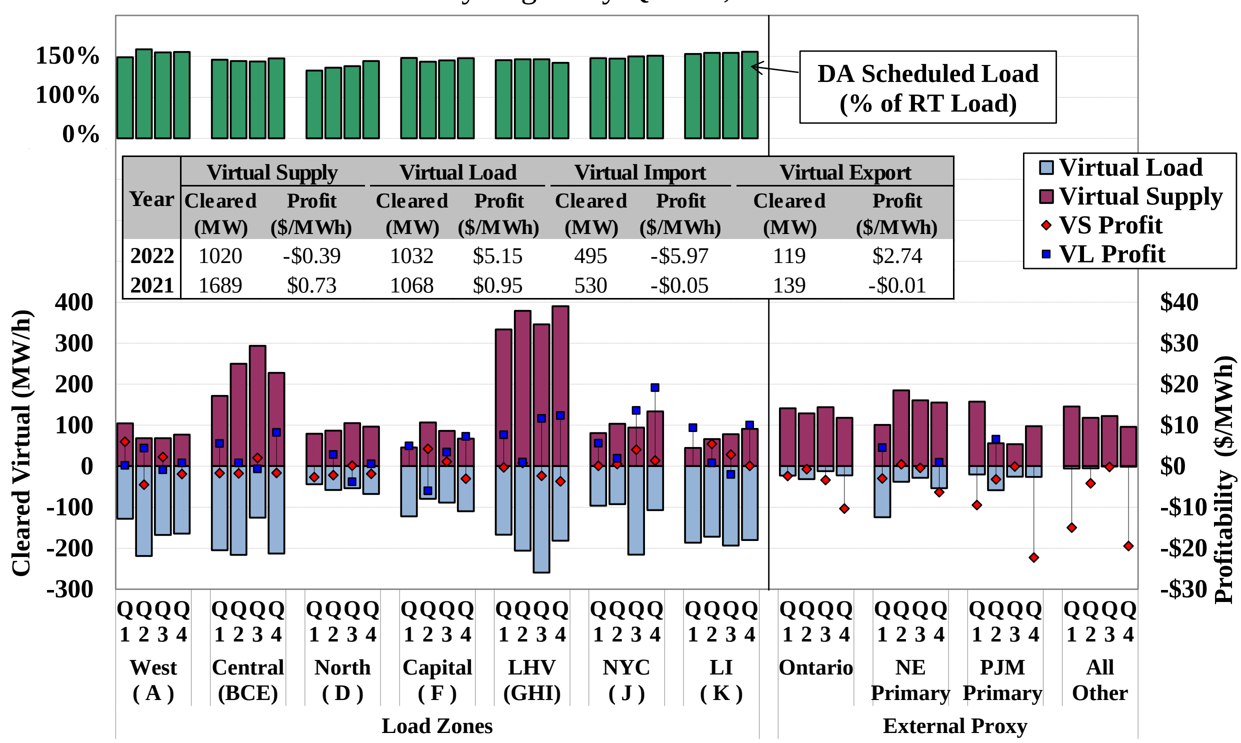
318 The calculation of the gross profitability for virtual imports and exports does not account for the profit (or loss) related to price differences between day-ahead and real-time in the neighboring markets.

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 2022. 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 2021 and 2022.

Figure A-53: Virtual Trading Activity[319]
by Region by Quarter, 2022



Year	Virtual Supply Cleared (MW)	Virtual Supply Profit ($/MWh)	Virtual Load Cleared (MW)	Virtual Load Profit ($/MWh)	Virtual Import Cleared (MW)	Virtual Import Profit ($/MWh)	Virtual Export Cleared (MW)	Virtual Export Profit ($/MWh)
2022	1020	-$0.39	1032	$5.15	495	-$5.97	119	$2.74
2021	1689	$0.73	1068	$0.95	530	-$0.05	139	-$0.01

319 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 is bottlenecked, limiting dispatch of the least expensive generators to satisfy system demand. When congestion occurs, the market software establishes clearing prices that vary by location to reflect the cost of meeting load at each location. These Location-Based Marginal Prices ("LBMPs") reflect that higher-cost generation is required at locations where transmission constraints prevent the free flow of power from lower-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 purchase bids and sell offers in merit order are not scheduled in order to reduce flows over constrained facilities. Congestion charges are applied to purchases and sales scheduled 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 Transmission Congestion Contracts ("TCCs"), which entitle the holder to payments corresponding to the congestion charges between and the source and sink locations. For example, if a participant holds 150 MW of TCCs 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 real-time bilateral transactions are based on the difference between the locational prices at the two locations of the bilateral contract in the real-time market. 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.

- Linear Constraints to Model Long Island East End TVR Requirements – Subsection E describes a modeling approach to more efficiently schedule and price resources to satisfy the Transient Voltage Recovery ("TVR") requirements on the East End of Long Island.

- Congestion Revenue Shortfalls – Subsections F and G analyze congestion 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

This subsection summarizes 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.[320]

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:

- *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.[321] To reduce flows in real time below the day-ahead schedule, the NYISO must redispatch generators by increasing generation downstream of the constraint and reducing generation upstream of the constraint. These redispatch costs (i.e., the difference between the payments for increased generation and the revenues from reduced generation in the two areas) are the balancing congestion shortfall that is recovered through uplift.

- *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

320 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).

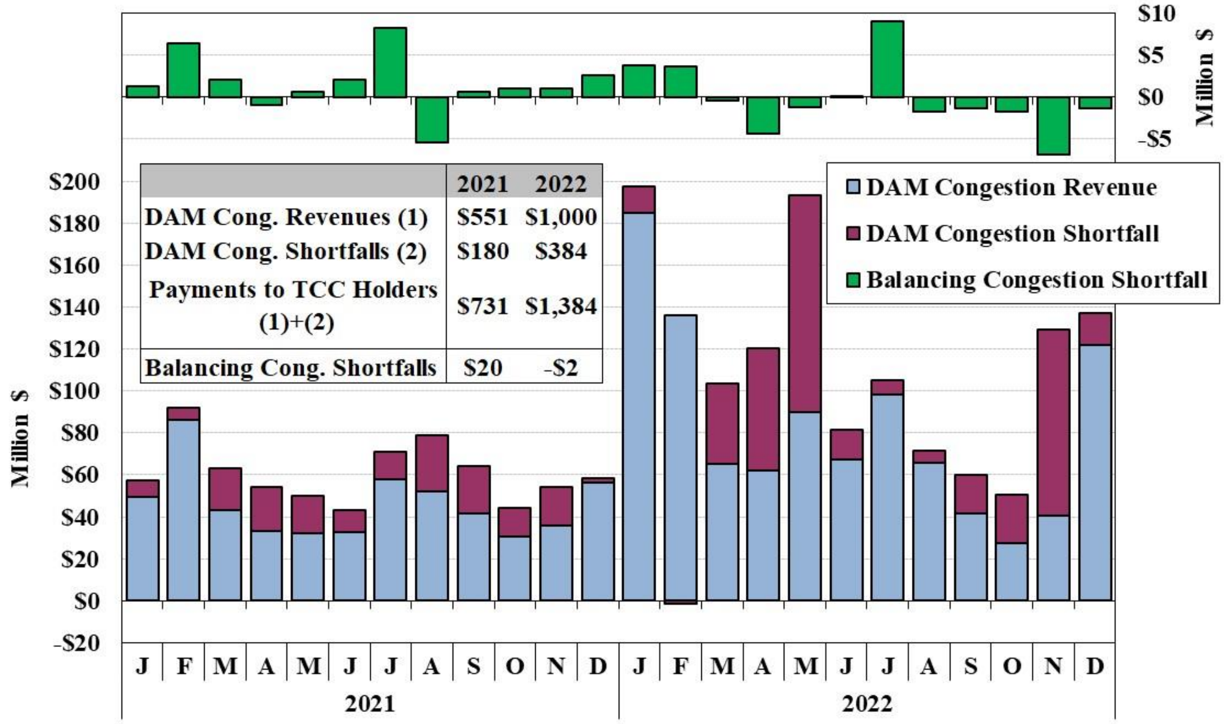
321 For example, suppose 100 MW is scheduled to flow across a particular line in the day-ahead market. If 90 MW flows across the line when it has a shadow price of $70/MWh in an hour in the real-time market, the NYISO will have a balancing congestion shortfall of $700 in that hour ((100 MW – 90 MW) *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

modeled in the day-ahead market when it is congested.[322] 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.

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 2021 and 2022. The upper portion of the figure shows balancing congestion shortfalls. The lower portion of the figure shows day-ahead congestion revenues collected by the NYISO and day-ahead congestion shortfalls and the sum of these two categories is equal to the total net payments to TCC holders in each month. The table in the figure reports these categories on an annual basis.

Figure A-54: Congestion Revenue Collections and Shortfalls
2021 - 2022



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

322 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).

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 system needs in real-time. Therefore, it is useful to evaluate the consistency of congestion patterns between 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 2021 and 2022 on an annual basis, while Figure A-56 and Figure A-57 show the quantities separately for each quarter of 2022. The figures measure congestion in two ways: [323]

- 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.[324]

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.

[323] Binding transmission constraints with a shadow cost lower than $0.1/MWh are not included in these figures.

[324] The shadow cost of a transmission constraint represents the marginal value to the system of one MW of transfer capability.

- North to Central: Primarily transmission facilities within and out of the North Zone.
- Central to East: Transmission facilities from Western and Central New York to Eastern New York, 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, the Cricket Valley-to-Pleasant Valley Line).
- 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

2021 – 2022

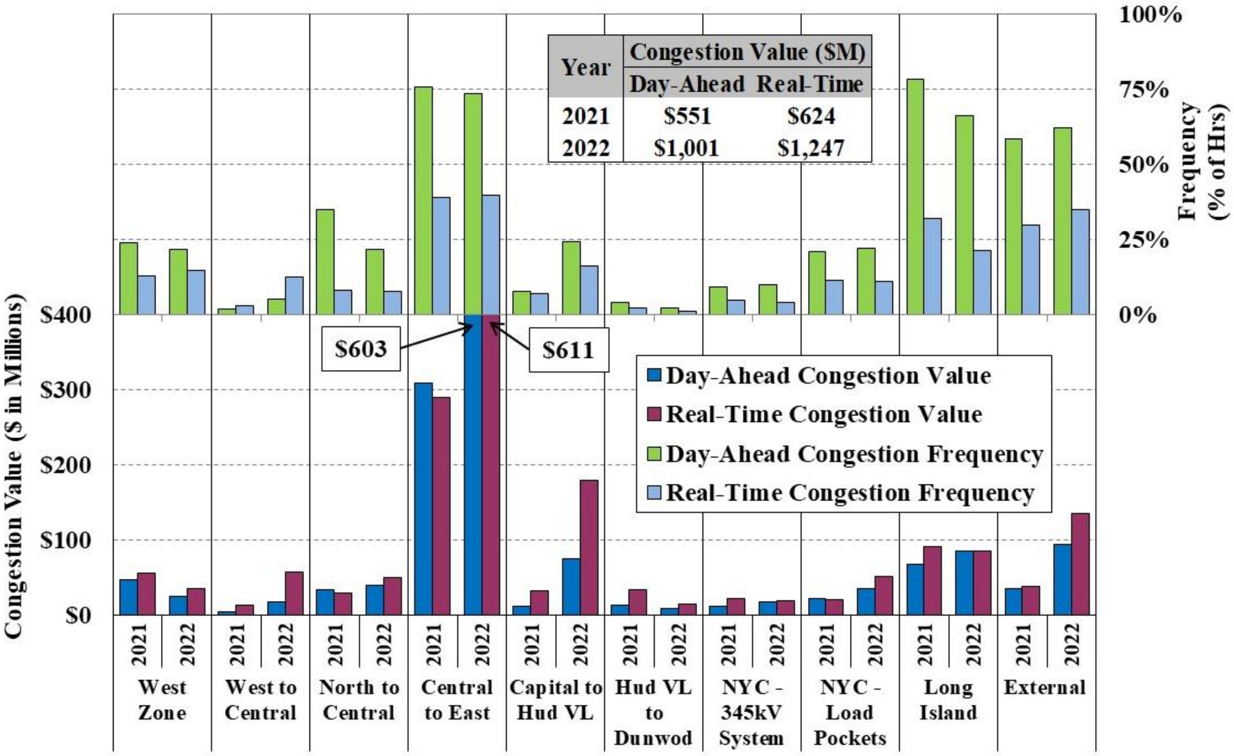


Figure A-56: Day-Ahead Congestion by Transmission Path
By Quarter, 2022

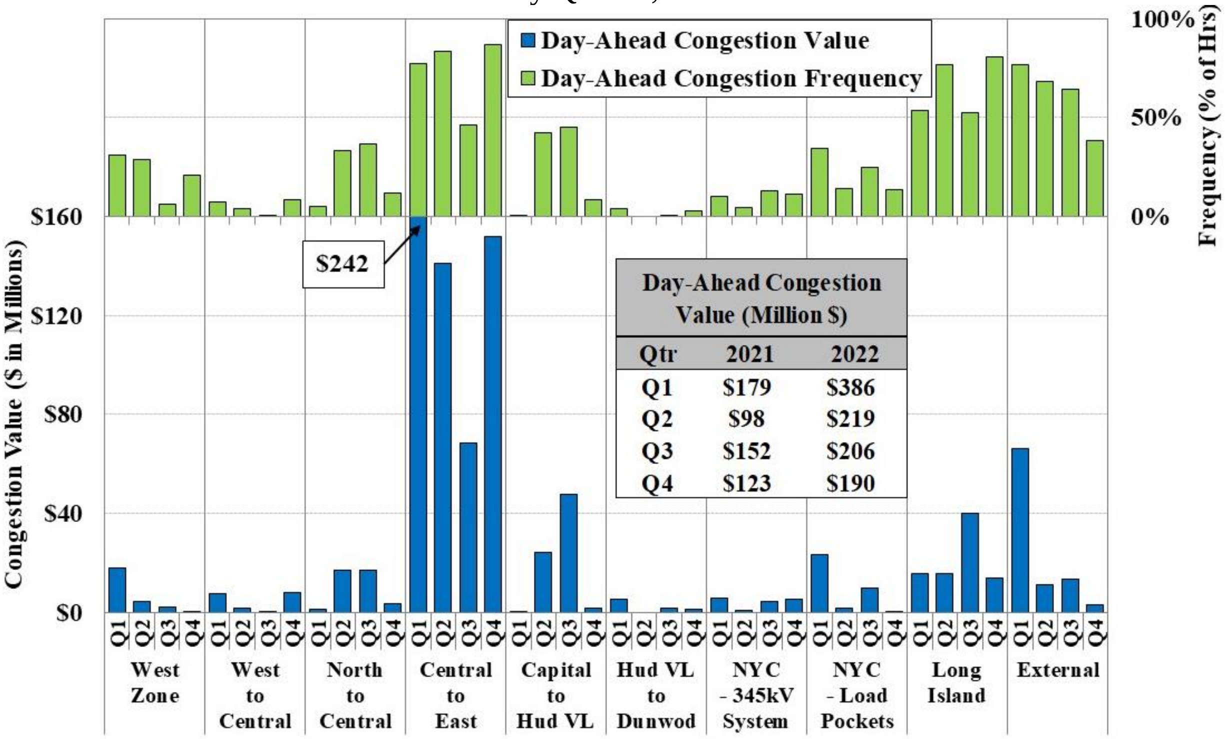
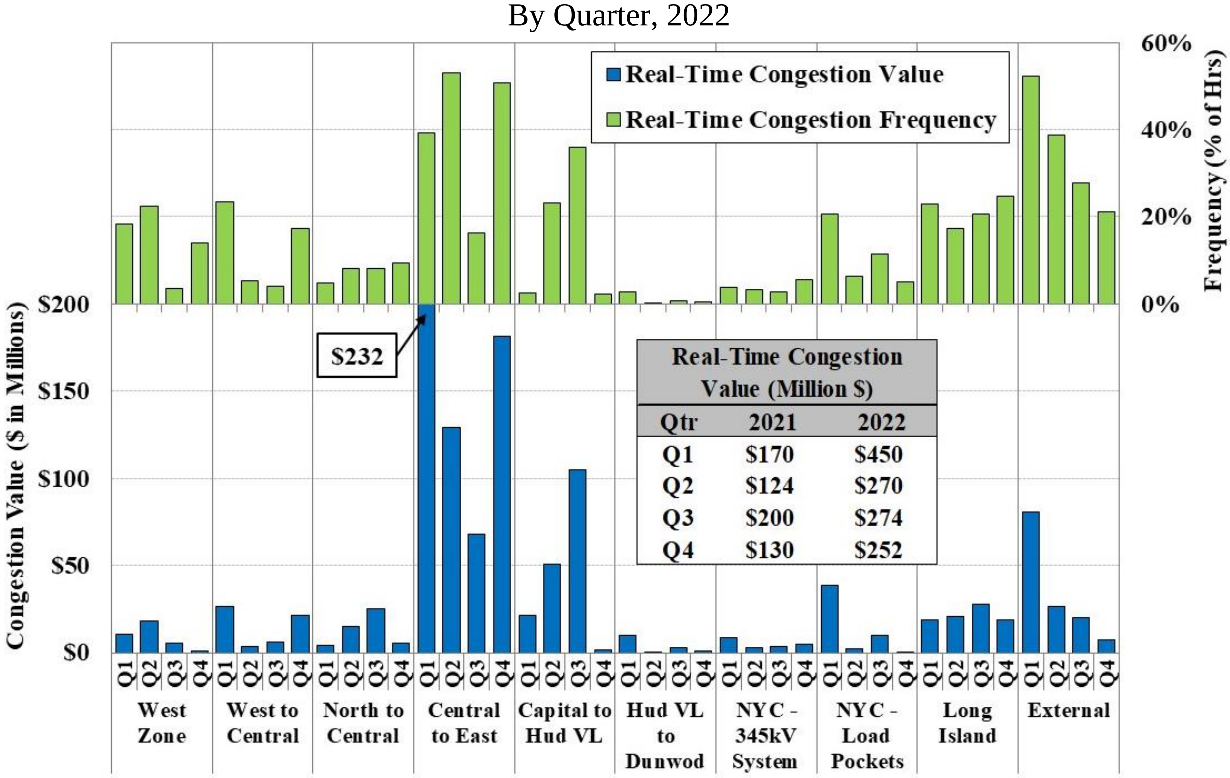


Figure A-57: Real-Time Congestion by Transmission Path
By Quarter, 2022



C. Real-Time Congestion Map by Generator Location

Figure A-58 to Figure A-59: Real-Time Load-Weighted Congestion Maps by Location

The previous subsection reports congestion patterns on a zonal basis or along large inter-zonal interfaces, while this subsection displays 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.

The maps display differences in LBMPs between generator nodes across the system,[325] 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 details of nodal congestion in the real-time market in 2022, specifically:

- Load-weighted hourly average real-time LBMP at each generator node within the region;
- For the systemwide map, real-time prices on the neighboring area's side of the external interface are load-weighted using NYCA systemwide load and presented as additional bubbles. These bubbles are not sized based on average generation levels;[326] and
- Pertinent gas market information including regional gas prices in the systemwide map and key operational points of gas delivery in the NYC map.[327]

The generator bubbles are sized based on annual average generation MWh, however the sizing of these bubbles differs between the two maps 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 is in proportion to 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.

325 Although the differences in LBMPs include the differences in congestion and losses, the differences in losses are usually much smaller than the differences in congestion, particularly between generator nodes that are within smaller subareas.

326 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.

327 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

2022

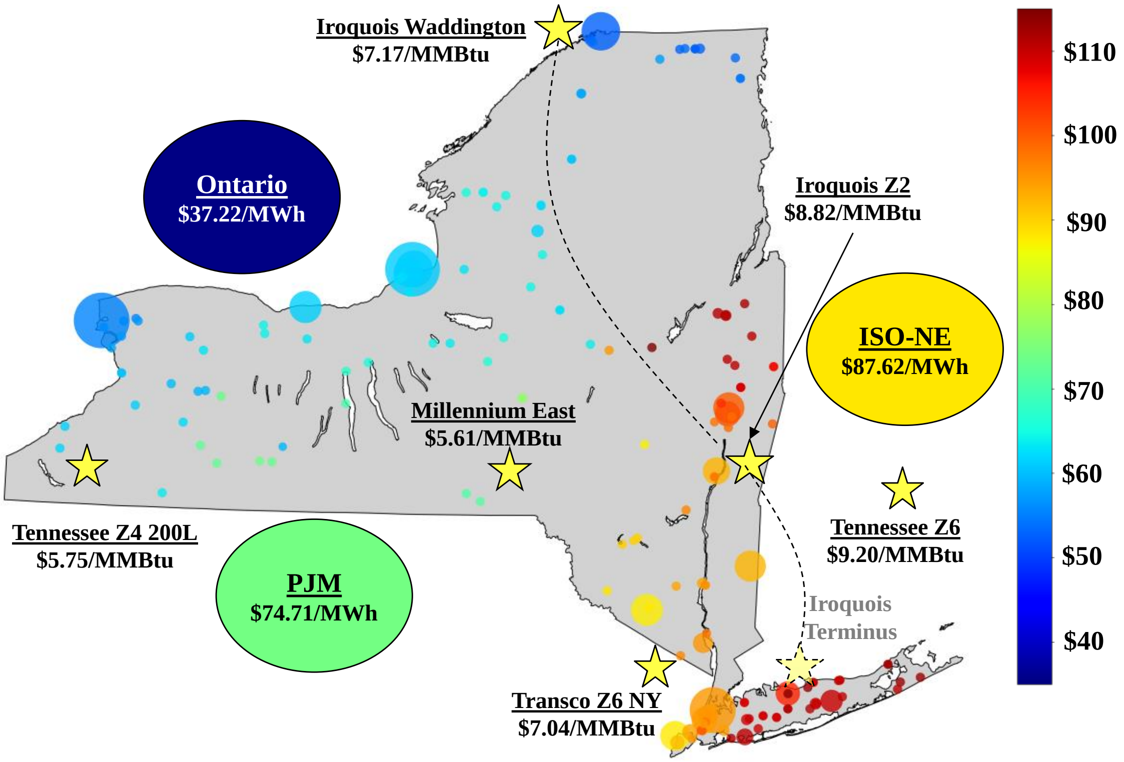
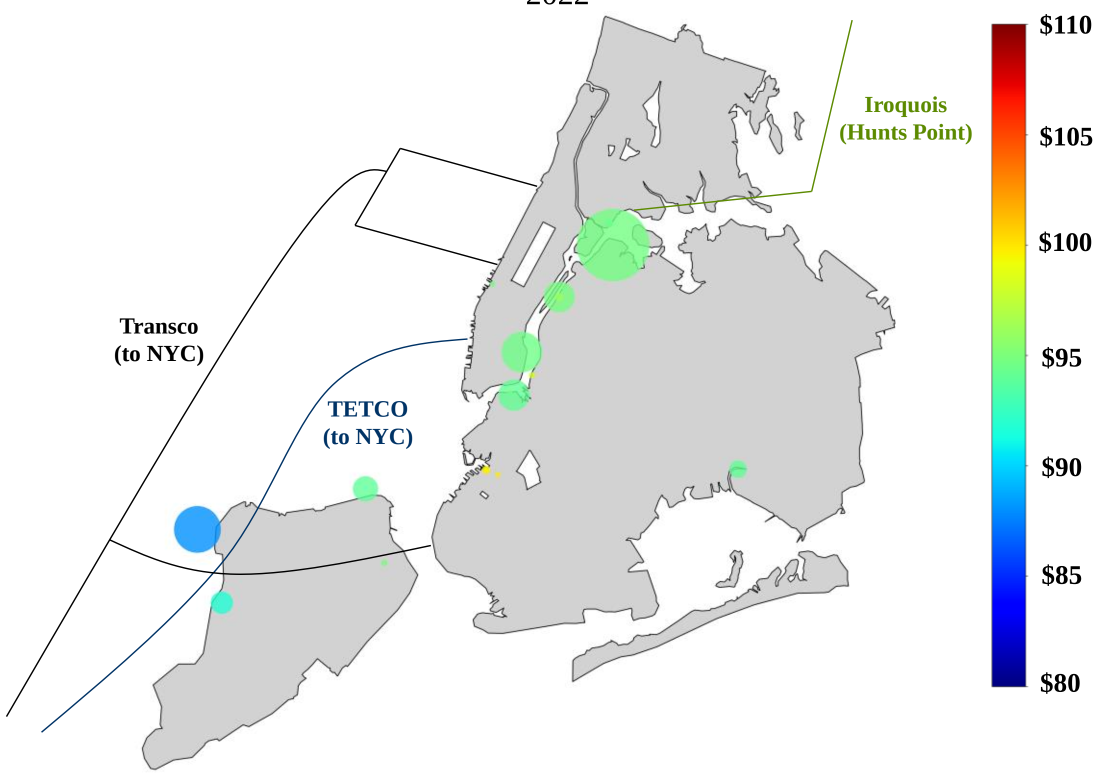


Figure A-59: NYC Real-Time Load-Weighted Generator Congestion Map

2022



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 2015 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:

- 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 high voltage network.[328]

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 2022 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. In addition, the figure also reports the number of days when out-of-merit commitments were made to satisfy voltage needs or N-1-1 reserve needs in several local load pockets.

[328] These constraints are sometimes managed with the use of line switching on the distribution system, but this is not included in our analysis here.

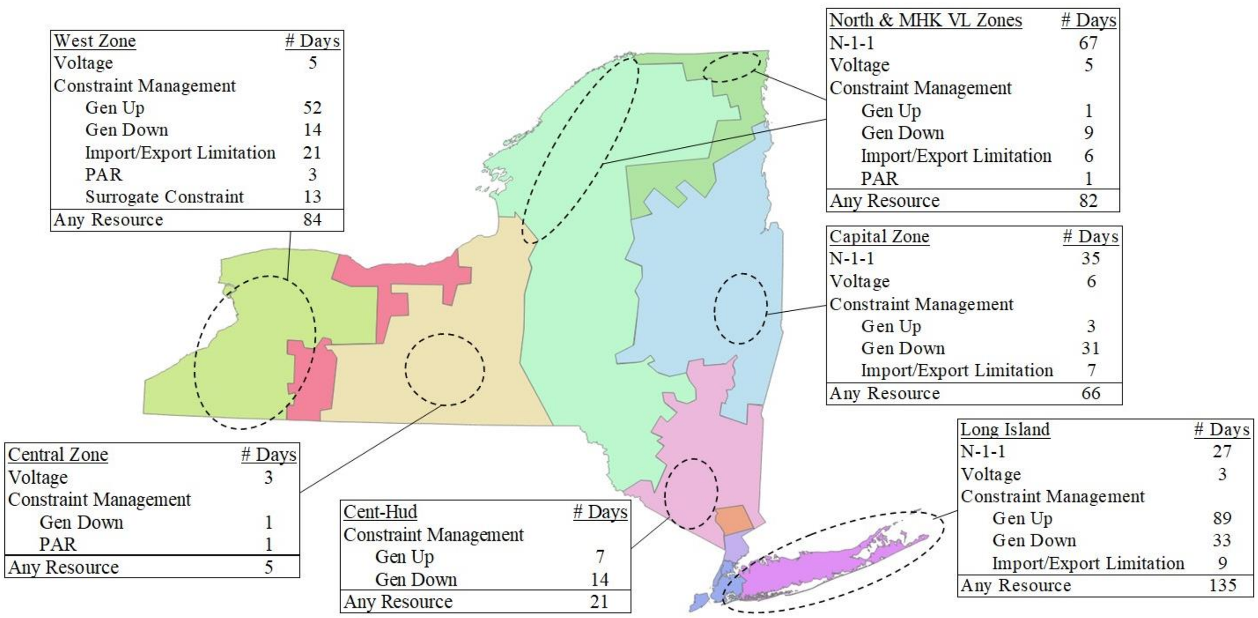
Figure A-61 focuses on the area of Long Island, showing the number of hours and days in 2022 when various resources were used to manage 69 kV (labeled as "69 kV OOM") and TVR constraints (labeled as "TVR OOM") in four load pockets of Long Island:

- Valley Stream: Mostly constraints around the Valley Stream bus;
- Brentwood: Mostly constraints around the Brentwood bus;
- East of Northport: Mostly the Central Islip-Hauppauge and the Elwood-Deposit circuits;
- East End: Mostly the constraints around the Riverhead bus and the TVR requirement.

For a comparison, the tables also show the frequency of congestion management on the 69 kV and 138 kV constraints 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.[329]

Figure A-60: Constraints on the Low Voltage Network in New York

Summary of Resources Used to Manage Constraint, 2022

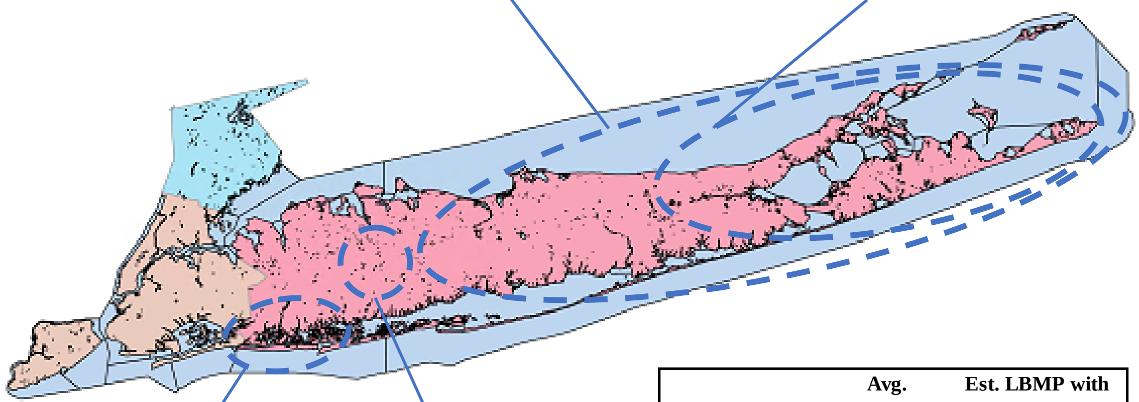


329 The following generator locations are chosen to represent each load pocket: (a) Barrett ST for the Valley Stream pocket; (b) NYPA Brentwood GT for the Brentwood pocket; (c) Holtsville IC for the East of Northport pocket; and (d) Green Port GT for the East End pocket.

Figure A-61: Constraints on the Low Voltage Network on Long Island
Frequency of Action Used to Manage Constraint, 2022

East of Northport	#Hours	#Days
69kV OOM	148	25
69kV	463	85
138kV	373	69
TOTAL	731	116

East End	#Hours	#Days
69kV OOM	84	7
TVR OOM	814	68
TOTAL	887	74



Valley Stream	#Hours	#Days
69kV OOM	604	65
138kV	834	132
TOTAL	1383	162

Brentwood	#Hours	#Days
69kV OOM	38	8
69kV	741	116
TOTAL	751	117

Load Pocket	Avg. LBMP	Est. LBMP with Local Constraints
Brentwood	$98.31	$98.34
East End	$99.40	$127.95
East of Northport	$97.30	$98.37
Valley Stream	$98.08	$99.50

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.[330] These required resources are expensive oil peakers, which are not often economically committed. Therefore, OOM commitments are made by the local TO based on operating guidelines.[331] 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 multiple 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 DRSS is out of service and local load arises to different levels. [332] 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.

330 Includes Global Greenport GT, East Hampton units, South Hampton IC, and Southhold IC.

331 See *East End Operating Guideline*, available at: https://oasis.psegliny.com/c.cfm/Transmission_Owner_Information_Being_Released_to_Market.

332 This table is excerpted directly from the *East End Operating Guideline*.

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 2022 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)

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 scenarios (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.[333] 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 >= Load – (115-1) (for D-VAR I/S)
- 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

333 The only exception is at the left bottom corner, where blue and yellow represent both 9 and 12.

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

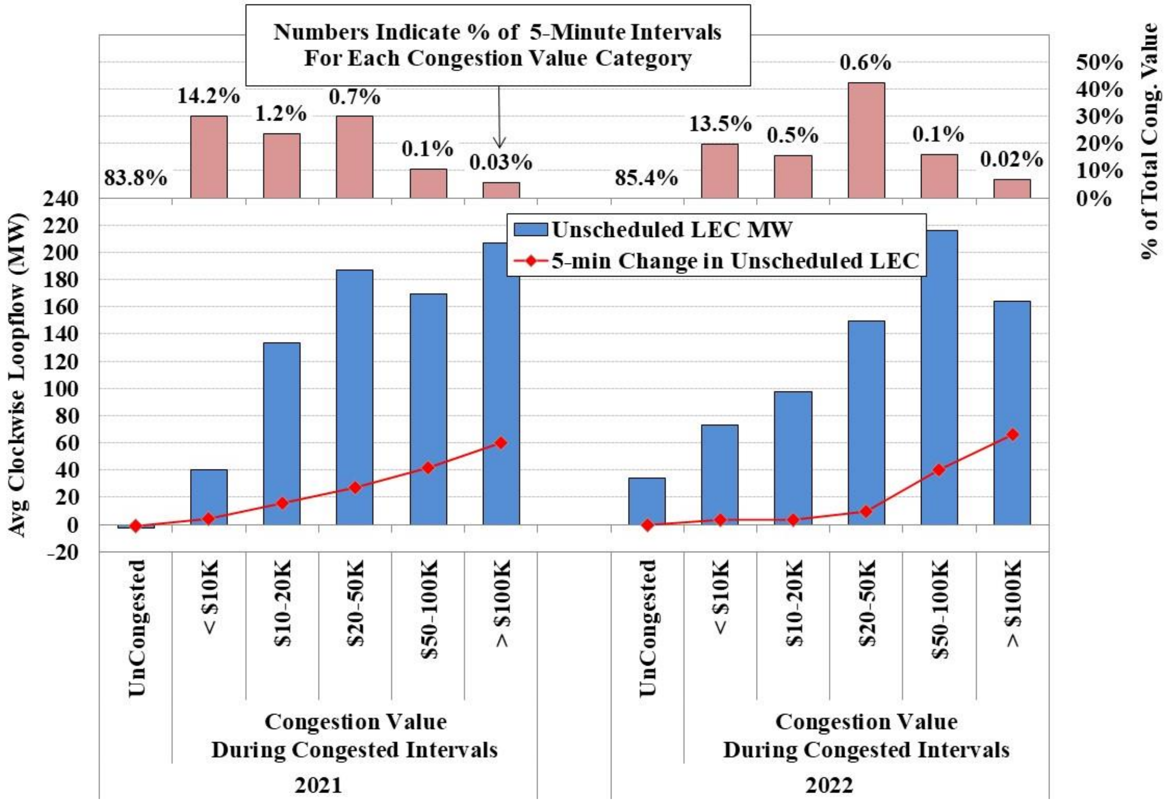
Unscheduled clockwise loop flows are primarily of concern in congested intervals, when they reduce the capacity available for scheduling internal generation to satisfy internal load and increase congestion on transmission paths in Western New York, particularly in the West Zone.

Figure A-62 illustrates how and to what extent unscheduled loop flows affected congestion on market-modeled West Zone constraints in 2021 and 2022. 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.[334] 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 2021 and in 2022, 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 between $50,000 and $100,000 during 0.1 percent of all intervals in 2022, which however accounted for 16 percent of total priced congestion value in the West Zone.

334 The congestion value for each constraint is calculated as (constraint flow × constraint shadow cost × interval duration). Then this is summed up for all binding constraints for the same interval. For example, if a 900 MW line binds with a $300 shadow price and a 700 MW line binds with a $100 shadow price in a single 5-minute interval, the resulting congestion value is $28,333 = (900MW × $300/MWh + 700MW × $100/MWh) * 0.083 hours.

Figure A-62: Clockwise Lake Erie Circulation and West Zone Congestion
2021 – 2022



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 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.

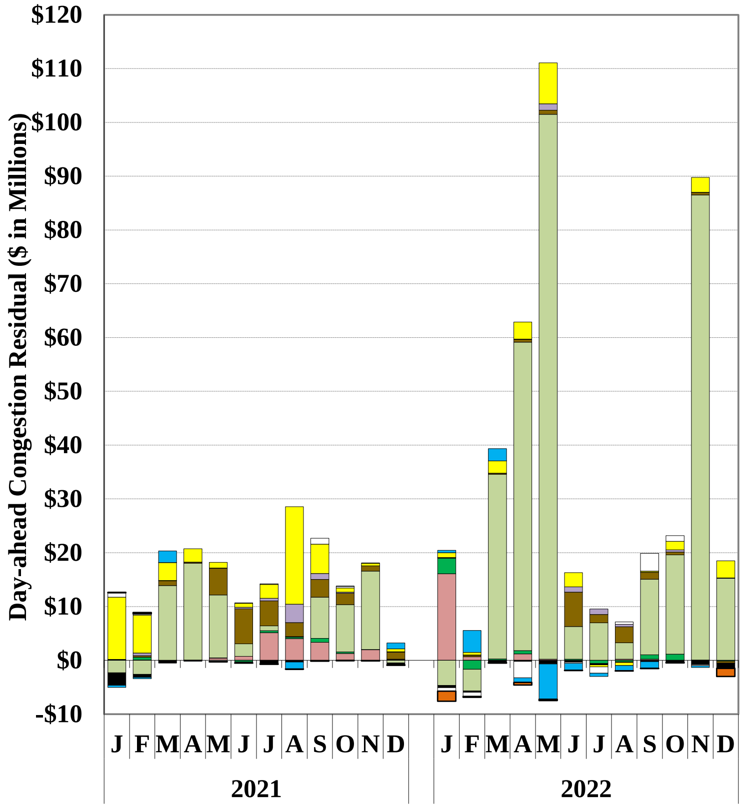
Figure A-63 shows day-ahead congestion shortfalls by transmission path or facility in each month of 2021 and 2022. Positive values indicate shortfalls, while negative values indicate surpluses. The shortfalls are shown for the following paths:

- West Zone Lines: Transmission lines in the West Zone.
- West to Central: Transmission lines in the Central Zone and transmission interfaces from West to Central (e.g., the West-Central Interface, the Dysinger Interface).
- 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.
- 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 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, labeled as “901/903 PARs” in the figure; and
  - Grandfathered TCCs (“GFTCC”) that exceed the transfer capability of the system from Dunwoodie (Zone I) to Long Island (Zone K), labeled as “Excess GFTCC Allocations” in the figure.

Figure A-63: Day-Ahead Congestion Shortfalls
2021 – 2022



Category	Annual Shortfall ($M) 2021	2022
Central to East	$72.5	$334.6
Long Island Lines		
901/903 PARs	-$4.9	-$4.7
Excess GFTCC Allocations	$6.1	$4.3
Other Factors	$54.2	$23.9
West Zone Lines	$17.0	$18.5
North to Central	$27.8	$14.7
New York City	$2.2	$3.2
West to Central	$0.1	-$4.5
External	$1.1	-$5.5
All Other Facilities	$2.4	-$1.3

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.

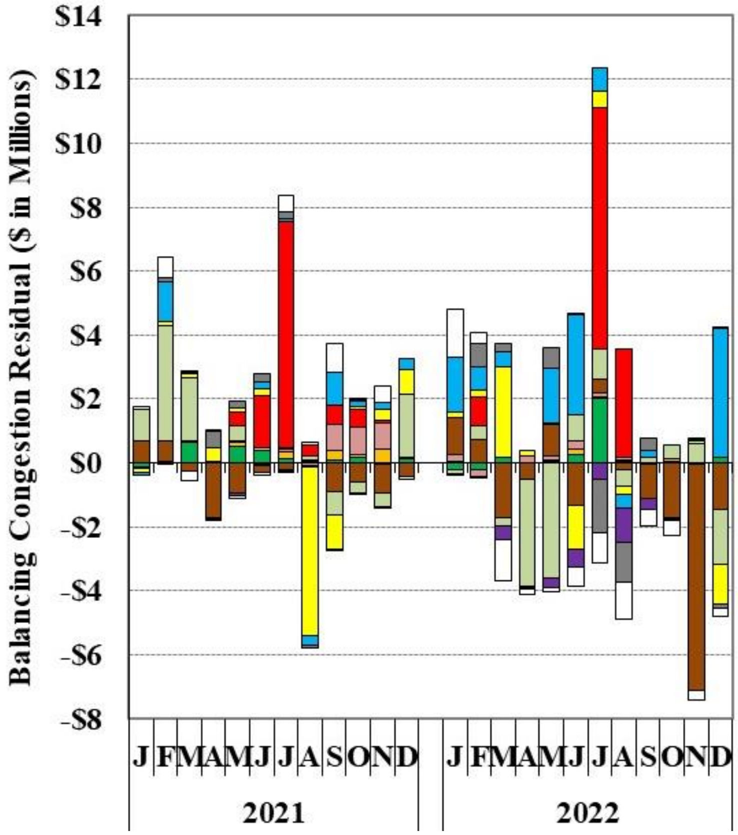
- Unscheduled loop flows – loop flows from other regions use a portion of the transmission capability across many interfaces in New York, reducing the portion of transmission capability available to the NYISO market in the direction of the loop flows. A balancing congestion revenue shortfall occurs when 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 2021 and 2022. 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[335]

2021 – 2022



Category	Annual Shortfall ($M) 2021	Annual Shortfall ($M) 2022
External	$2.9	$12.3
TSA Constraints	$10.8	$11.9
North to Central	$2.0	$2.4
West Zone Lines		
Ramapo, A & JK PARs	$1.2	$0.5
Other Factors	$2.6	$0.6
Long Island Lines	-$4.4	$1.0
Capital to Hud VL		
Ramapo, A & JK PARs	-$0.2	-$3.3
Other Factors	$1.3	-$0.9
Central to East		
Ramapo, A & JK PARs	-$4.8	-$11.7
Other Factors	$7.8	-$6.2
All Other Facilities	$2.2	-$4.0

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.

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335 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 2022.

We estimate ambient-adjusted ratings based on the following assumptions: [336]

- 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.[337] 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.[338] 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

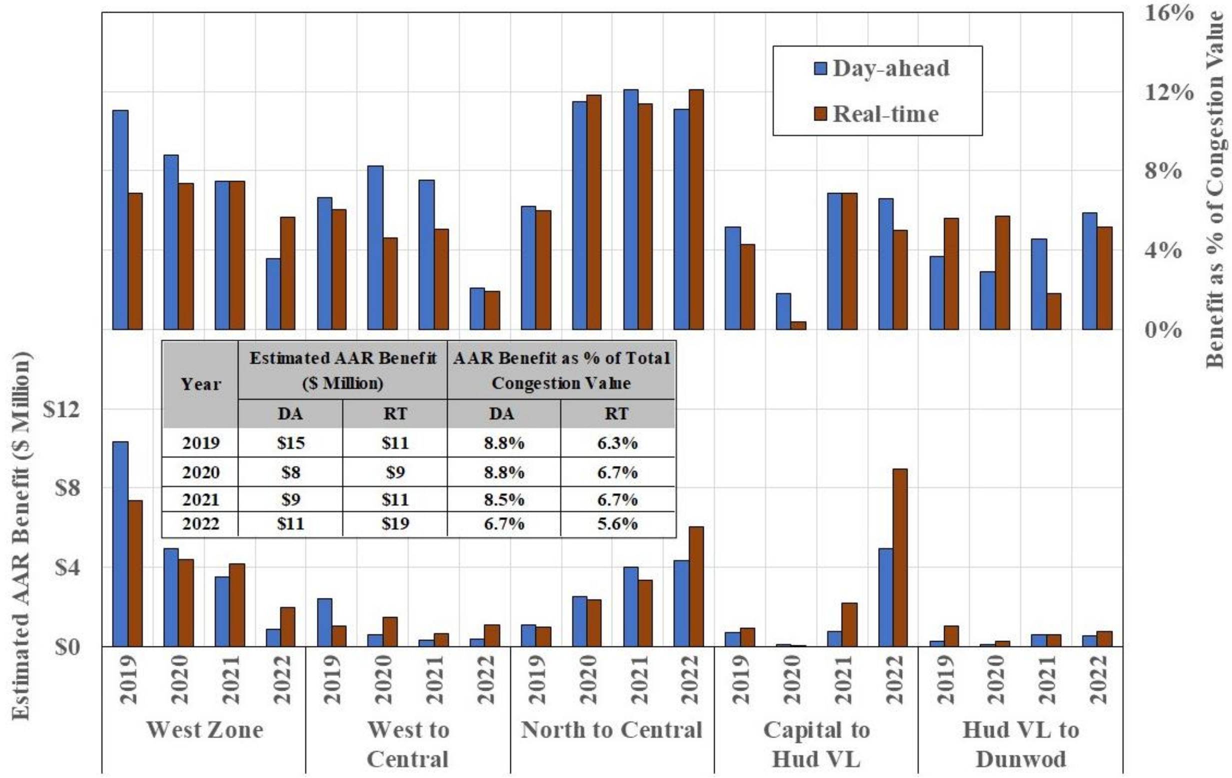
336 See "Tie-Line Ratings Task Force Final Report on Tie-Line Ratings" by New York Power Pool, 1995.

337 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.

338 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
2019-2022



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%
2022	$11	$19	6.7%	5.6%

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* [339] – 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 2021/22 and Summer 2022 Capability Periods (i.e., the 12-month period from November 2021 through October 2022). 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 2021/22 Capability Period; (c) four rounds of six-month auctions for the Summer 2022 Capability Period; and (d) twelve Balance-of-Period auctions for each month of the 12-month Capability Period.[340] 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.[341]

339 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.

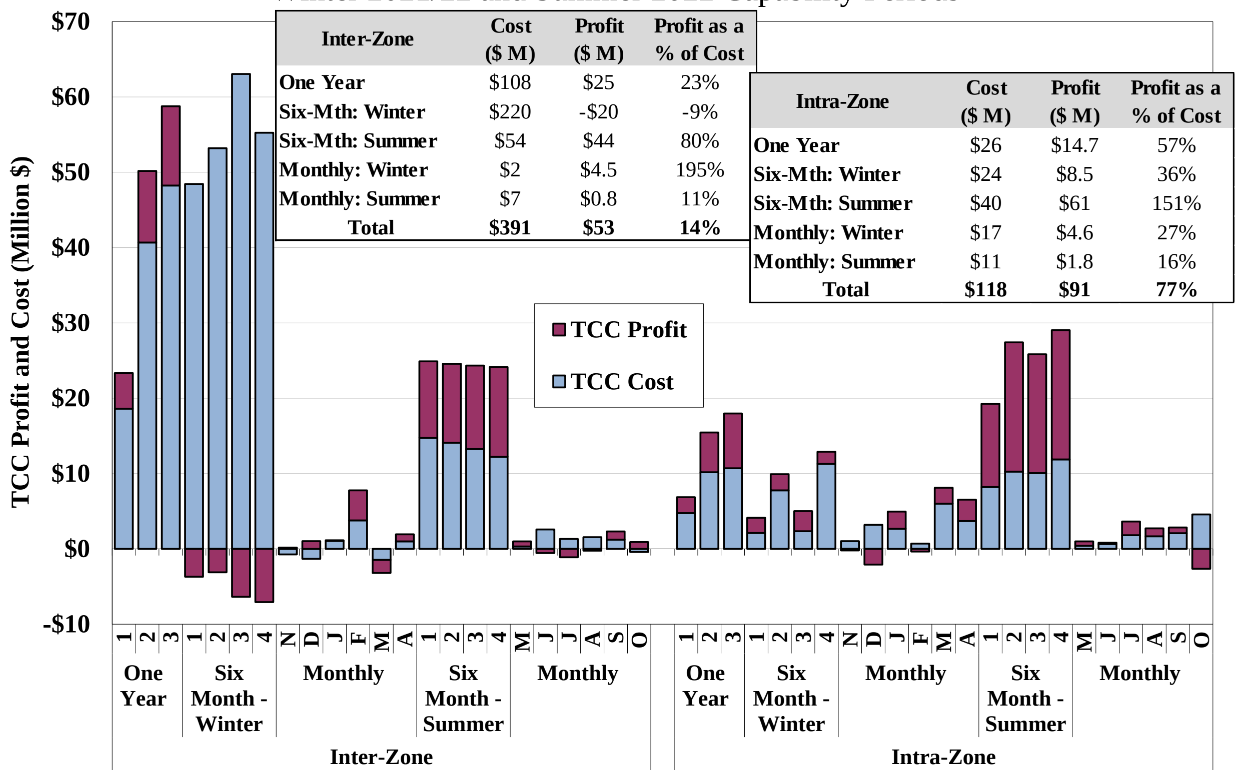
340 In the figure, the bars in the 'Monthly' category represent aggregated values for the same month from all applicable BOP auctions.

341 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 2021/22 and Summer 2022 Capability Periods



Inter-Zone	Cost ($ M)	Profit ($ M)	Profit as a % of Cost
One Year	$108	$25	23%
Six-Mth: Winter	$220	-$20	-9%
Six-Mth: Summer	$54	$44	80%
Monthly: Winter	$2	$4.5	195%
Monthly: Summer	$7	$0.8	11%
Total	**$391**	**$53**	**14%**

Intra-Zone	Cost ($ M)	Profit ($ M)	Profit as a % of Cost
One Year	$26	$14.7	57%
Six-Mth: Winter	$24	$8.5	36%
Six-Mth: Summer	$40	$61	151%
Monthly: Winter	$17	$4.6	27%
Monthly: Summer	$11	$1.8	16%
Total	**$118**	**$91**	**77%**

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 2021/22 and Summer 2022 Capability Periods (i.e., the 12-month period from November 2021 through October 2022). 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 2021/22 and Summer 2022 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	$21	-$22	-$6	-$1	-$1	$0	$11	$0	$0	$0	$0	$0	$0	$0	$0	$4
GENESE	$0	$1	$2	$1	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$3
CENTRL	$22	-$2	$42	-$1	-$15	$0	$109	$0	$0	$1	$0	$0	$0	$0	$2	$159
MHK VL	$5	$0	$2	-$42	-$3	$0	$2	$0	$0	$0	$0	$0	$0	$11	$0	-$26
NORTH	$0	$2	$13	$49	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$64
CAPITL	$0	$0	-$1	-$2	$0	$71	-$43	-$4	-$7	$0	$0	$0	$0	$0	$0	$13
HUD VL	-$1	$0	-$8	$0	$0	$24	-$2	$3	$5	$25	$0	$0	$0	$82	-$3	$124
MILLWD	$0	$0	$0	$0	$0	$0	-$1	$0	$0	$0	$0	$0	$0	$0	$0	-$2
DUNWOD	$0	$0	$0	$0	$0	$0	$0	$0	$0	$1	$0	$0	$0	$0	$0	$1
N.Y.C.	$0	$0	$0	$0	$0	$0	-$1	$0	-$1	$13	$0	$0	$0	$0	$0	$10
LONGIL	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$14	$0	$0	$0	$0	$12
O H	$3	$1	$0	$0	$0	$0	$4	$0	$0	$0	$0	$0	$0	$3	$0	$10
H Q	$0	$0	$0	$38	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$37
NPX	$0	$0	$0	$0	$0	$2	-$6	$0	$0	$0	$0	$0	$0	$0	$0	-$5
PJM	-$2	$0	-$11	$0	$0	$0	$106	$0	$0	$1	$0	$0	$0	$9	$0	$104
Total	**$48**	**-$20**	**$31**	**$41**	**-$19**	**$98**	**$178**	**-$2**	**-$4**	**$41**	**$14**	**$0**	**$0**	**$104**	**-$1**	**$509**

Table A-6: TCC Profit by Path
Winter 2021/22 and Summer 2022 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	$1	$4	$2	$0	$0	$0	$4	$0	$0	$0	$0	$0	$0	$0	$0	$12
GENESE	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	-$1	$0	$0	$0	-$1
CENTRL	-$5	$0	$4	$5	-$12	$0	$41	$0	$0	$0	$0	$0	$0	$0	$2	$35
MHK VL	-$2	$0	-$1	-$12	$0	$0	$1	$0	$0	$0	$0	$0	$0	$4	$0	-$11
NORTH	$0	$2	$6	$20	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$28
CAPITL	$0	$0	$0	-$1	$0	$50	-$12	-$3	-$13	$0	$0	$0	$0	-$6	$0	$16
HUD VL	-$1	$0	-$10	$0	$0	$6	$28	-$1	$0	-$12	$0	$0	$0	-$33	$0	-$22
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	$10	$0	$0	$0	$0	$0	$11
LONGIL	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$10	$0	$0	$0	$0	$10
O H	$1	$1	$0	$0	$0	$0	$1	$0	$0	$0	$0	$0	$0	-$1	$0	$2
H Q	$0	$0	$0	$24	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$24
NPX	$0	$0	$0	$0	$0	$0	$5	$0	$0	$0	$0	$0	$0	$0	$0	$5
PJM	$1	$0	$2	$0	$0	$0	$32	$0	$0	$0	$0	$0	$0	-$1	$0	$34
Total	**-$6**	**$8**	**$5**	**$38**	**-$13**	**$57**	**$100**	**-$4**	**-$12**	**-$3**	**$10**	**-$2**	**$0**	**-$36**	**$2**	**$144**

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 =

$$\sum_{l=901,903}\left([DAM\ MW_l - TCC\ MW_l] \times \sum_{c=constraint}\left[-DAM\ SF_{l,c} \times DAM\ SP_c\right]\right)$$

RTM Payment =

$$\sum_{l=901,903}\left([RTM\ MW_l - DAM\ MW_l] \times \sum_{c=constraint}\left[-RTM\ SF_{l,c} \times RTM\ SP_c\right]\right)$$

Total Payment = DAM Payment + RTM Payment, where a negative payment would result in a charge to ConEd. To illustrate, suppose there is congestion in the DAM on the interface from upstate to Long Island (Y50 Line), from upstate to NYC (Dunwoodie), and into the Valley Stream load pocket (262 Line) while the 901 Line flows are reduced below the contract amount:

- TCC MW_{901} = 96 MW
- DAM MW_{901} = 60 MW
- DAM SP_{Y50} = \$10/MWh
- DAM $SP_{Dunwoodie}$ = \$5/MWh
- DAM SP_{262} = \$15/MWh
- DAM $SF_{901, Y50}$ = 100%
- DAM $SF_{901, Dunwoodie}$ = -100%
- DAM $SF_{901, 262}$ = 100%
- DAM $Payment_{901}$ = \$720 per hour = (60 MW – 96 MW) x {(-100% x \$10/MWh) + (100% x \$5/MWh) + (-100% x \$15/MWh)}

Since DAM payments are made for deviations from the TCC modeling assumptions, the new financial transmission right would not alter the TCCs possessed by any market party.

Revenue Adequacy

Just as the LBMP compensation to generators is generally revenue adequate, the new financial transmission right would also be revenue adequate. This is illustrated by the following scenarios:

- Basecase Scenario – Provides an example of the current market rules where the NYISO receives revenues from loads that exceed payments to generators, thereby contributing to DAM congestion revenues.

- PAR Relief Scenario – Shows how a PAR-controlled line could be used to reduce congestion, allowing the owner of the line to be compensated without increasing uplift from DAMCRs.

- PAR Loading Scenario – Shows how the owner of the line would be charged if the DAM schedule increased congestion relative to the TCC schedule assumption.

These scenarios use a simplified four node network, including: Upstate, NYC, Valley Stream, and Rest of Long Island. The four nodes are interconnected by four interfaces:

- The Dunwoodie interface from Upstate to NYC,

- The Y50 Line from Upstate to Rest of Long Island,

- The 262 Line from Rest of Long Island to Valley Stream, and

- The PAR-controlled 901 Line from Valley Stream to NYC.

For simplicity, the 901 Line contract amount that is used in the TCC auction is rounded to 100 MW.

The Base Case Scenario shows that a net of $22,500 of DAM congestion revenue is collected from scheduling by generators and loads. The table also shows the amount of DAM congestion revenue that accrues on each constrained facility. In this example, DAMCR equals $0 because the flows on each constrained facility are equal to the capability/assumption in the TCC model. Since the 901 Line contract moves power from a high LBMP area to a low LBMP area, it reduces congestion revenue by $2,000, but it does not cause DAMCR because it is consistent with the TCC auction.

The PAR Relief Scenario shows that if the 901 Line flow is reduced from 100 MW to 10 MW, it reduces the generation needed in Valley Stream and increases generation in NYC, reducing overall production costs by $1,800 as compared to the Basecase Scenario. Since LBMPs do not change in this example, payments by loads are unchanged and $1,800 of additional congestion revenues are collected. The collection of additional congestion revenues allows the NYISO to compensate ConEd $1,800 for the PAR adjustment, and DAMCR remains at $0.

The PAR Relief Scenario shows that if the 901 Line flow is increased from 100 MW to 120 MW, it increases the generation needed in Valley Stream and reduces generation in NYC, increasing overall production costs by $400 as compared to the Basecase Scenario. Since LBMPs do not change in this example, payments by loads are unchanged and $400 less congestion revenue is collected. The collection of less congestion revenue requires the NYISO to charge ConEd $400 for exceeding the contract amount, and DAMCR remains at $0.

BASECASE SCENARIO

	Node	LBMP	Load	Generation	Load Revenue	Generator Payments
Gen/Load Payments	Upstate	$25	10000	13000	$250,000	$325,000
	NYC	$30	4000	1900	$120,000	$57,000
	Valley Stream	$50	350	150	$17,500	$7,500
	Rest of Long Is.	$35	2500	1800	$87,500	$63,000
	Total		16850	16850	$475,000	$452,500
	Net (Gen minus Load)			0		$22,500

	Interface	Shadow Price	Interface Flow	Congestion Revenue
Transmission Revenue	Dunwoodie	$5	2000	$10,000
	Y50	$10	1000	$10,000
	262 Line	$15	300	$4,500
	901 Line Contract	-$20	100	-$2,000
	Total			$22,500
	DAMCR (Gen minus Load minus Congestion)			$0

PAR RELIEF SCENARIO (901 Line Flow Reduced from 100 MW to 10 MW)

	Node	LBMP	Load	Generation	Load Revenue	Generator Payments
Gen/Load Payments	Upstate	$25	10000	13000	$250,000	$325,000
	NYC	$30	4000	1990	$120,000	$59,700
	Valley Stream	$50	350	60	$17,500	$3,000
	Rest of Long Is.	$35	2500	1800	$87,500	$63,000
	Total		16850	16850	$475,000	$450,700
	Net (Gen minus Load)			0		$24,300

	Interface	Shadow Price	Interface Flow	Congestion Revenue
Transmission Revenue	Dunwoodie	$5	2000	$10,000
	Y50	$10	1000	$10,000
	262 Line	$15	300	$4,500
	901 Line Contract	-$20	100	-$2,000
	901 Line Adjust	-$20	-90	$1,800
	Total			$24,300
	DAMCR (Gen minus Load minus Congestion)			$0

PAR LOADING SCENARIO (901 Line Flow Increased from 100 MW to 120 MW)

	Node	LBMP	Load	Generation	Load Revenue	Generator Payments
Gen/Load	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.[342,343] 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 aspects of transaction scheduling between New York and adjacent control areas:

- Subsection A summarizes scheduling patterns between New York and adjacent control areas;
- Subsection B evaluates convergence of prices between New York and neighboring control areas;
- Subsection C examines the efficiency of Coordinated Transaction Scheduling (“CTS”), including an evaluation of transaction offer patterns and profitability; and
- Subsection D provides a systematic 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.

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342 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.

343 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.

- Subsection E examines several key factors that lead to inconsistencies between RTC and RTD in more details.

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 2021 and 2022. 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
2021 – 2022

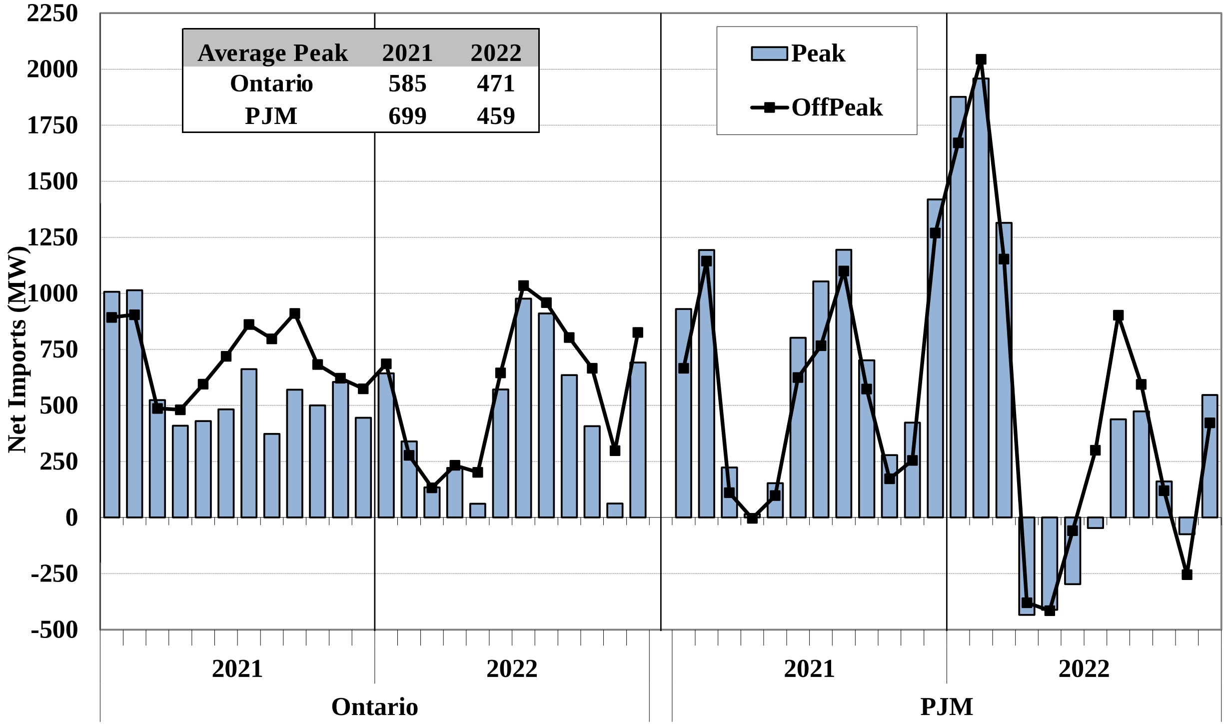


Figure A-68: Monthly Average Net Imports from Quebec and New England
2021 – 2022

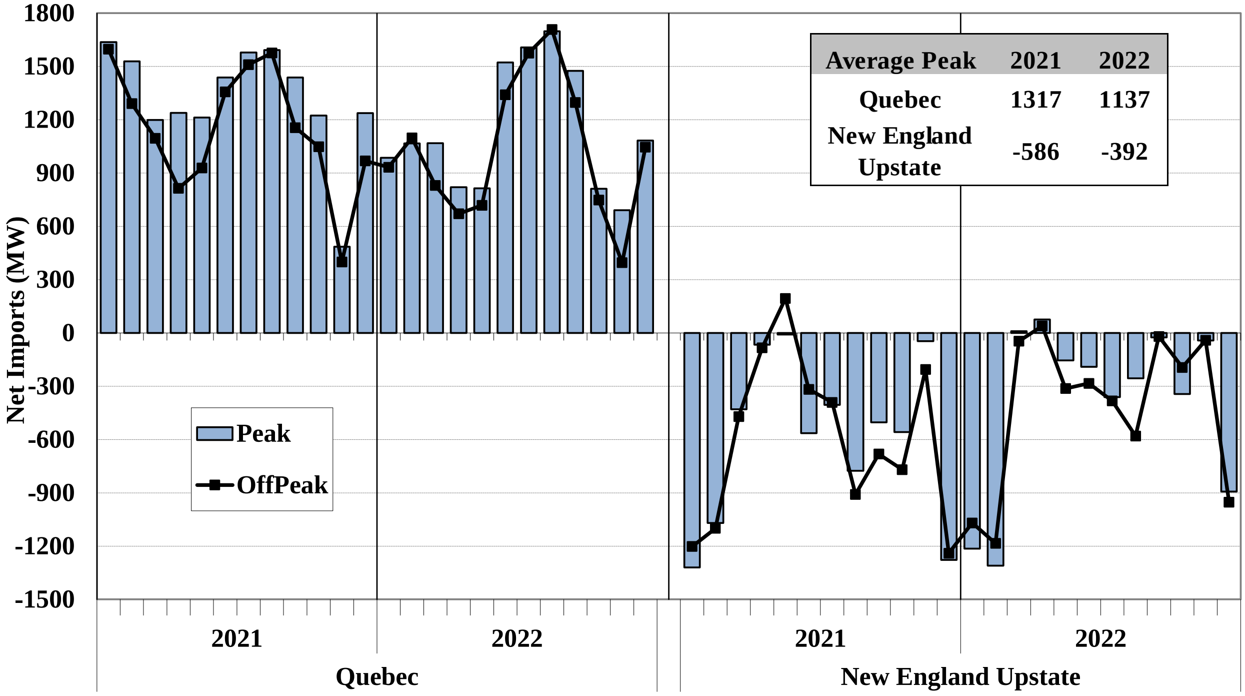


Figure A-69: Monthly Average Net Imports into New York City
2021 – 2022

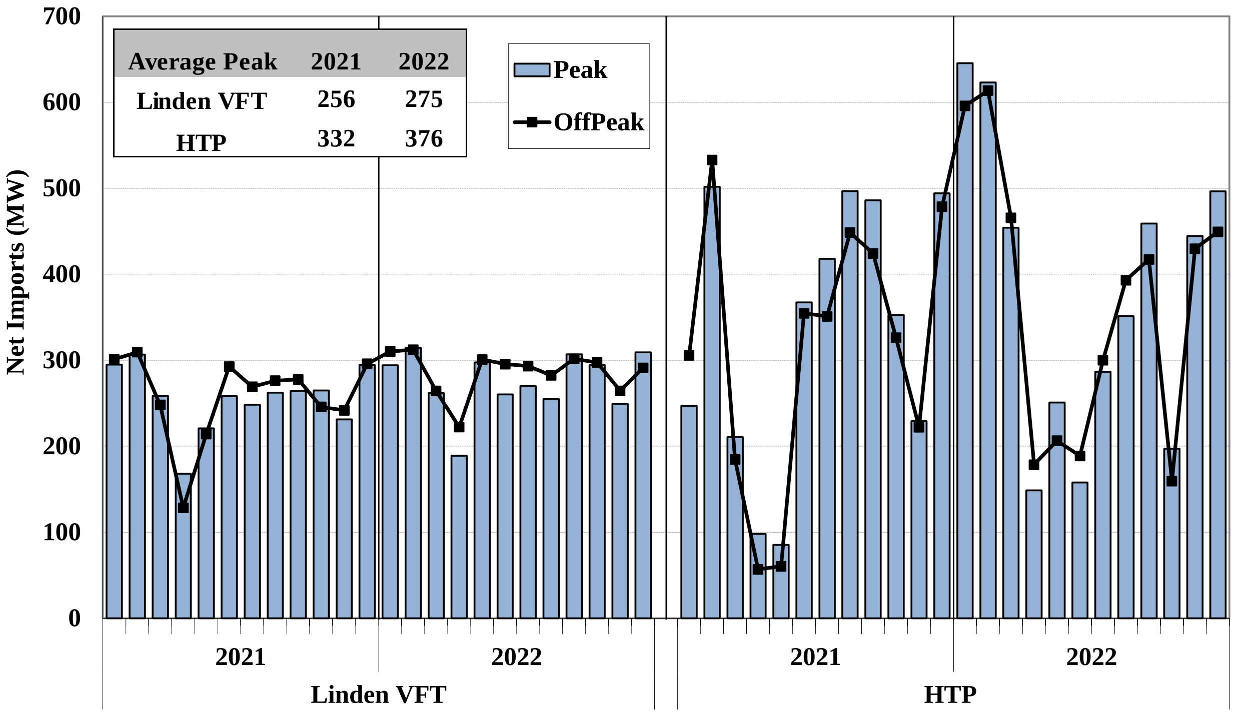
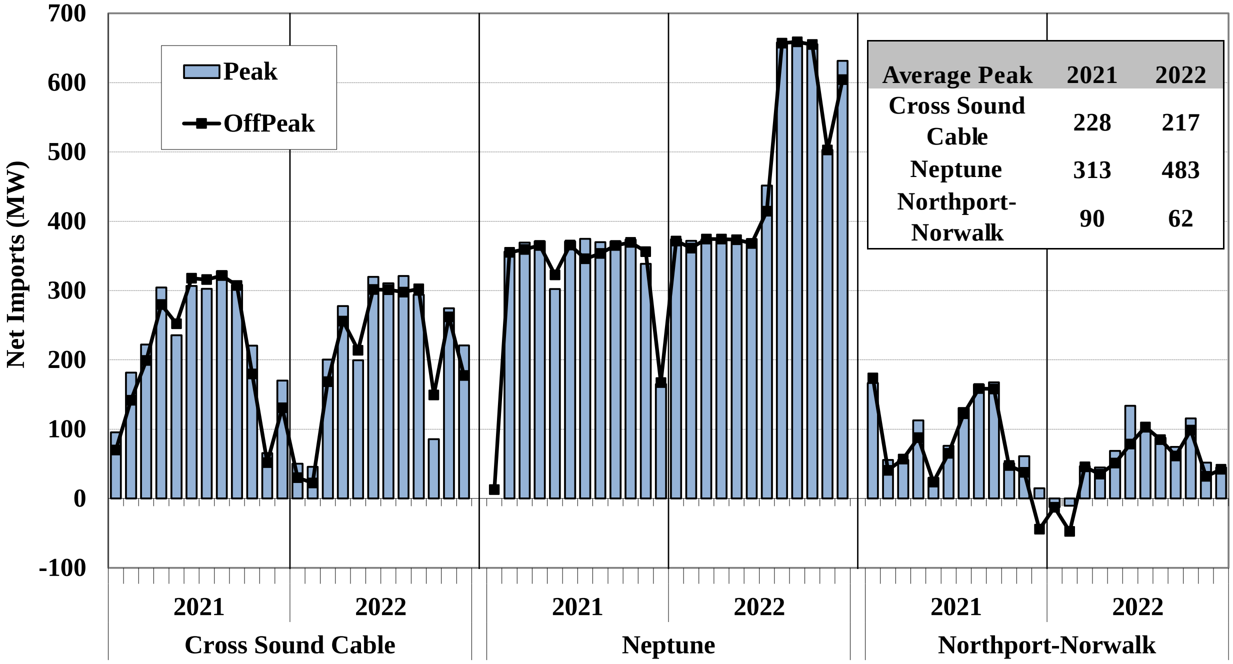


Figure A-70: Monthly Average Net Imports into Long Island
2021 – 2022



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.

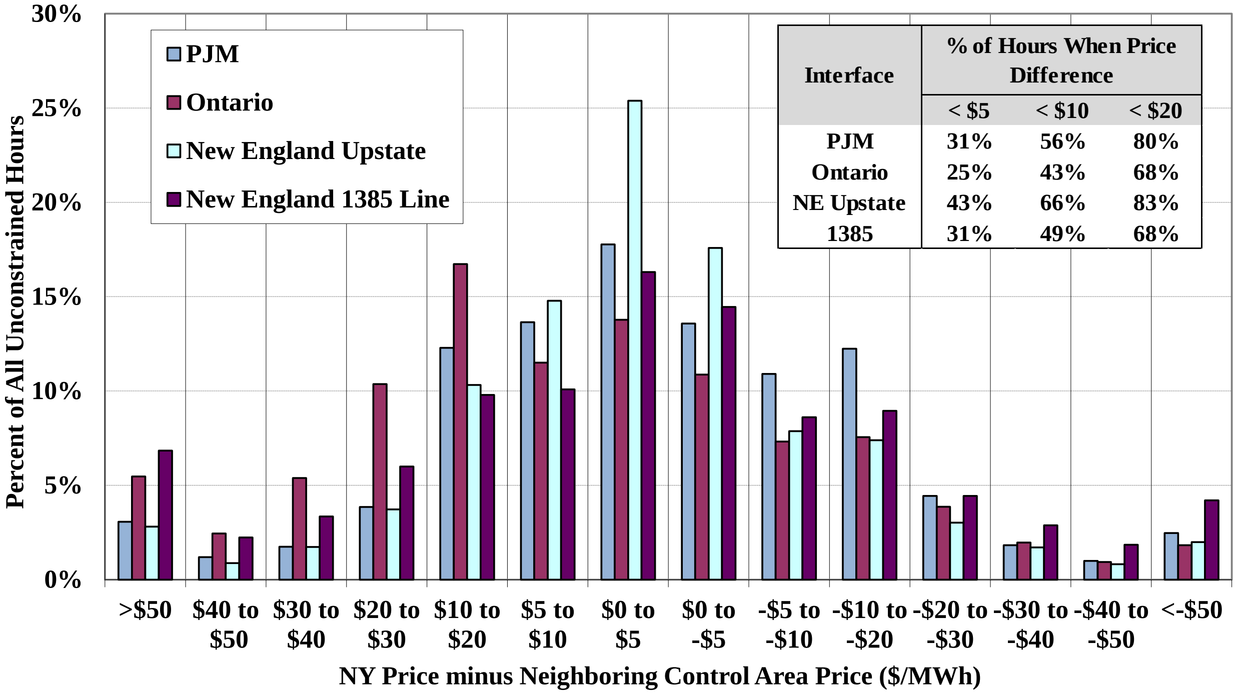
- The risks associated with curtailment and congestion reduce participants' incentives to schedule external transactions when expected price differences are small.

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 2022. 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.[344] 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, 2022



Interface	% of Hours When Price Difference		
	< $5	< $10	< $20
PJM	31%	56%	80%
Ontario	25%	43%	68%
NE Upstate	43%	66%	83%
1385	31%	49%	68%

344 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 2022. 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.[345]
- 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. [346]
- 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.[347]

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

345 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.

346 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.

347 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 – 2022

	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	-429	$4.63	42%	-$21.3	29	$4.00	59%	$9
Ontario	513	$9.75	73%	$64	9	$10.15	52%	$1.5
PJM	442	$1.21	74%	$67	35	-$1.57	66%	$49
Controllable Ties								
1385 Line	66	$3.58	70%	$5	-10	$4.48	57%	$3.6
Cross Sound Cable	214	$11.23	81%	$28	-1	$12.26	53%	-$0.4
Neptune	484	$27.99	97%	$108	-3	$25.86	29%	-$0.1
HTP	358	$14.46	91%	$62	12	$12.12	61%	$2
Linden VFT	256	$16.04	91%	$40	25	$11.43	75%	$4

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 2022. 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

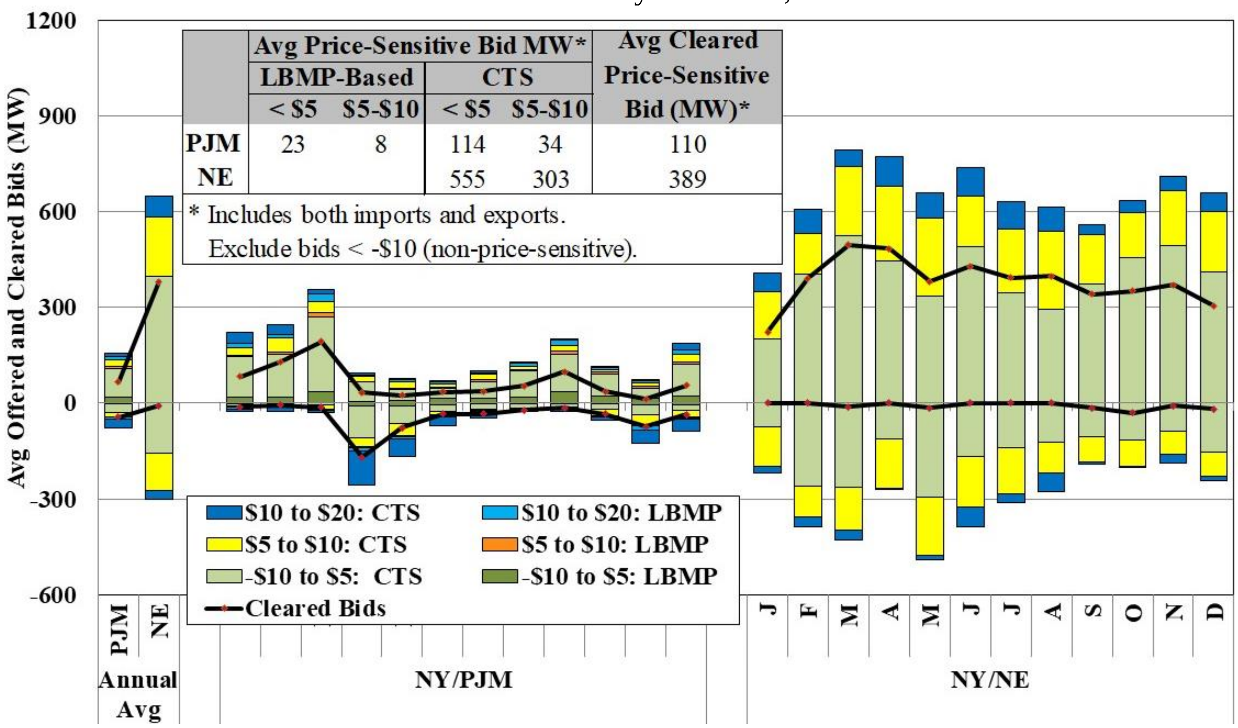
$10/MWh; and (c) between $10 and $20/MWh.[348] Bids that are offered below -$10/MWh or above $20/MWh are considered price insensitive for this analysis.

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 2022.

Figure A-72: Price-Sensitive Real-Time Transaction Bids and Offers by Month
PJM and NE Primary Interfaces, 2022



348 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 2022. 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 2022 and the inset table summarizes the annual average profit.

Figure A-73: Profitability of Scheduled External Transactions
PJM and NE Primary Interfaces, 2022

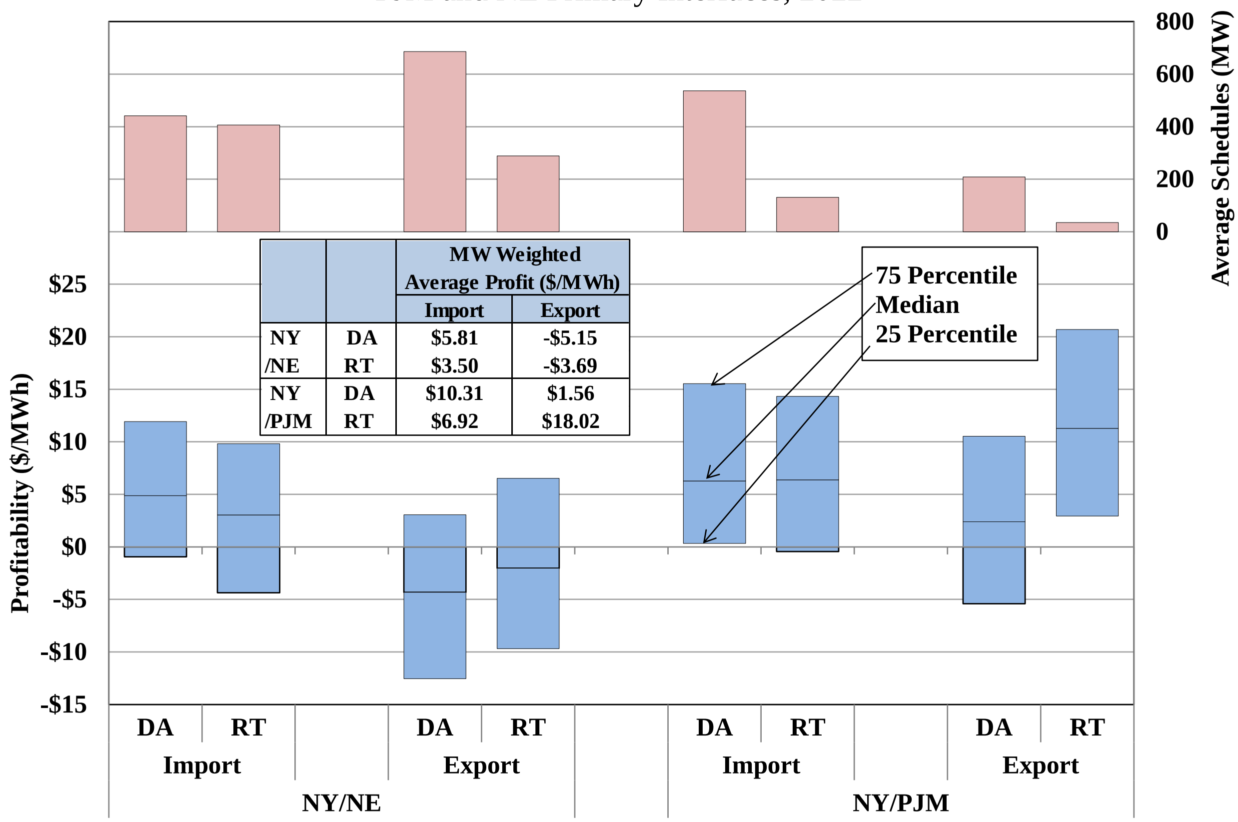


Table A-8: Efficiency of Intra-Hour Scheduling Under CTS

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. [349]

Table A-8 examines the performance of the intra-hour scheduling process under CTS at the primary PJM and New England interfaces in 2022. The table shows the following quantities:

- % of All Intervals with Adjustment– This shows the percent of quarter-hour intervals during which the interface flows were adjusted by CTS (relative to the estimated hourly schedule) in the scheduling RTC interval.
- Average Flow Adjustment – This measures the difference between the estimated hourly schedule and the final schedule. Positive numbers indicate flow adjustments in the import direction (i.e., from PJM or New England to New York) and negative numbers indicate flow adjustments in the export direction (i.e., from New York to PJM or New England).
- Production Cost Savings – This measures the market efficiency gains (and losses) that resulted from the CTS processes.
    - Projected Savings at Scheduling Time – This measures the expected production cost savings at the time when RTC determines the interchange schedule across the two primary interfaces.[350]
    - Net Over-Projected Savings – This estimates production cost savings that are over-projected. CTS bids are scheduled based partly on forecast prices. If forecast prices deviate from actual prices, transactions may be over-scheduled, under-scheduled,

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349 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.

350 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 355.

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. [351]

- Other Unrealized Savings – This measures production cost savings that are not realized once the following factors are taken into account:
  - Real-time Curtailment[352] - 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[353] - 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[354,355] – This is equal to (Projected Savings – Net Over-Projected Savings - Unrealized Savings).

351 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.

352 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).

353 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).

354 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).

355 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, 2022

			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 > $20	Total	
% of All Intervals w/ Adjustment			66%	23%	**89%**		42%	17%	**59%**	
Average Flow Adjustment (MW)	Net Imports		12	20	**14**		8	-16	**1**	
	Gross		105	139	**114**		70	97	**78**	
Production Cost Savings ($ Million)	Projected at Scheduling Time		$8.9	$12.8	**$21.7**		$2.0	$6.3	**$8.3**	
	Net Over-Projection by:	NY	-$0.5	-$4.1	**-$4.7**		-$0.2	-$0.7	**-$0.9**	
		NE or PJM	$0.1	-$0.5	**-$0.4**		-$0.3	-$5.0	**-$5.3**	
	Other Unrealized Savings		-$0.2	-$1.7	**-$1.9**		-$0.1	-$1.8	**-$1.9**	
	Actual Savings		$8.2	$6.5	**$14.7**		$1.4	-$1.2	**$0.2**	
Interface Prices ($/MWh)	NY	Actual	$66.13	$136.97	**$84.66**	**$83.91**	$55.23	$107.39	**$69.95**	**$68.24**
		Forecast	$67.91	$131.76	**$84.62**	**$83.77**	$56.81	$104.04	**$70.14**	**$68.12**
	NE or PJM	Actual	$64.29	$128.80	**$81.16**	**$81.57**	$53.48	$108.10	**$68.90**	**$65.50**
		Forecast	$63.29	$120.93	**$78.37**	**$78.82**	$55.42	$116.86	**$72.76**	**$68.87**
Price Forecast Errors ($/MWh)	NY	Fcst. - Act.	$1.78	-$5.21	**-$0.05**	**-$0.14**	$1.57	-$3.34	**$0.19**	**-$0.12**
		Abs. Val.	$4.71	$56.42	**$18.24**	**$17.80**	$4.28	$36.21	**$13.29**	**$11.70**
	NE or PJM	Fcst. - Act.	-$1.00	-$7.87	**-$2.80**	**-$2.75**	$1.93	$8.76	**$3.86**	**$3.37**
		Abs. Val.	$4.30	$30.52	**$11.16**	**$11.10**	$5.49	$64.29	**$22.09**	**$19.22**

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 2022. 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.

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.

Figure A-74: Distribution of Price Forecast Errors Under CTS
NE and PJM Primary Interfaces, 2022

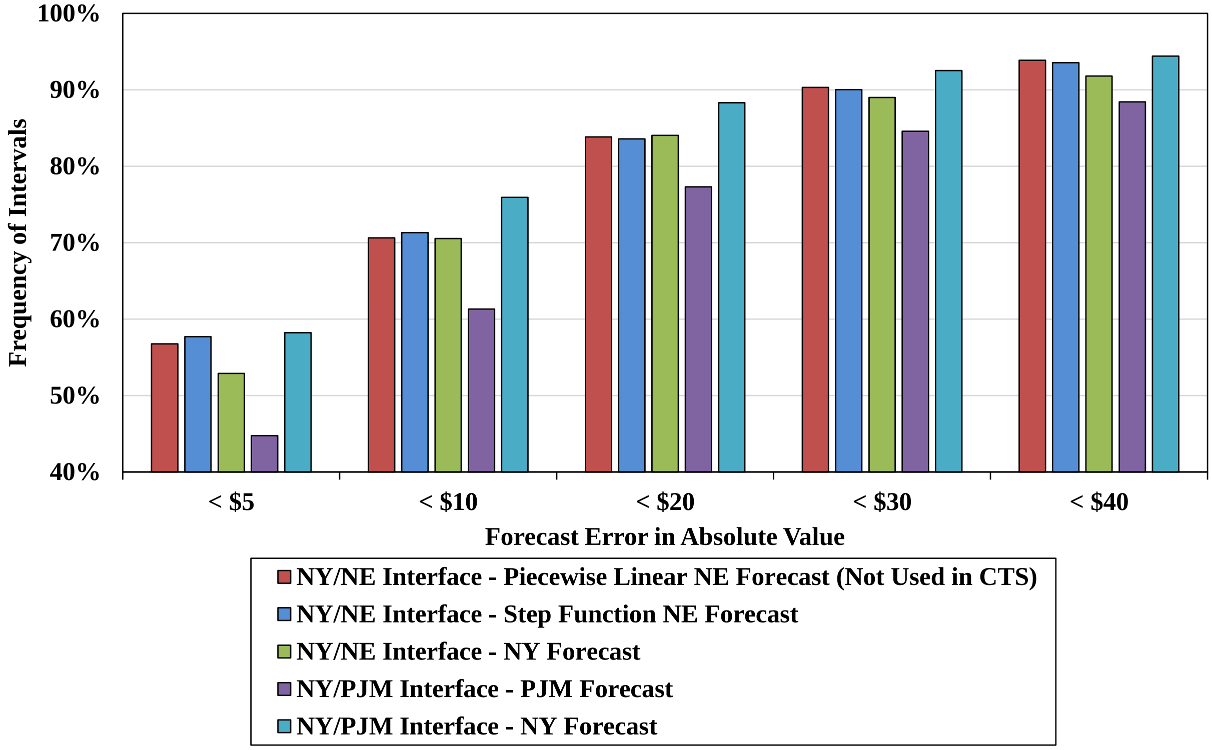


Figure A-75: Example of Supply Curve Produced by ISO-NE and Used by RTC

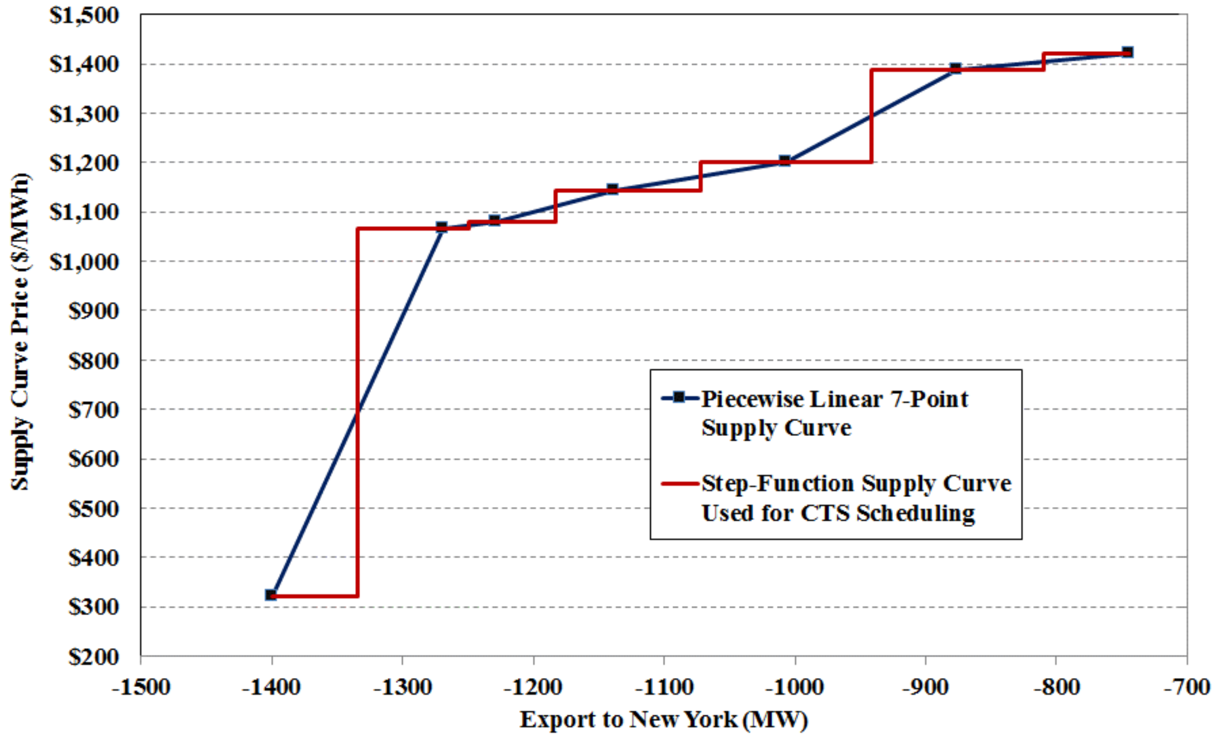


Figure A-74 shows the ISO-NE forecast error in two ways: (a) based on the piece-wise linear curve that is produced by its forecasting model, and (b) based on the step-function curve that the NYISO model uses to approximate the piece-wise linear curve.

Figure A-75 illustrates this with example curves.[356] 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.

D. Evaluation of 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.

Figure A-76 to Figure A-78: Forecast Assumptions Used by RTC to Schedule CTS Transactions and Their Price Impact

Figure A-76 to Figure A-78 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).[357]

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-

356 The two curves are forecasted supply curves used in the market on January 5, 2016.

357 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:

$$Metric_i = (NetInjectionMW_{i,RTC} - NetInjectionMW_{i,RTD}) * (Price_{i,RTC} - Price_{i,RTD})$$ [358]

Hence, for the load forecast in the example above, the metric is:

$$Metric_{load} = 100\text{ MW} * (\$45/\text{MWh} - \$65/\text{MWh}) = -\$2{,}000/\text{hour}$$

For the high-cost generator in the example above, the metric is:

$$Metric_{generator} = -100\text{ MW} * (\$45/\text{MWh} - \$65/\text{MWh}) = +\$2{,}000/\text{hour}$$

For the foregone CTS imports in the example above, the metric is:

$$Metric_{import} = 0\text{ MW} * (\$45/\text{MWh} - \$65/\text{MWh}) = \$0/\text{hour}$$

The metric produces a negative value for the load forecast, indicating that the under-forecast of load was a "detrimental" factor that contributed to the divergence between the RTC forecast price and the actual RTD price. The metric produces a positive value for the generator that responded to the need for additional supply in RTD, indicating that the generator's response was a "beneficial" factor that helped limit the divergence between the RTC forecast price and the actual RTD price. The metric produces a zero value for the foregone CTS imports, recognizing that the divergence was not caused by the CTS imports not being scheduled, but rather that their not being scheduled was the result of poor forecasting.

For PAR-controlled line i, our inconsistency metric is calculated across binding constraints c:

$$Metric_i = (FlowMW_{i,RTC} - FlowMW_{i,RTD}) * \sum_c \{(ShadowPrice_{c,RTC} * ShiftFactor_{i,c,RTC} - ShadowPriceMW_{c,RTD} * ShiftFactor_{i,c,RTD})\}$$

Hence, for a PAR-controlled line that is capable of relieving congestion on a binding constraint, if the flow on the PAR-controlled line is higher in RTD than in RTC and the shadow price of the constraint is higher in RTD than in RTC, the metric will produce a positive value, indicating that the PAR-controlled line had a beneficial inconsistency (i.e., it helped reduce the divergence between RTC and RTD congestion prices). However, if the flow on the PAR-controlled line decreases in RTD while the shadow price is increasing, the metric will produce a negative value, indicating that the PAR-controlled line had a detrimental inconsistency (i.e., it contributed to the

[358] 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.[359]

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.

359 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-81.

Figure A-76 summarizes the RTC/RTD divergence metric results for detrimental factors in 2022, while Figure A-77 provides the summary for beneficial factors. Figure A-78 summarizes the beneficial and detrimental metric results for Transmission Utilization.

Figure A-76: Detrimental Factors Causing Divergence between RTC and RTD
2022

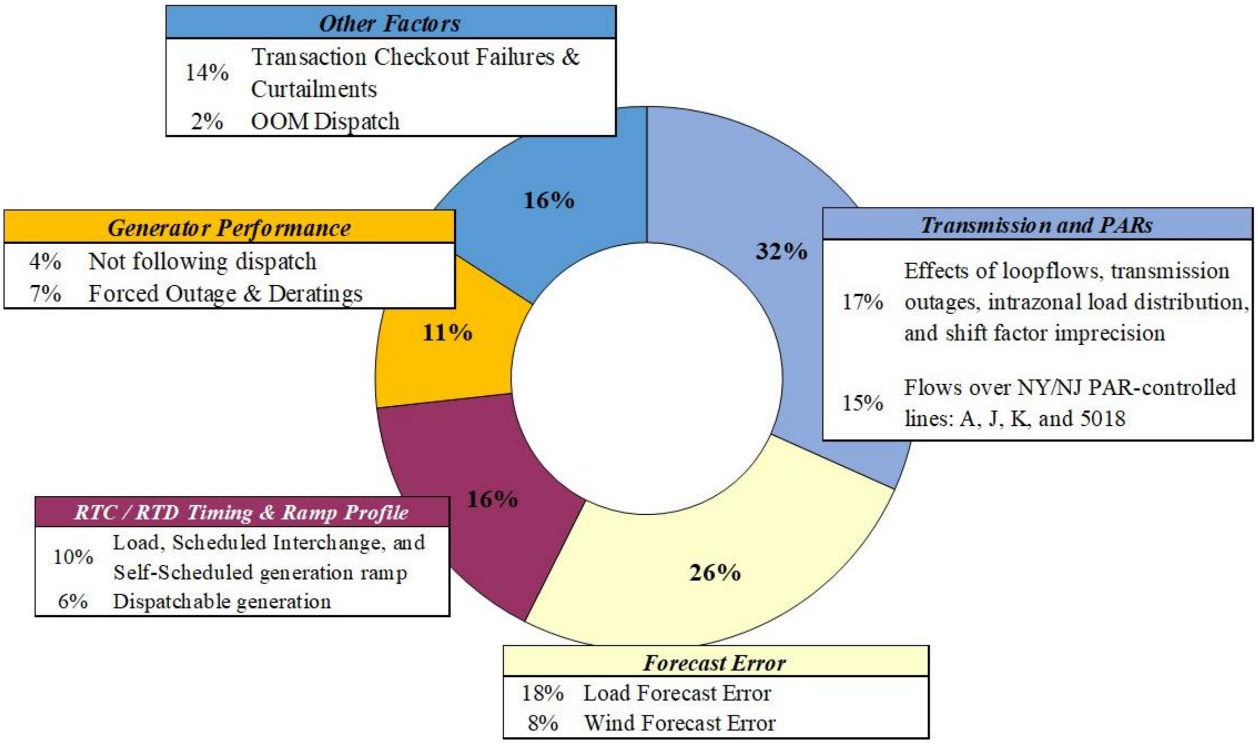
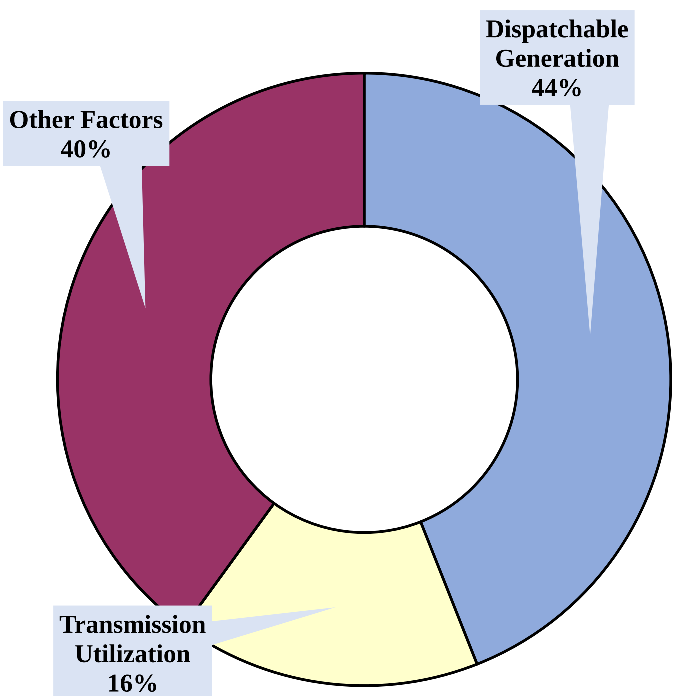
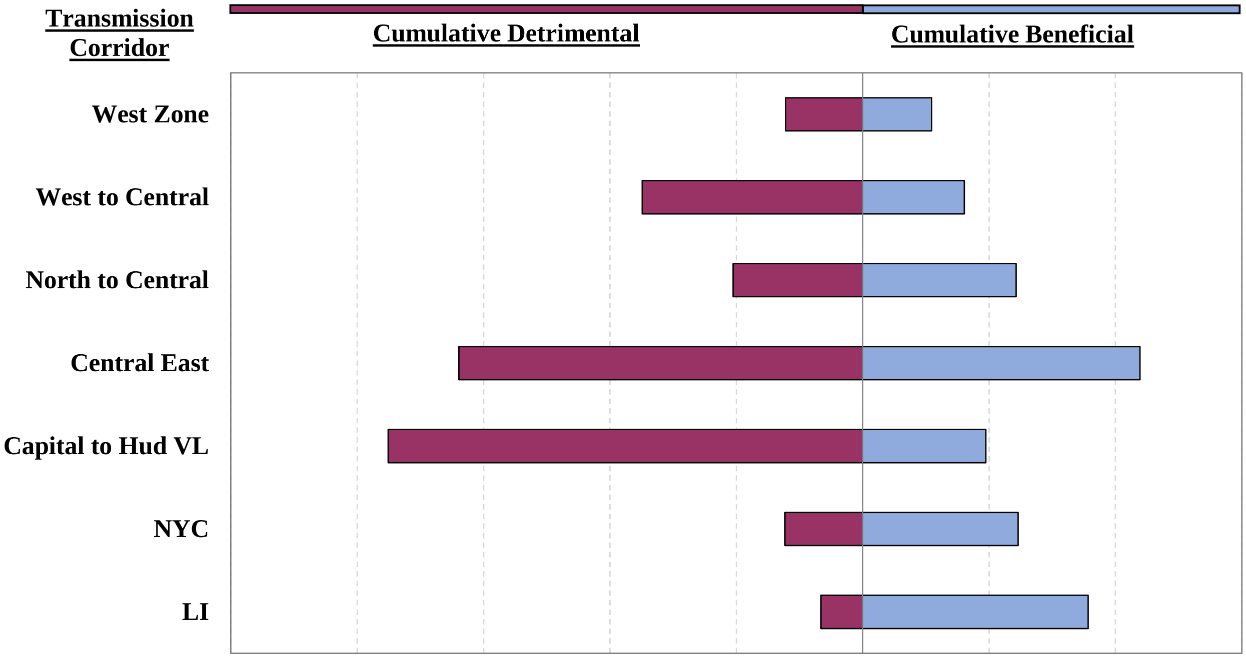


Figure A-77: Beneficial Factors Reducing Divergence between RTC and RTD
2022



"Dispatchable Generation"	
Factors for the redispatch of generators.	
"Other Factors"	
Wind Forecast Error	9%
Ramp Profile	7%
Load Forecast Error	8%
Non-optimized PARs	5%
Not-Following Dispatch	2%
Forced Outage / Derate	4%
OOM Dispatch	2%
Checkout Failures / Curtailment	4%
"Transmission Utilization"	
Includes optimized transmission and PAR operations	

Figure A-78: Effects of Network Modeling on Divergence between RTC and RTD
By Region, 2022



E. Patterns of Key Factors Driving Price Differences between RTC and RTD

The following analyses focus on several key factors contributing to inconsistency between RTC and RTD, which (a) evaluate the magnitude and patterns of forecast errors of these factors and (b) examine how these affect the accuracy of RTC's price forecasting.

Figure A-79 & Figure A-80: Differences in Prices vs Differences in Assumptions of Net Interchanges between RTC and RTD

Figure A-79 shows a histogram of the differences in 2022 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 at the quarter-hour intervals for RTC and RTD.

Figure A-80 shows 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 for 100+ 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-79: Histogram of Differences Between RTC and RTD Prices and Net Interchange
2022

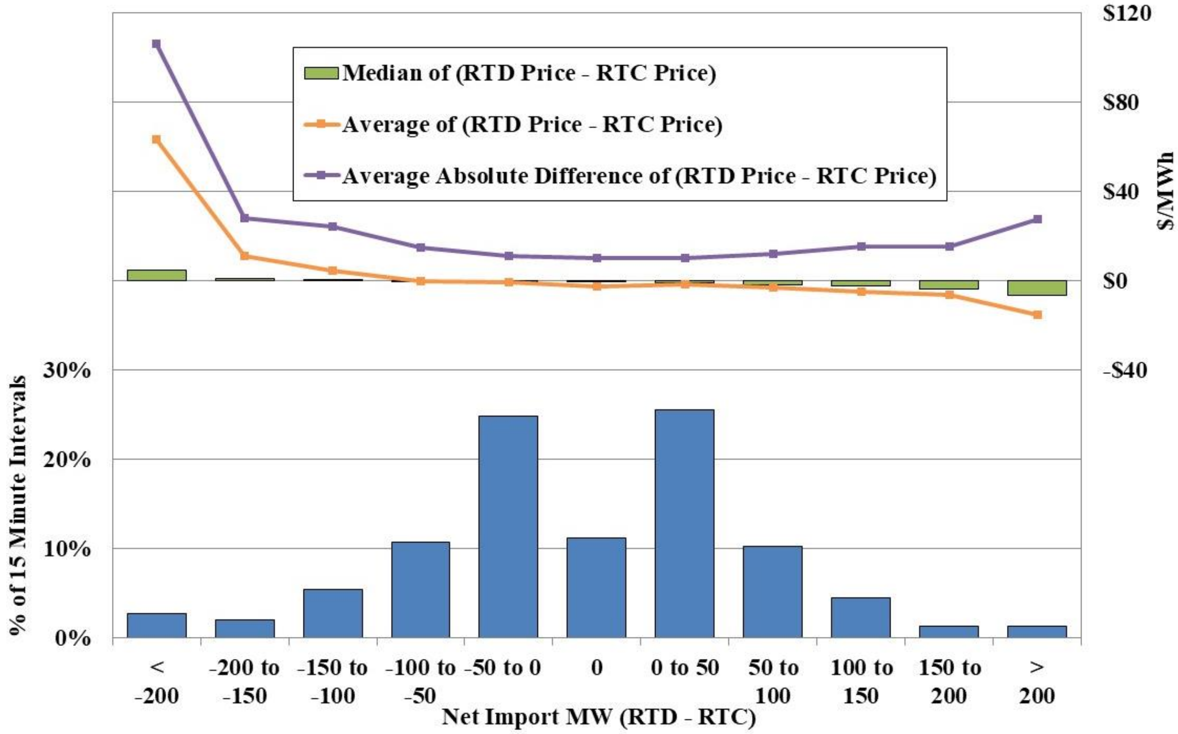


Figure A-80: Differences Between RTC and RTD Prices and Net Interchange Schedules
by Time of Day, 2022

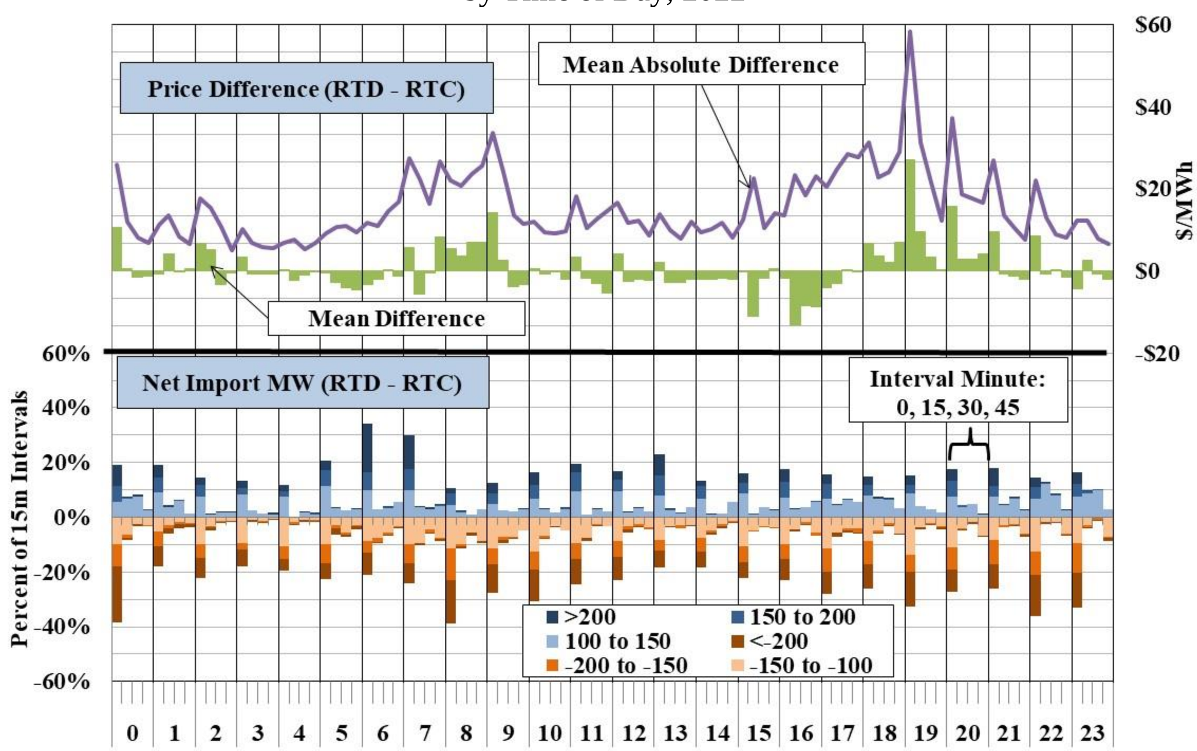


Figure A-81: Illustration of the ramp profiles that are assumed by RTC and RTD

The differences in net interchange schedules between RTC and RTD result from factors such as transaction checkout failures, curtailments by operators, and different ramp assumptions used in RTC and RTD. Figure A-81 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-81: Illustration of External Transaction Ramp Profiles in RTC and RTD

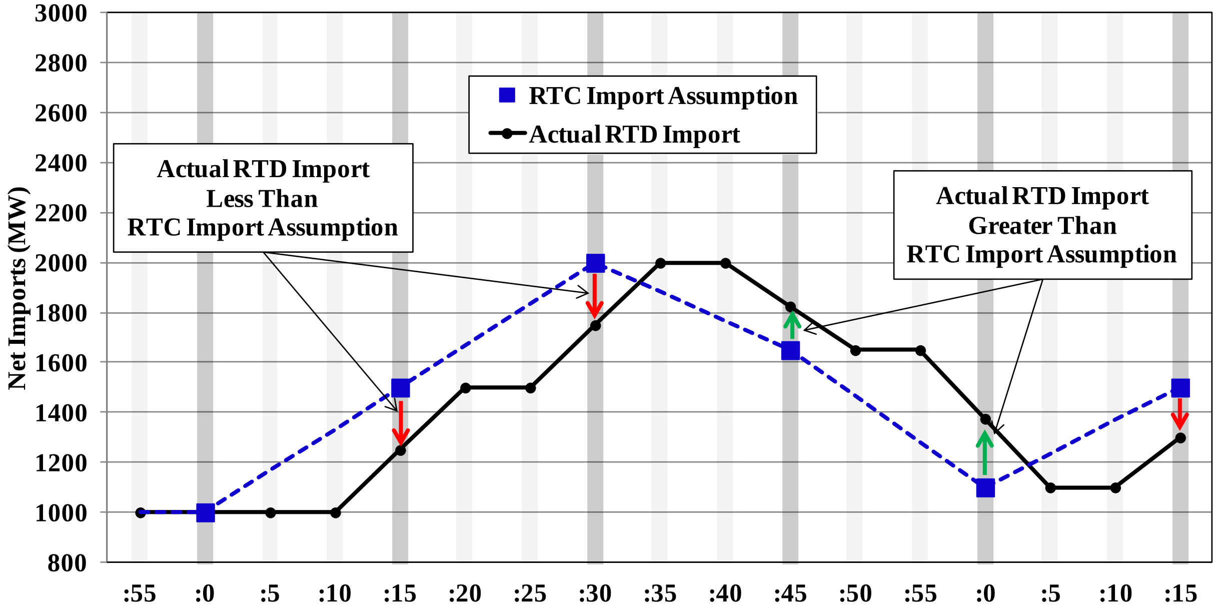


Figure A-82 & Figure A-83: Differences in Prices vs Differences in Load Forecasts between RTC and RTD

Figure A-82 shows a histogram of the differences in systemwide load forecasts (including load biases by operators) between RTC and RTD at the quarter-hour intervals (i.e., at :00, :15, :30, :45) for 2022. For each tranche of the histogram, the figure summarizes the accuracy of the RTC price by showing:

- The average of the RTC LBMP minus the RTD LBMP;
- The median of the RTC LBMP minus the RTD LBMP; and
- The mean absolute difference between the RTD and RTC LBMPs.

LBMPs are shown as zonal-load-weighted prices at the quarter-hour intervals for both RTC and RTD.

Figure A-83 shows these pricing and load forecasting 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 load forecast levels in tranches. The upper portion of the figure summarizes the accuracy of the RTC price forecast by showing:

- The average RTC LBMP minus the average RTD LBMP; and
- The mean absolute difference between the RTD and RTC LBMPs.

Figure A-82: Histogram of Differences Between RTC and RTD Prices and Load Forecasts
2022

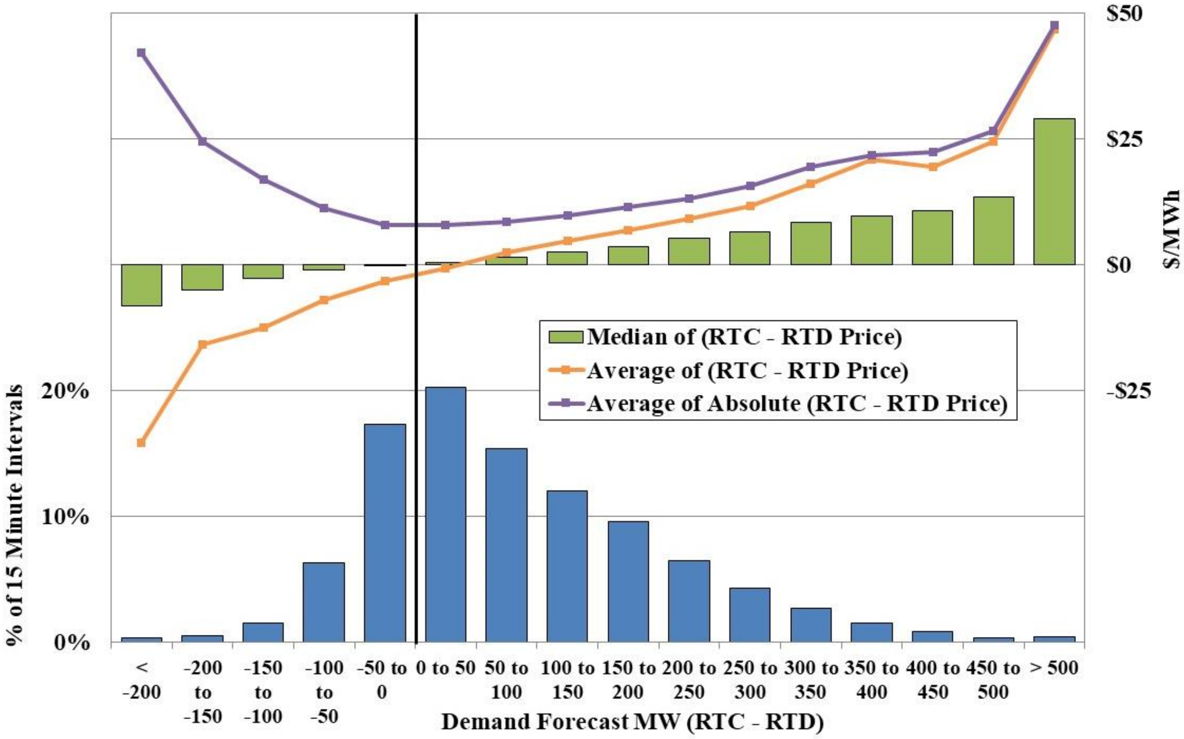


Figure A-83: Differences Between RTC and RTD Prices and Load Forecasts
by Time of Day, 2022

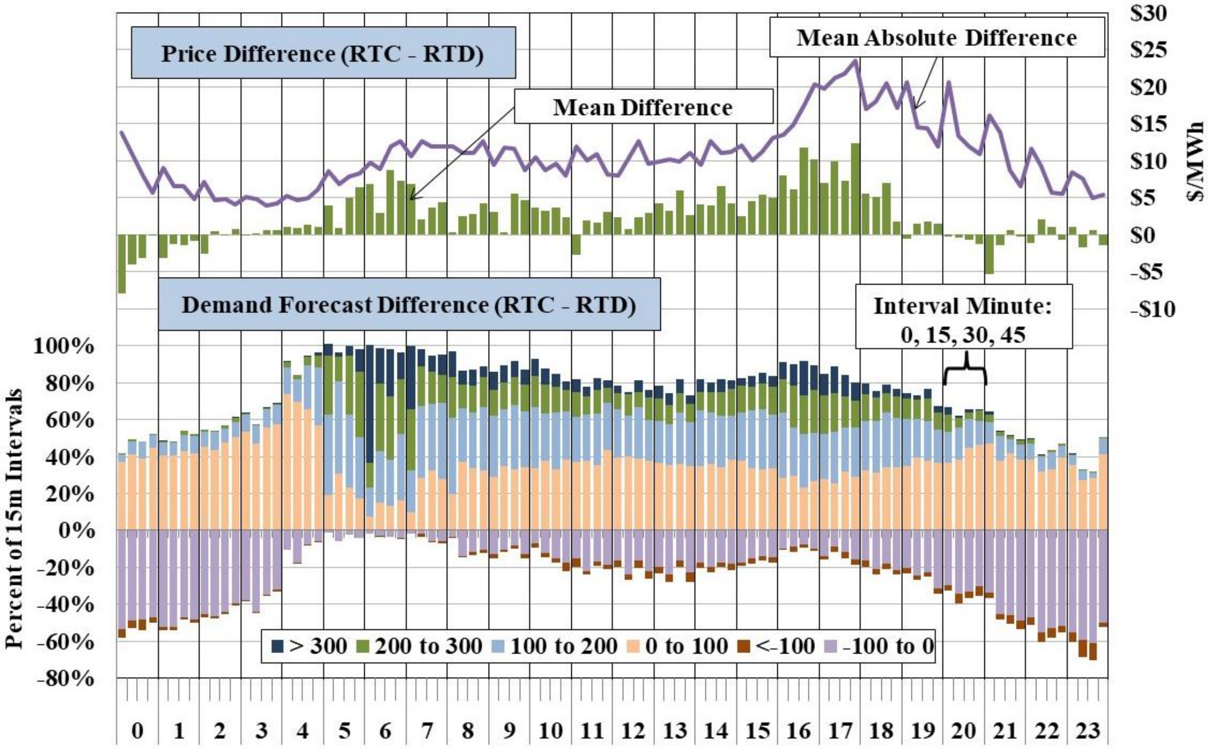


Figure A-84: Differences in Prices vs Differences in Unmodeled Constraint Flows between RTC and RTD

Unmodeled flows on transmission constraints lead to unexpected congestion levels and contribute to inconsistency between RTC and RTD. Figure A-84 illustrates this on the Cricket Valley-Pleasant Valley 345 kV constraint ("the CPV constraint"), which summarizes the differences in unmodeled flows between RTD and RTC and the resulting price impact on select locations in 2022.

The x-axis shows the MW tranches of differences in unmodelled flows on the CPV constraint between RTD and RTC. A positive MW tranche indicates a higher level of unmodeled flows in the constraint congested direction in RTC than in RTD, and vice versa for the negative MW tranches. The top portion of the chart shows the proportion of all 5-minute intervals that fall into each MW tranche on the x-axis. This excludes intervals when the CPV constraint was not binding in both RTC and RTD. The lower portion of the chart shows the resulting price differences at select locations as

> Resulting Price Difference = Difference in Constraint Shadow Cost × Location-specific Shift Factor on the Constraint

Figure A-84: Differences Between RTC and RTD Prices and Unmodeled Constraint Flows
The CPV Constraint, 2022

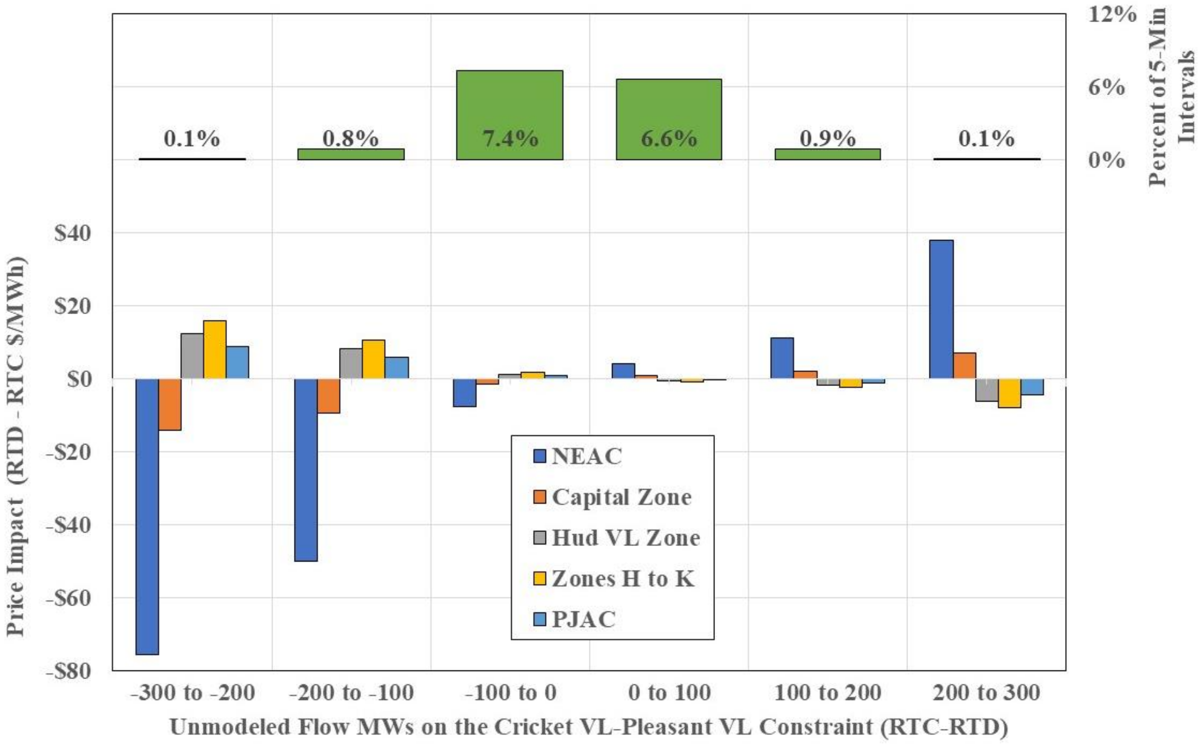


Figure A-85 & Figure A-86: Curtailments on RTC/RTD Divergence

Figure A-85 compares the frequency of external transaction curtailments by month in 2021 and 2022. This is shown separately for the Ontario interface, the Quebec interface, the primary New England interface, the Neptune interface, and the primary PJM interface. All other interfaces are grouped together. For one particular interface, one hour is counted towards the curtailment frequency if the quantity of net curtailments in either import direction or export direction was more than 100MW in any intervals within the hour.

Figure A-86 shows the 10 days in 2022 which contributed the most significant impact to the category of detrimental curtailments causing divergence between RTD and RTC. Of this category, the bulk of the impact (77.4 percent) is contained within the top 10 days.

Figure A-85: Number of Hours with External Transaction Curtailments by Interface
By Month, 2021-2022

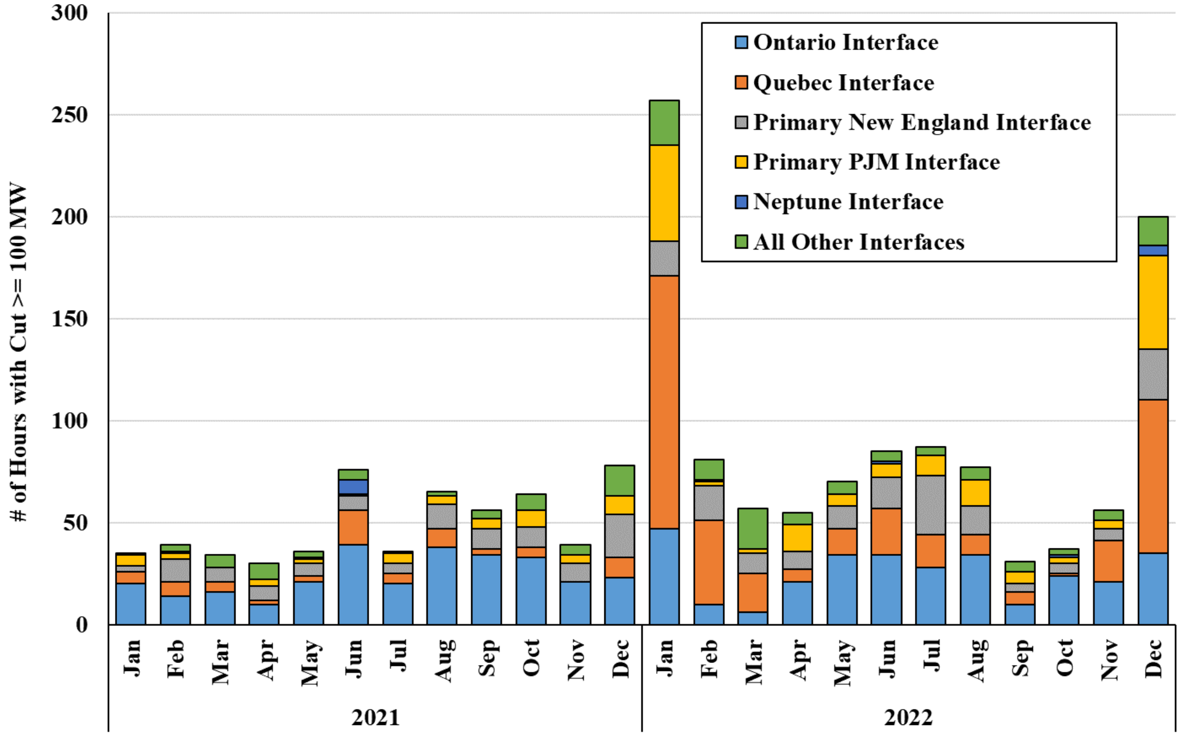
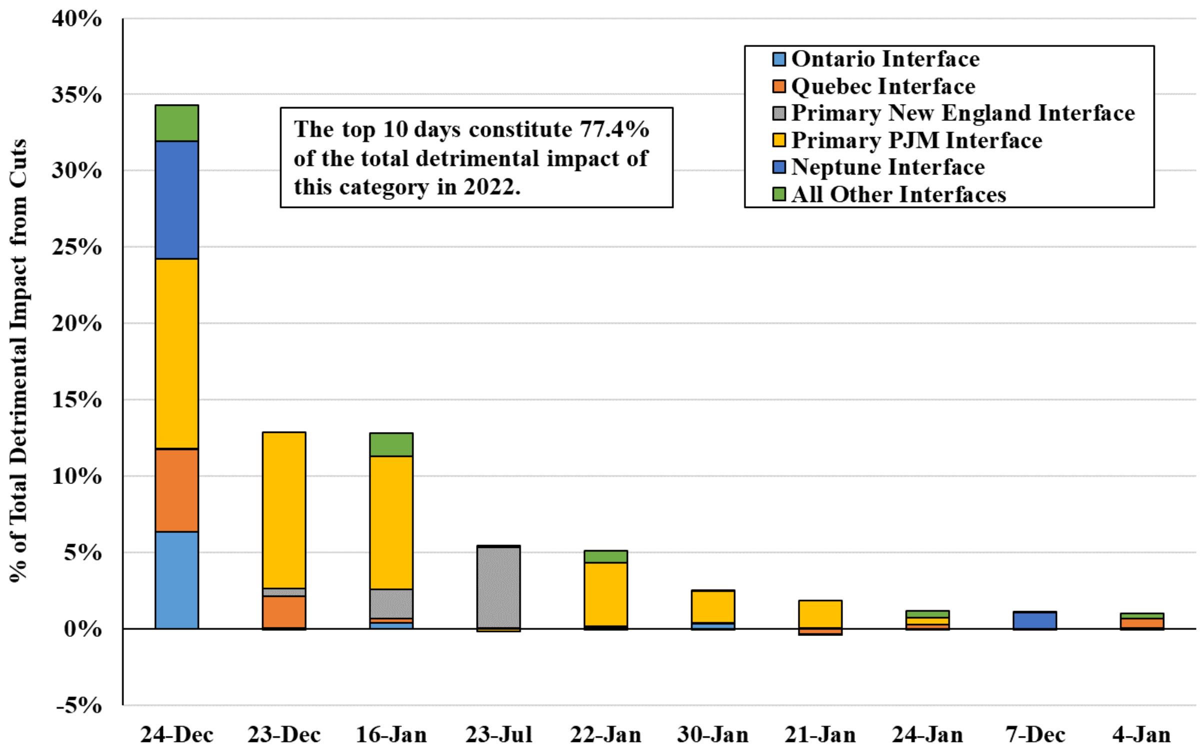


Figure A-86: Top 10 Days in Detrimental Curtailment Category
2022



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 2022:

- *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 Congestion 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.[360] 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-

360 10-minute units can start quickly enough to provide 10-minute non-synchronous reserves.

minute units when it is economic to do so.[361] 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-87: Efficiency of Gas Turbine Commitment

Figure A-87 evaluates the efficiency of gas turbine commitment (including both fixed-block and dispatchable GTs) from 2020 to 2022. The evaluation focuses on economic commitments that are made by RTC, RTD, or RTD-CAM, [362] 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.

361 30-minute units can start quickly enough to provide 30-minute non-synchronous reserves, but not quickly enough to provide 10-minute reserves.

362 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.

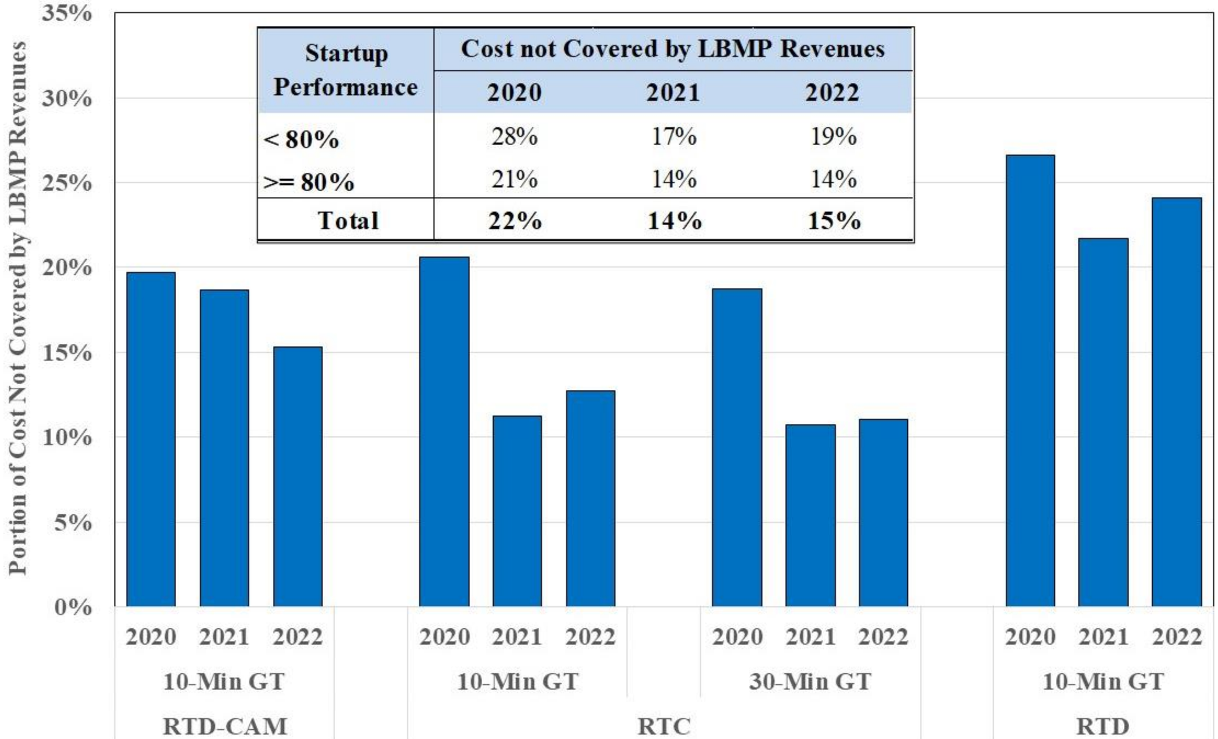
- GTs that are started efficiently to address a transient shortage (e.g. transmission constraint violation lasting less than one hour, or a reserve pickup by RTD-CAM) may lower LBMPs and appear uneconomic over the commitment period.

- The start-up and minimum generation costs were not incorporated in the LBMP-setting logic until 2021.

Figure A-87 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).[363]

Figure A-87: Efficiency of Gas Turbine Commitment

2020-2022



363 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-88 - Figure A-89: Combined-Cycle Unit Duct Burner Capacity and Availability in New York

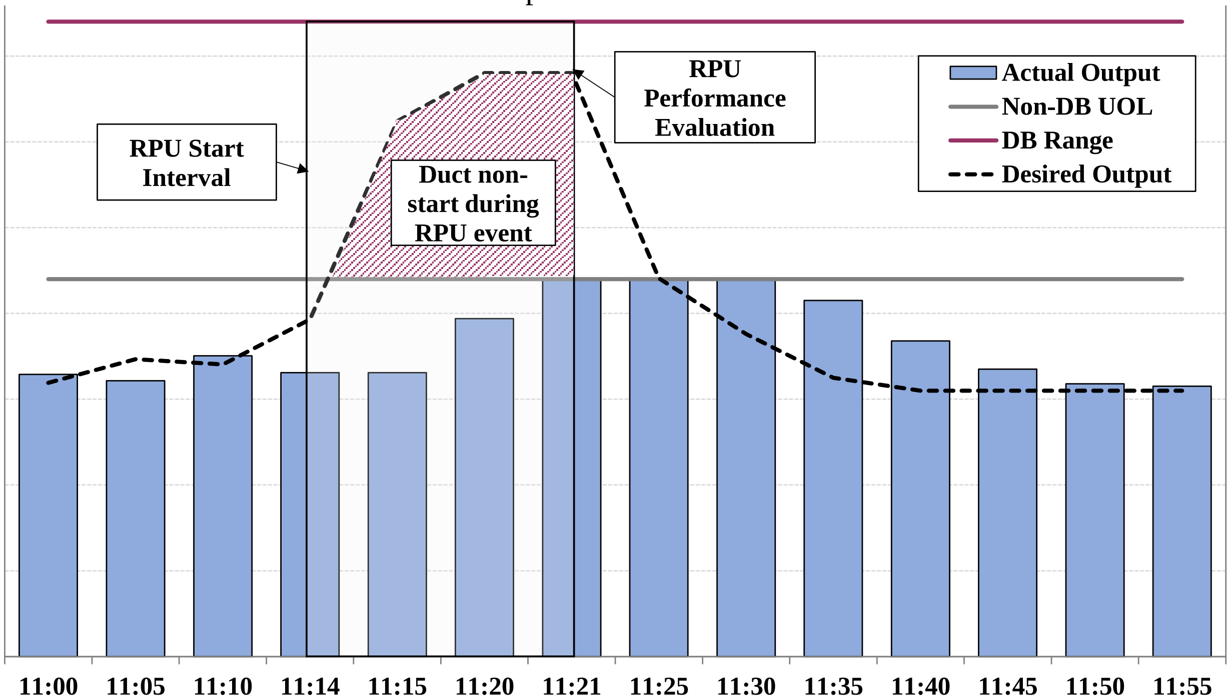
Most combined cycle units in New York have a duct burner, which uses supplementary firing to increase the heat energy of a gas turbine's exhaust, making it possible to increase the output of a downstream heat-recovery steam generator. This additional output can be offered into the energy market as a 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	6	42	47
Genesee	1	9	10
Central	7	38	39
North	3	31	31
MHK VL	2	13	15
Capital	10	209	189
HUD VL	5	174	179
NYC	7	280	312
Long Island	3	90	96
NYCA Total	**44**	**886**	**917**

Figure A-88 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-88: Duct Burner Real-Time Dispatch Issue
Example of a Failed RPU



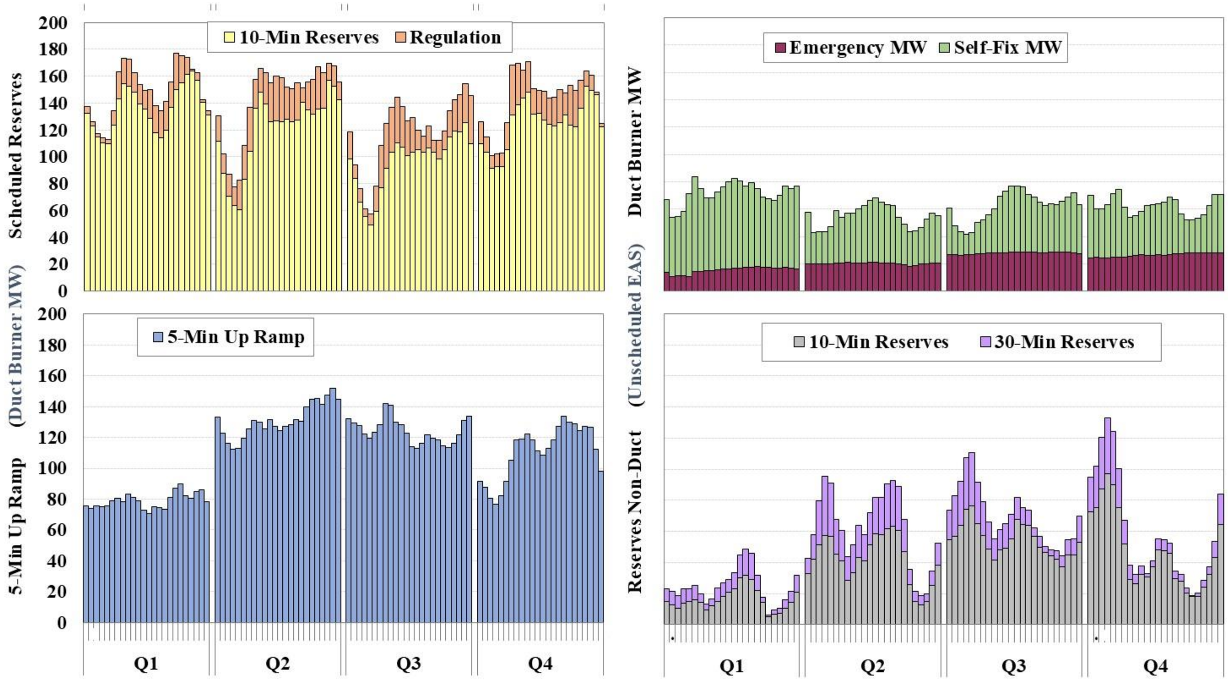
In the figure, the two lines show the levels where resource capacity shifts from baseload without duct burners (gray line) to the duct burner range (red line). Capacity values are not given for confidentiality purposes. The blue bars show the actual output produced by the resource in each RTD and RTD-CAM 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-89 examines duct burner availability in the real-time market for each quarter of 2022. The quantities in the charts are calculated for each 5-minute interval and then aggregated to the hourly level.

The two charts on the left side show the amount of duct burner capacity scheduled or made available for scheduling within the timeframes that are unlikely deliverable for energy and reserves. These values show: (a) the average amount of MWs scheduled to provide 10-minute spinning reserves and regulation services; and (b) the amount of 5-minute up-ramping capability assumed to be available by duct burners.

The two charts on the right side show capacity that was not made available in offers for either energy and/or reserves from units with duct burners, including: (a) the average amount of duct burner capacity unavailable in real-time because of no offer in this range (labeled as 'Emergency MW' or non-dispatchable due to inflexible self-schedule level (labeled as 'Self-Fix MW'); and (b) the average amount of baseload capacity that was available but not offered for 10-minute and 30-minute reserves in real-time because the units were disqualified from offering these reserves.

Figure A-89: Evaluation of Duct-Burner Availability in Real-Time
2022



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-90 - Figure A-92 & Table A-10: Average GT Performance after a Start-Up Instruction

Figure A-90 to Figure A-92 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) .[364] The figure reports the average performance in 2021 and 2022. 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).[365] Figure A-90 shows the performance evaluation for all GTs while Figure A-91 and Figure A-92 show the same evaluation separately for 10-minute and 30-minute GTs. Since 30-

364 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.

365 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.

minute GTs cannot be started by either RTD-CAM or RTD, the two categories are excluded in Figure A-92.

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 2022 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 2022 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: "51 GTs exhibited a response rate of 80 to 90 percent during economic starts in 2022, 51 of them were audited 163 times in total with 19 failures".

Figure A-90: Average GT Performance by Type after a Start-Up Instruction

Economic Starts vs Audit, 2021-2022

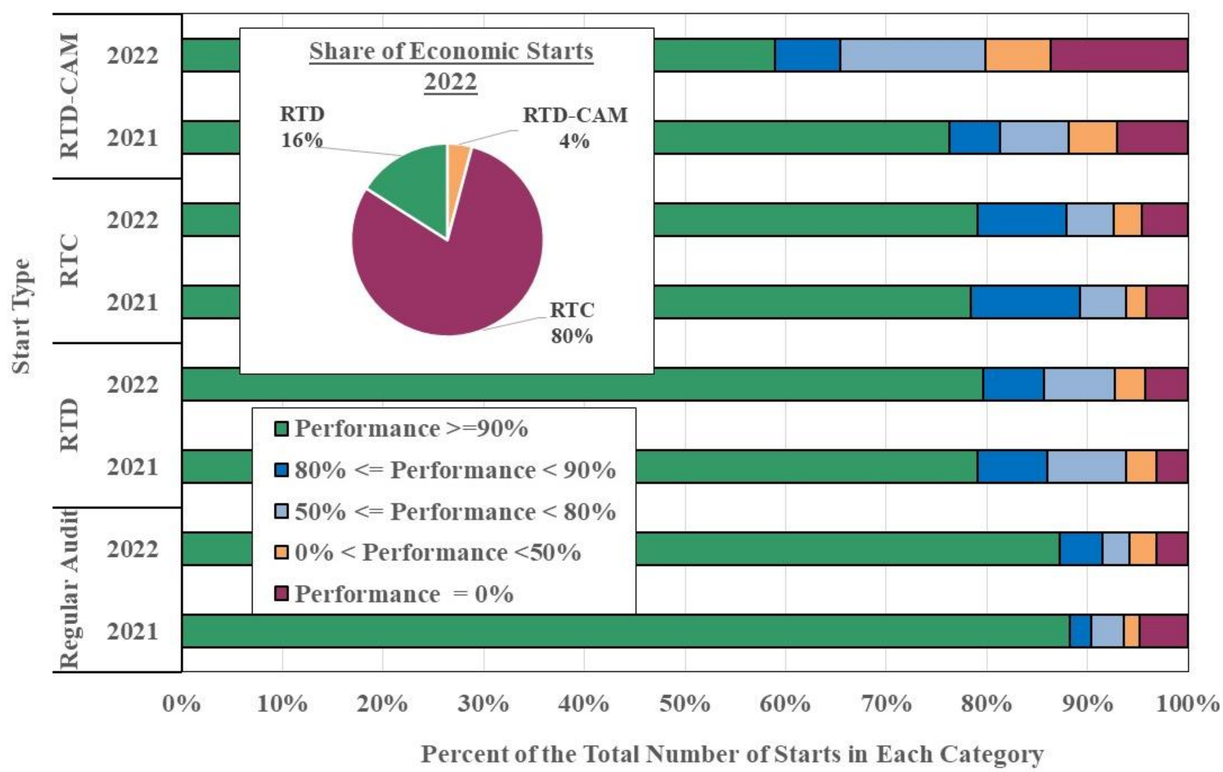


Figure A-91: Average GT Performance by Type after a Start-Up Instruction
Economic Starts vs Audit, for 10-Minute GTs, 2021-2022

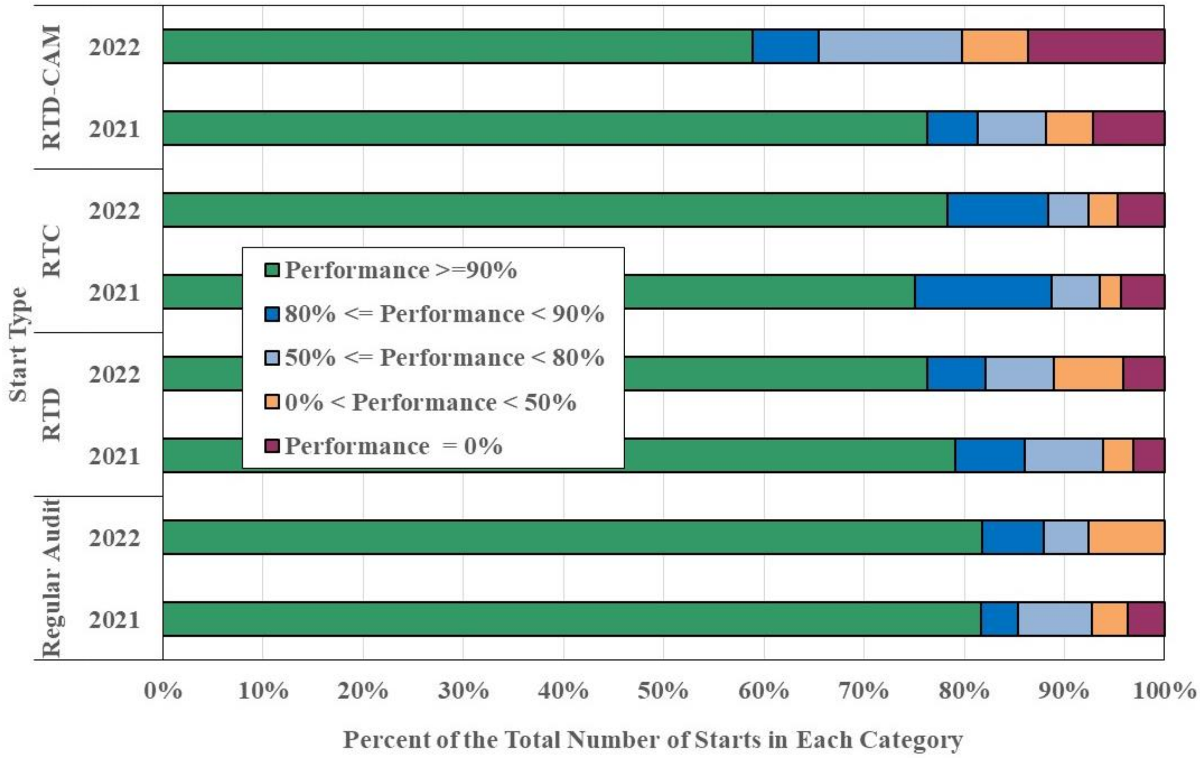


Figure A-92: Average GT Performance by Type after a Start-Up Instruction
Economic Starts vs Audit, for 30-Minute GTs, 2021-2022

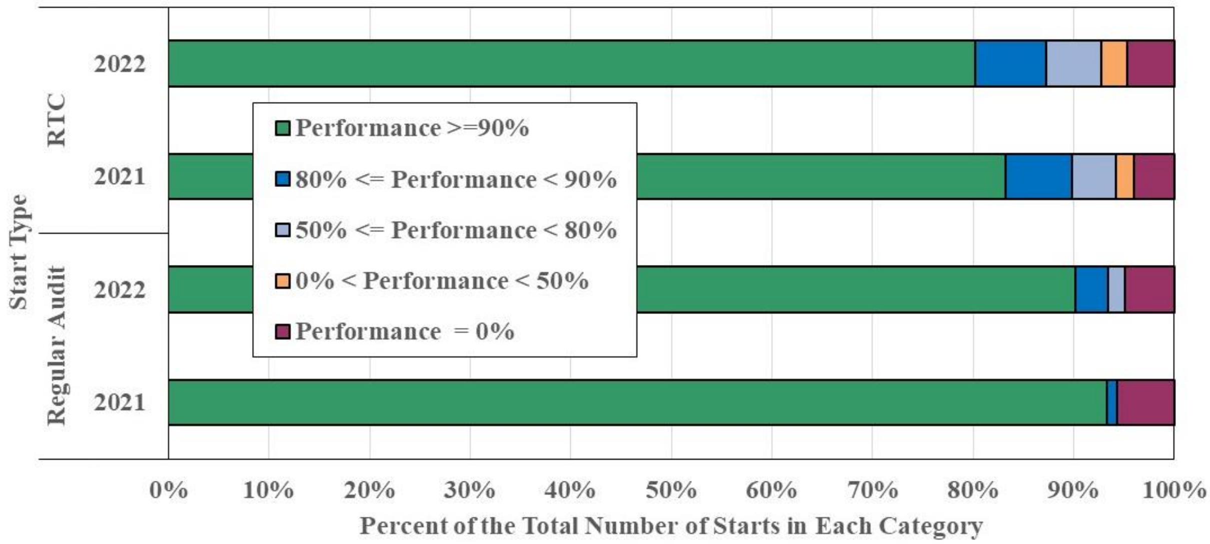


Table A-10: Economic GT Start Performance vs. Audit Results
2022

Economic GT Start Performance vs. Audit Results (Jan - Dec 2022)				
Economic GT Starts (RTC, RTD, and RTD-CAM)		GT Audit Results		
Performance Category	No. of Units	No. of Audits	Unique GTs Audited	No. of Audit Failures
Not Evaluated [1]	27	27	23	2
0% - 10%	1	2	1	1
10% - 20%	1	1	1	0
20% - 30%	0	0	0	0
30% - 40%	2	4	2	2
40% - 50%	2	5	2	2
50% - 60%	4	10	4	3
60% - 70%	2	8	2	5
70% - 80%	9	27	9	11
80% - 90%	51	163	51	19
90% - 100%	41	181	41	21
TOTAL	**140**	**428**	**136**	**66**

Note: 1. Includes 17 units that were never started by RTD, RTC, or RTD-CAM (excluding self-schedules) in 2022 and 10 units for which run data was not available.

Figure A-93: Use of Operating Reserves to Manage Congestion in New York City

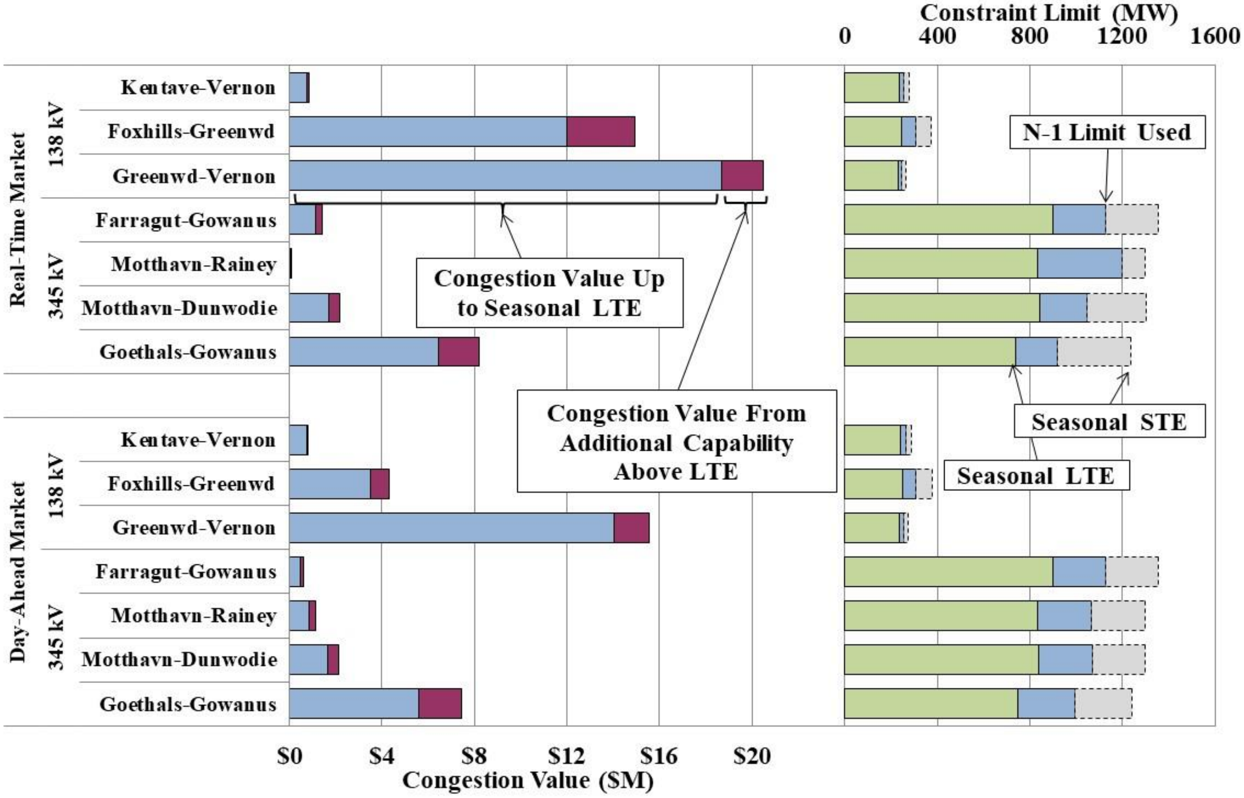
The NYISO sometimes operates a facility above its Long-Term Emergency ("LTE") rating if post-contingency actions (e.g., deployment of operating reserves) would be available to quickly reduce flows to LTE. The use of post-contingency actions is important because it allows the NYISO to increase flows into load centers and reduce congestion costs. However, the service provided by these actions are not properly compensated.

Figure A-93 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 2022. The blue bars represent the congestion values measured up to the seasonal LTE ratings of the facilities.[366] The red bars represent the congestion values measured for the additional transfer capability above LTE.[367] 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.

366 Congestion value up to seasonal LTE = constraint shadow cost × seasonal LTE rating summed across all market hours / intervals.

367 Congestion value for additional capability above LTE = constraint shadow cost × (modeled constraint limit - seasonal LTE rating) summed across all market hours / intervals.

Figure A-93: Use of Operating Reserves to Manage N-1 Constraints in New York City
Limits Used vs Seasonal LTE Ratings, 2022



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.[368] 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.[369]

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

369 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.

Ramapo PARs have been used for the M2M process since its inception, while ABC and JK PARs were incorporated into this process later in May 2017 following the expiration of the ConEd-PSEG Wheel agreement. The NYISO and PJM have an established process for identifying constraints that will be on the list of pre-defined flow gates for Re-dispatch Coordination and PAR Coordination.[370]

Figure A-94: 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 2022.

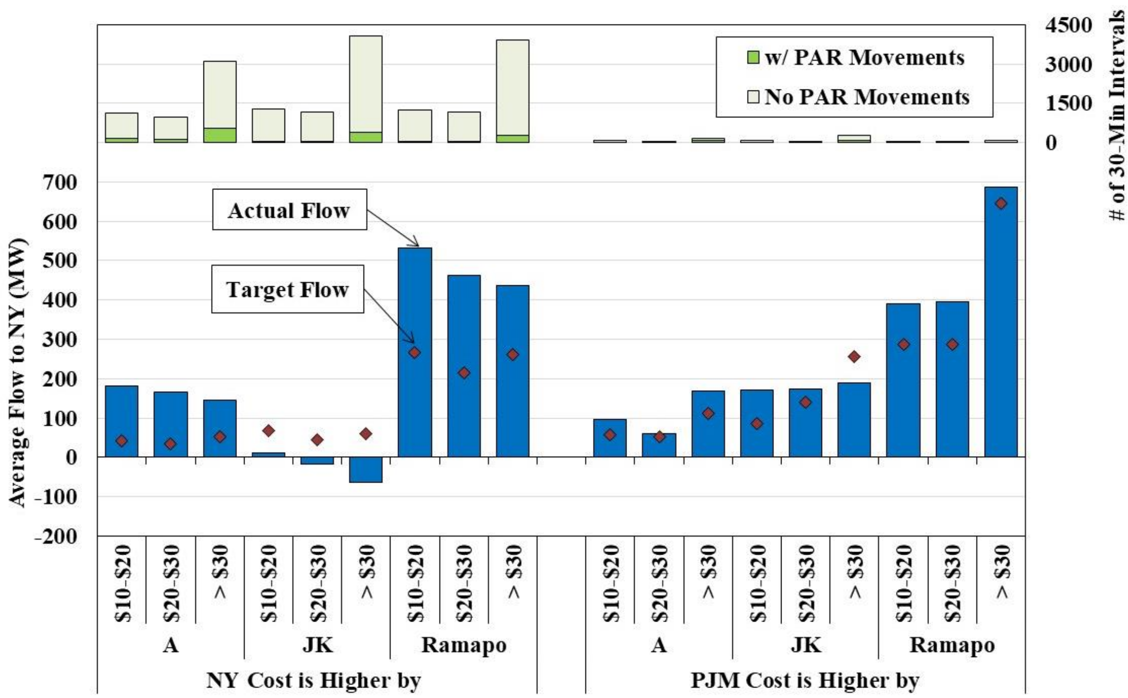
Figure A-94 evaluates operations of these NY-NJ PARs under M2M with PJM in 2021 during periods of noticeable congestion differential between NY and PJM. For each PAR group in the figure, the evaluation is done for the following periods:

- 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;

Figure A-94: NY-NJ PAR Operation under M2M with PJM

2022



370 The list of pre-defined flowgates, *Coordinated Flowgates and Entitlements*, is posted here in the sub-group "Notices" under "General Information".

The market cost is measured as the constraint shadow price multiplied by the PAR shift factor, summed over relevant M2M constraints in each 5-minute market interval and then averaged over each half-hour period.

In the figure, the top portion shows two stacked bars for each evaluation group, representing the total number of 30-minute intervals with and without any PAR tap movements; while the bottom portion shows average actual PAR flows (blue bar), compared with their average M2M targets (red diamond).

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.[371] Such lines are analyzed in Section V.D of the Appendix, which evaluates external transaction scheduling. Second, "optimized" PAR-controlled lines are optimized in the sense that they are normally adjusted by the local TO in order to reduce generation redispatch (i.e., to minimize production costs) in the day-ahead and real-time markets. Third, "non-optimized" PAR-controlled lines are scheduled according to various operating procedures that are not primarily focused on reducing production costs in the day-ahead and real-time markets. This sub-section evaluates the use of non-optimized PAR-controlled lines.

Table A-11 and Figure A-95: 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 2022.

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 2022. 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).

371 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.

- 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.[372]

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.[373] 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.

Figure A-95 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.

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372 For example, if 100 MW flows from Lake Success to Jamaica during one hour, the price at Lake Success is $50 per MWh, and the price at Jamaica is $60 per MWh, then the estimated production cost savings is $1,000 (=100 * $10). This is because each MW of flow saves $10 by allowing a $60 per MWh resource in New York City to ramp down and be replaced by a $50 per MWh resource in Long Island. This method of calculating production cost savings tends to under-estimate the actual production cost savings when power flows from the low-priced region to the high-priced region, since if flows in the efficient direction were reduced, the cost of the marginal resource in the importing region would rise while the cost of the marginal resource in the exporting region would fall. However, this method of calculating production cost savings tends to over-estimate the actual production cost increases when power flows from high-priced region towards the low-priced region, since if flows were reduced, the cost differential between the marginal resources in each region would converge.

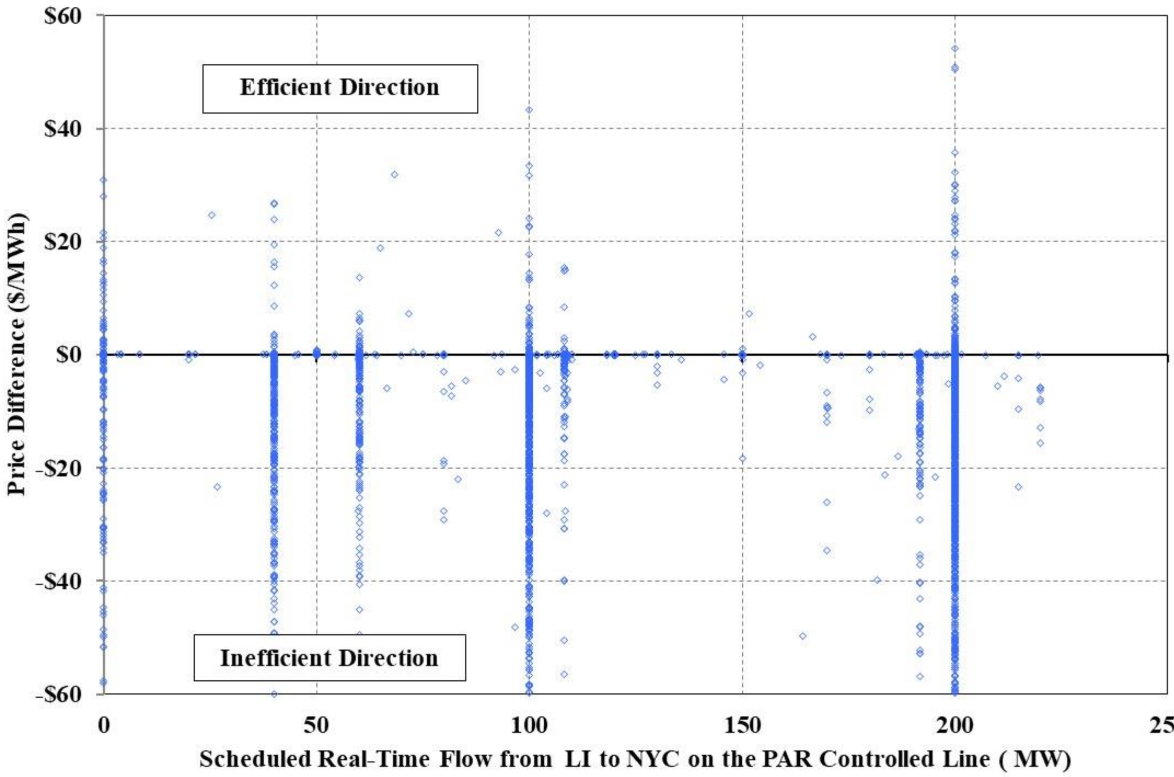
373 For example, if 100 MW is scheduled from the low-priced region to the high-priced region in the day-ahead market, the day-ahead schedule is considered *efficient direction*, and if the relative prices of the two regions is switched in the real-time market and the flow was reduced to 80 MW, the adjustment is shown as -20 MW and the real-time schedule adjustment is considered *efficient direction* as well.

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.

Table A-11: Efficiency of Scheduling on Non-Optimized PAR Controlled Lines
2022

	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					-15	$13.35	52%	$0.1
New England to NYCA								
Sand Bar	-72	-$35.74	90%	$22	0.1	-$32.91	55%	$0.8
PJM to NYCA								
Waldwick	64	$14.90	62%	$22	-33	$14.28	48%	-$12
Ramapo	289	$18.76	83%	$77	199	$18.58	73%	$30
Goethals	34	$16.93	65%	$12	114	$12.83	70%	$10
Long Island to NYC								
Lake Success	129	-$9.77	3%	-$13	-1	-$10.21	46%	-$0.1
Valley Stream	92	-$10.08	4%	-$9	0.4	-$11.18	41%	-$0.2

Figure A-95: Efficiency of Scheduling on PAR Controlled Lines
Lake Success-Jamaica Line – 2022



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 2022 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).[374,375] RTD and RTC assume the flow over these lines will remain fixed in future intervals,[376] 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.

374 These lines are discussed further in Subsection D.

375 M2M coordination is discussed further in Subsection C.

376 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.

- 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.

- 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
2022

	Power Balance		West Zone Lines		Central East		Upstate to Long Island		Intra-LI Constraints		Capital to Hud VL		NYC Load Pockets		North to Central		West to Central	
Average Transfer Limit	**n/a**		**260**		**1084**		**761**		**254**		**751**		**358**		**335**		**200**	
Number of Price Spikes	**606**		**1181**		**1883**		**522**		**787**		**950**		**1126**		**807**		**1115**	
Average Constraint Shadow Price	**$380**		**$556**		**$539**		**$397**		**$527**		**$1,092**		**$499**		**$545**		**$571**	
Source of Increased Constraint Cost:	(MW)	(%)	(MW)	(%)	(MW)	(%)	(MW)	(%)	(MW)	(%)	(MW)	(%)	(MW)	(%)	(MW)	(%)	(MW)	(%)
Scheduled By RTC	**209**	**68%**	**0**	**0%**	**33**	**45%**	**30**	**56%**	**6**	**50%**	**11**	**27%**	**4**	**36%**	**3**	**27%**	**2**	**22%**
External Interchange	113	37%	0	0%	16	22%	11	20%	1	8%	7	17%	0	0%	2	18%	2	22%
RTC Shutdown Resource	71	23%	0	0%	11	15%	17	31%	4	33%	3	7%	3	27%	0	0%	0	0%
Self Scheduled Shutdown/Dispatch	25	8%	0	0%	6	8%	2	4%	1	8%	1	2%	1	9%	1	9%	0	0%
Flow Change from Non-Modeled Facto	**12**	**4%**	**3**	**100%**	**29**	**40%**	**7**	**13%**	**3**	**25%**	**27**	**66%**	**6**	**55%**	**2**	**18%**	**5**	**56%**
Loop Flows & Other Non-Market	5	2%	2	67%	8	11%	4	7%	2	17%	20	49%	4	36%	1	9%	3	33%
Fixed Schedule PARs	0	0%	1	33%	20	27%	3	6%	1	8%	7	17%	2	18%	1	9%	2	22%
Redispatch for Other Constraint (OOM)	7	2%	0	0%	1	1%	0	0%	0	0%	0	0%	0	0%	0	0%	0	0%
Other Factors	**86**	**28%**	**0**	**0%**	**11**	**15%**	**17**	**31%**	**3**	**25%**	**3**	**7%**	**1**	**9%**	**6**	**55%**	**2**	**22%**
Load	45	15%	0	0%	8	11%	11	20%	1	8%	3	7%	0	0%	3	27%	0	0%
Generator Trip/Derate/Dragging	17	6%	0	0%	2	3%	6	11%	2	17%	0	0%	1	9%	0	0%	0	0%
Wind	24	8%	0	0%	1	1%	0	0%	0	0%	0	0%	0	0%	3	27%	2	22%
Total	**307**		**3**		**73**		**54**		**12**		**41**		**11**		**11**		**9**	
Redispatch for Other Constraint (RTD)	**65**		**1**		**13**		**3**		**1**		**3**		**8**		**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,[377] 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 actual regulation movement versus assumed common multiplier.

Figure A-96 & Figure A-97: Regulation Movement-to-Capacity Ratio

Figure A-96 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.

377 The uniform Regulation Movement Multiplier was changed from 13 to 8 on August 31, 2021.

Figure A-96: Distribution of Actual Regulation Movement-to-Capacity Ratio
From a Sample Day

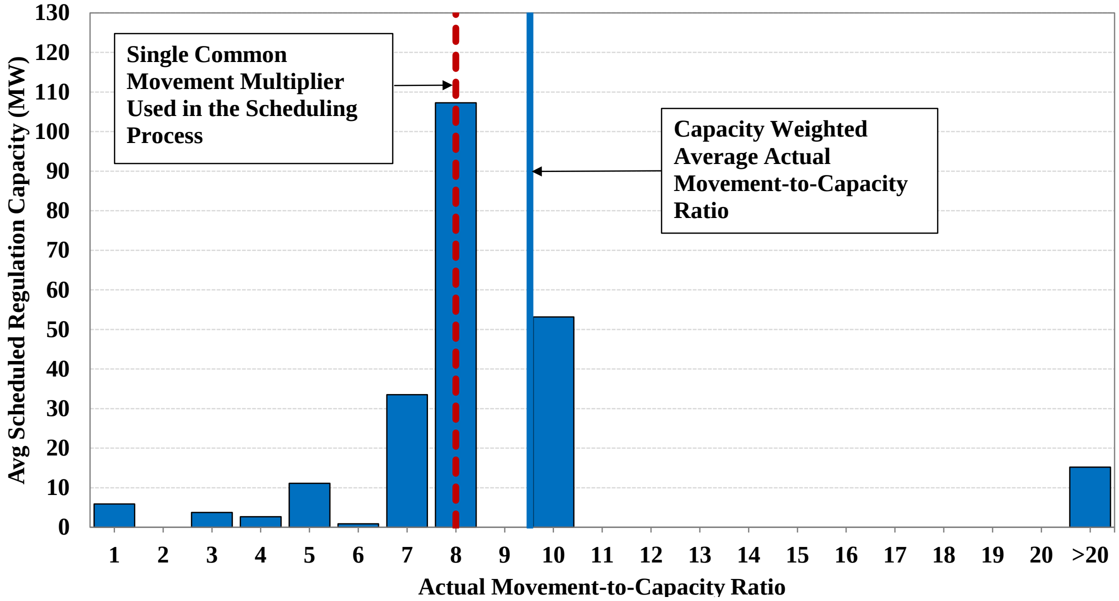
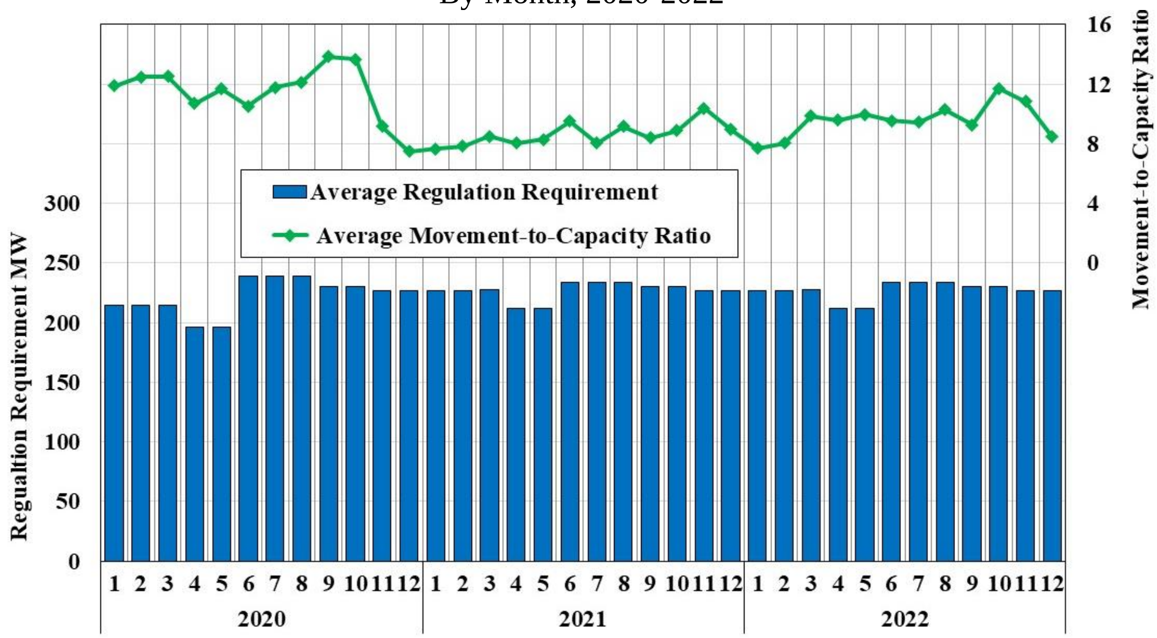


Figure A-97 tracks the variation of regulation movement-to-capacity ratio in recent years, summarizing the following quantities by month:

- Average regulation requirement – The regulation requirement varies by hour by season. This is the hourly average regulation requirement for each month.
- Average actual regulation movement-to-capacity ratio – This is calculated as total regulation movement MW from all resources divided by total scheduled regulation capacity in each month.

Figure A-97: Regulation Requirement and Movement-to-Capacity Ratio
By Month, 2020-2022



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 2022:

- Shortages of operating reserves and regulation (evaluated in this Subsection); and
- Transmission shortages (evaluated in Subsection H).

Figure A-98: 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-98 summarizes physical ancillary services shortages and their effects on real-time prices in 2021 and 2022 for the following eight categories: [378]

- 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,

378 See *NYISO Ancillary Services Manual* for more details.

$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. [379]

- 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.
- 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.

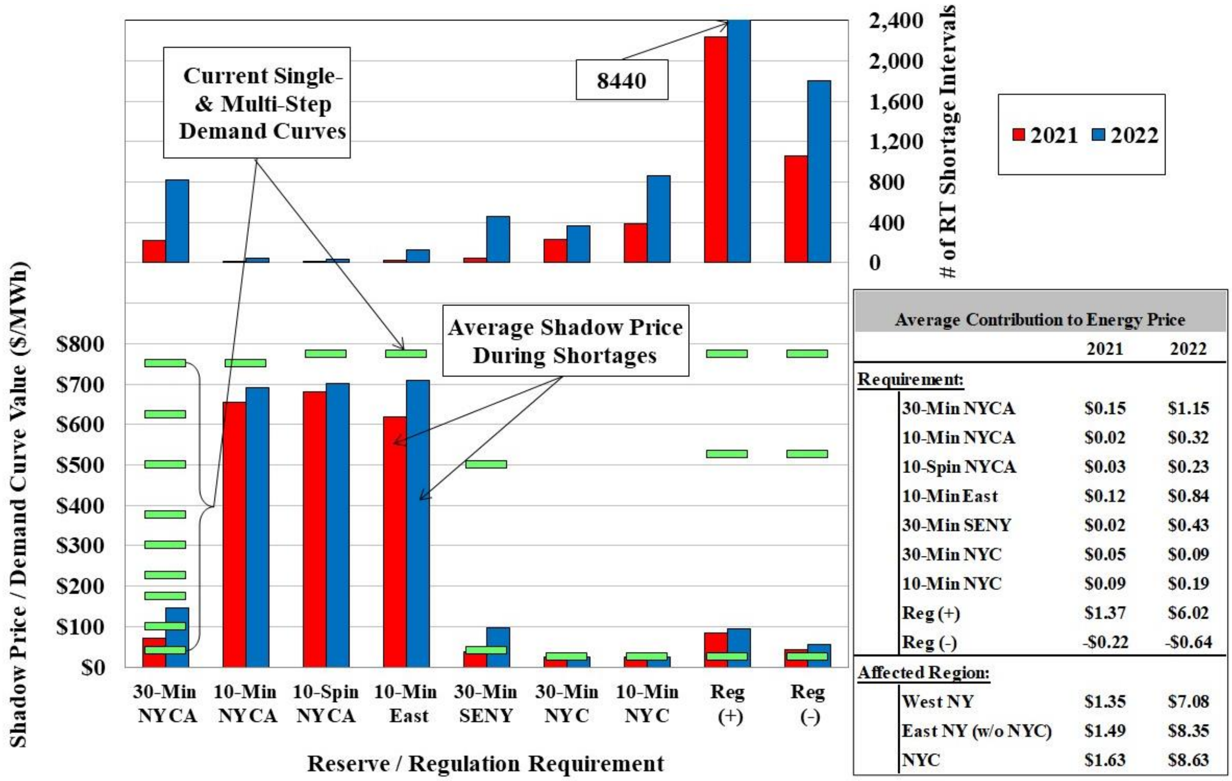
The top portion of the figure shows the frequency of physical shortages. The bottom portion shows the average shadow price during physical shortage intervals and the current demand curve level of the requirement. The table shows the average shadow prices during physical shortages multiplied by the frequency 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.

379 This new multi-step demand curve was effective on July 13, 2021.

- 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-98: Real-Time Prices During Ancillary Services Shortages
2021 – 2022



Average Contribution to Energy Price		2021	2022
Requirement:			
	30-Min NYCA	$0.15	$1.15
	10-Min NYCA	$0.02	$0.32
	10-Spin NYCA	$0.03	$0.23
	10-Min East	$0.12	$0.84
	30-Min SENY	$0.02	$0.43
	30-Min NYC	$0.05	$0.09
	10-Min NYC	$0.09	$0.19
	Reg (+)	$1.37	$6.02
	Reg (-)	-$0.22	-$0.64
Affected Region:			
	West NY	$1.35	$7.08
	East NY (w/o NYC)	$1.49	$8.35
	NYC	$1.63	$8.63

Figure A-99 & Table A-13: Reserves Shortages in New York City

The NYISO currently models two reserves requirements in NYC: [380]

- 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 2022. 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.

380 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.

Table A-13: Real-Time Reserve Shortages in New York City
2022

	RT Reserve Shortages in NYC in 2022		
Month	**# Intervals**	**Avg. Shortage MW**	**#Intervals w/ toNYC Congestion**
Jan	15	54	0
Feb	67	57	0
Mar	49	98	0
Apr	14	61	0
May	112	76	7
Jun	124	129	0
Jul	168	61	3
Aug	434	195	1
Sep	56	34	0
Oct	31	38	3
Nov	42	49	0
Dec	80	158	0
Total	**1192**	**124**	**14**

Figure A-99 illustrates a sample real-time shortage event on August 8, 2022. New York City was short of reserves (either 10-minute or 30-minute or both) primarily in the afternoon hours. For each interval from the beginning of hour 9 to the end of hour 21, the figure shows:

- The amount of reserve shortages (red bar); and
- Net imports from upstate areas (blue bar).[381]

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.

381 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-99: Real-Time Reserve Shortages in New York City
Sample Event on August 8, 2022

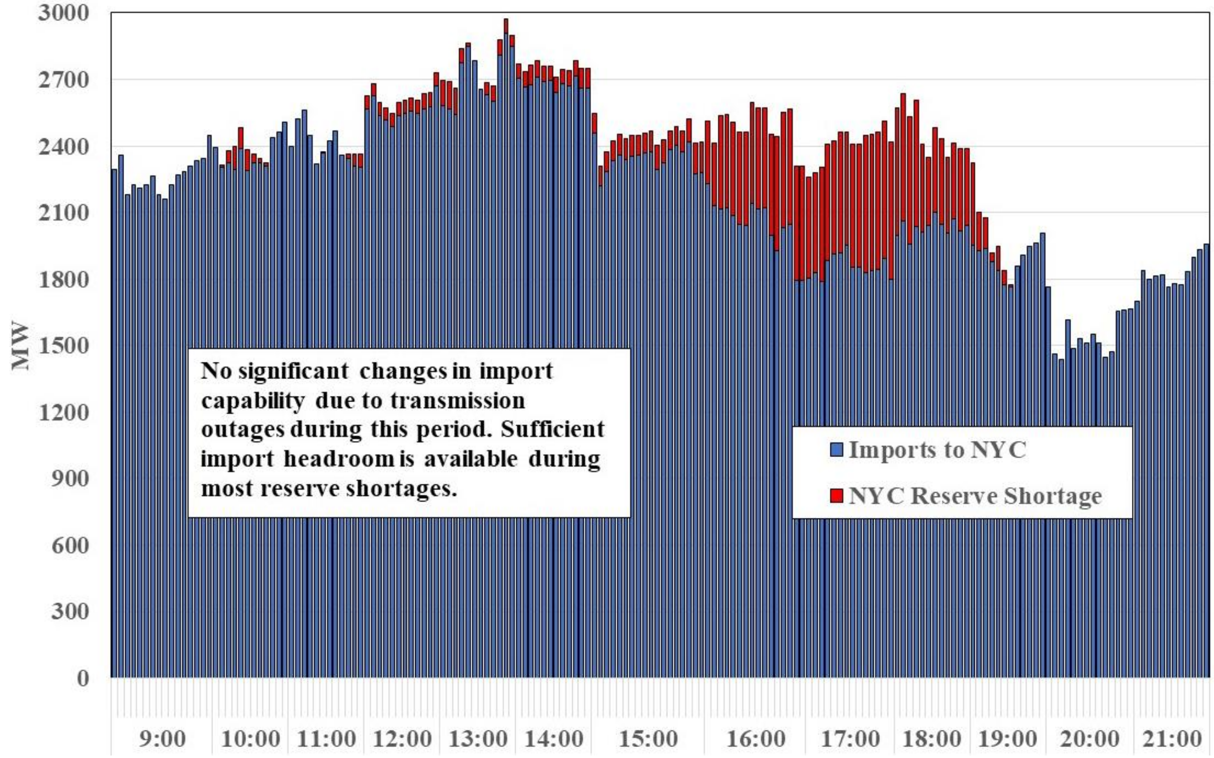


Figure A-100: Comparison of Shortage Pricing in NYISO and Neighboring Markets

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 $3,400/MWh, in addition to reserve shortage prices that reach $1,275/MWh during a 10 minute reserve shortage.[382]

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.

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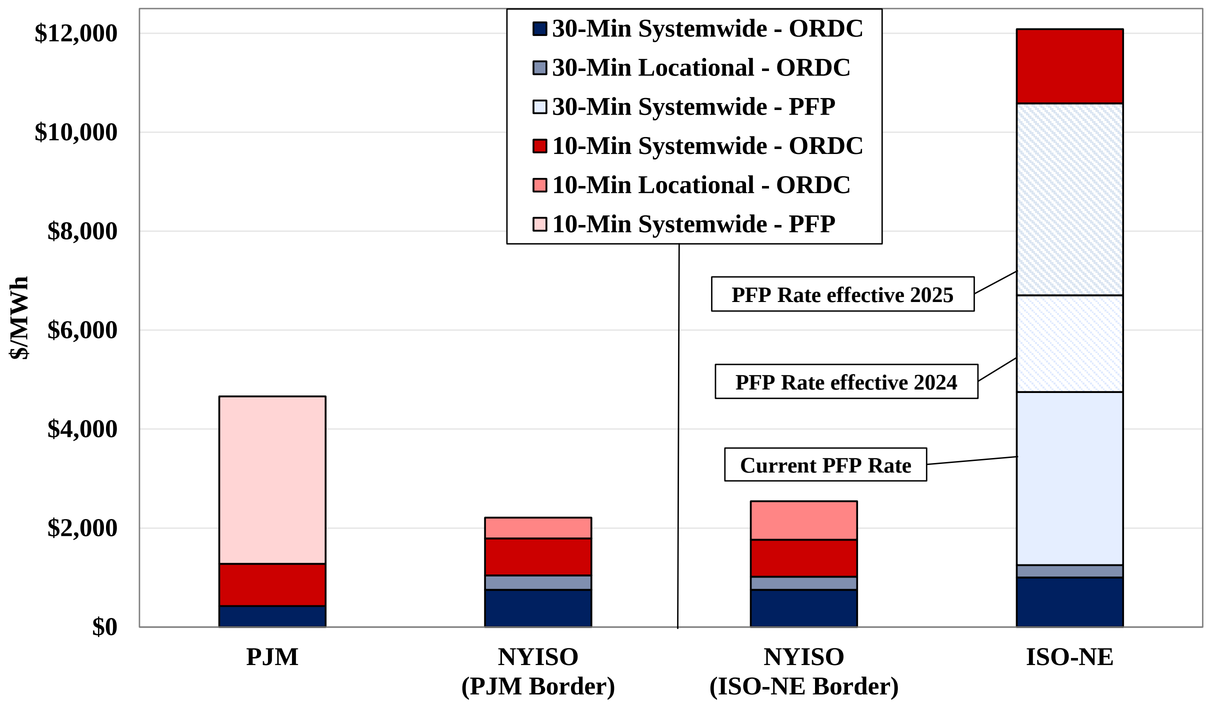
382 FERC previously approved tariff changes that would have increased the shortage price of all PJM reserve products to $2,000/MWh and removed the reserve price cap, then rejected the shortage price increase in a subsequent remand order. PJM filed revised price caps which were accepted by FERC 2022. See September 1, 2022 Order on Compliance in case EL19-58.

Figure A-100 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.[383]

Figure A-100: 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

383 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. PJM ORDC prices reflect the approved $1,275/MWh price cap for 10 minute non-spinning reserve shortages, divided between $850 (10 minute) and $425 (30 minute) prices. A shortage of only 30-minute or 10-minute reserves would result in a price of $850/MWh.

appropriately reflect the acuteness of operating conditions. Efficient prices provide generation and demand response resources incentives to respond to maintain reliability.

The real-time dispatch model ("RTD") manages transmission constraints by redispatching available capacity, which includes online units that can be ramped in five minutes and offline quick-start gas turbines that can be started and brought online within 10 minutes.

If the available physical capacity is not sufficient to resolve a transmission constraint, a Graduated Transmission Demand Curve ("GTDC"), combined with the constraint relaxation (which increases the constraint limit to a level that can be resolved) under certain circumstances, will be used to set prices under shortage conditions. The NYISO first adopted the GTDC approach on February 12, 2016, [384] 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").[385]

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 2022, 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.[386] 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

[384] 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.

[385] These changes are discussed in detail in Commission Docket ER17-1453-000.

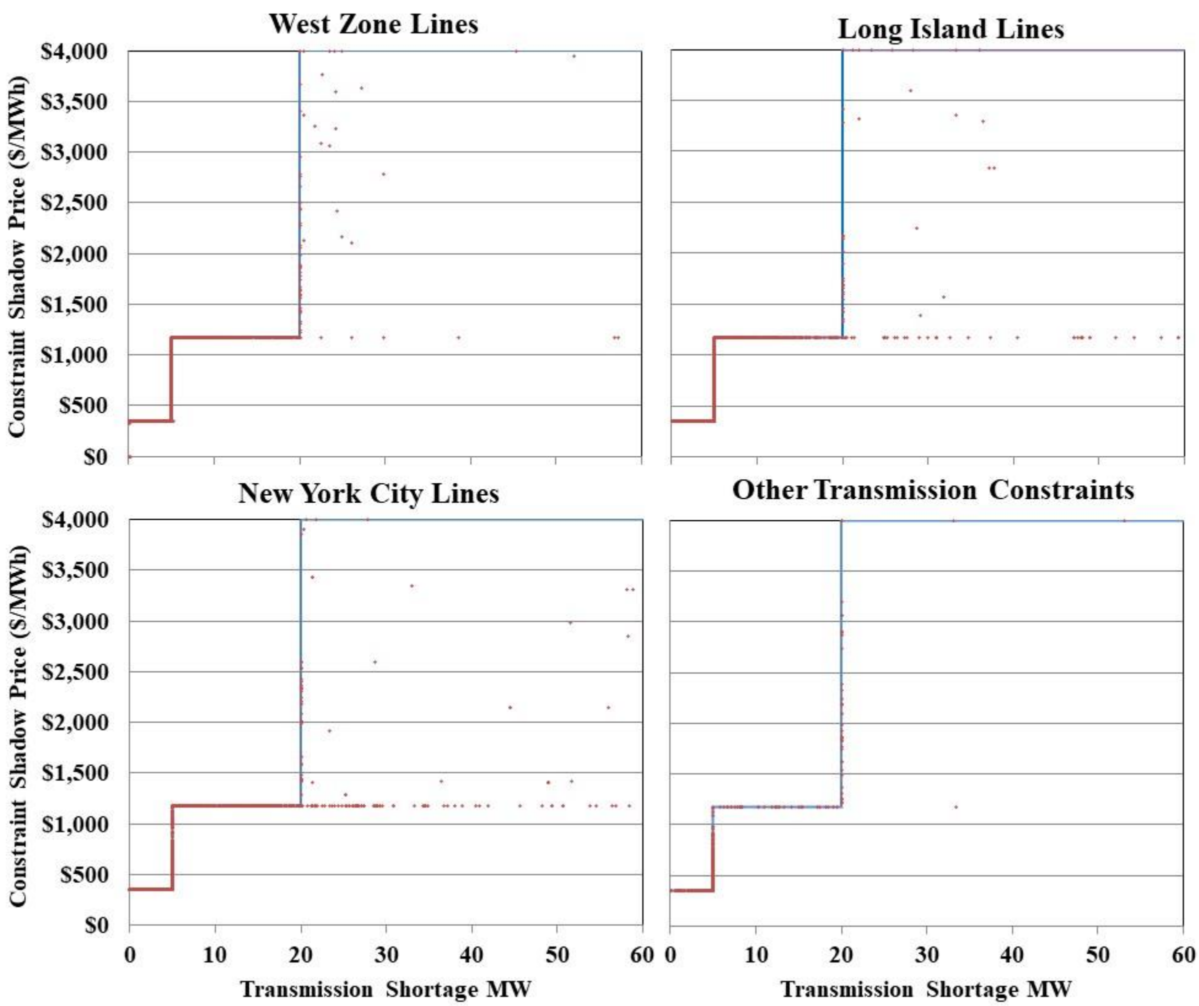
[386] Offline quick-start gas turbine is usually the most expensive available capacity due to their commitment costs, so offline gas turbines are usually not counted towards resolving the constraint unless all available online generation has already been scheduled. If a gas turbine is scheduled by RTD 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.

does not generate as assumed in RTD.[387] This category of shortage is evaluated in this section as well.

Figure A-101, Table A-14 & Figure A-102: Real-Time Congestion Management with GTDC

Figure A-101 examines the use of the GTDC during transmission shortages in the real-time market by constraint group in 2022.

Figure A-101: Real-Time Transmission Shortages with the GTDC
By Transmission Group, 2022



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

In each of the four scatter plots, every point represents a binding transmission constraint during a 5-minute interval, with the amount of transmission shortage (relative to the BMS limit adjusted for the CRM)[388] 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 2022. The table summarizes the following quantities for the transmission constraints grouped by facility voltage class and by location:

- The number of constraint-shortage intervals – This indicates the total number of constraint-shortage intervals in each facility group, including: (a) the average transmission shortage quantity that is recognized in the market model; and (b) additional shortages when removing the congestion-relief effect from offline GTs.
- Average shortage quantity – This includes: (a) the average transmission shortage quantity that is recognized in the market model; and (b) additional shortages when removing the congestion-relief effect from offline GTs.
- Average constraint limit – This indicates the average transmission limit overall all transmission constraints in each facility group.
- Average CRM – This indicates the average CRM MW used in each facility group.
- CRM as a percent of limit – This is the average CRM as a percentage of average limit.

These quantities are summarized over real-time transmission shortage intervals and for transmission constraints that have a 10+ MW CRM.

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 2022. Therefore, Figure A-102 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.

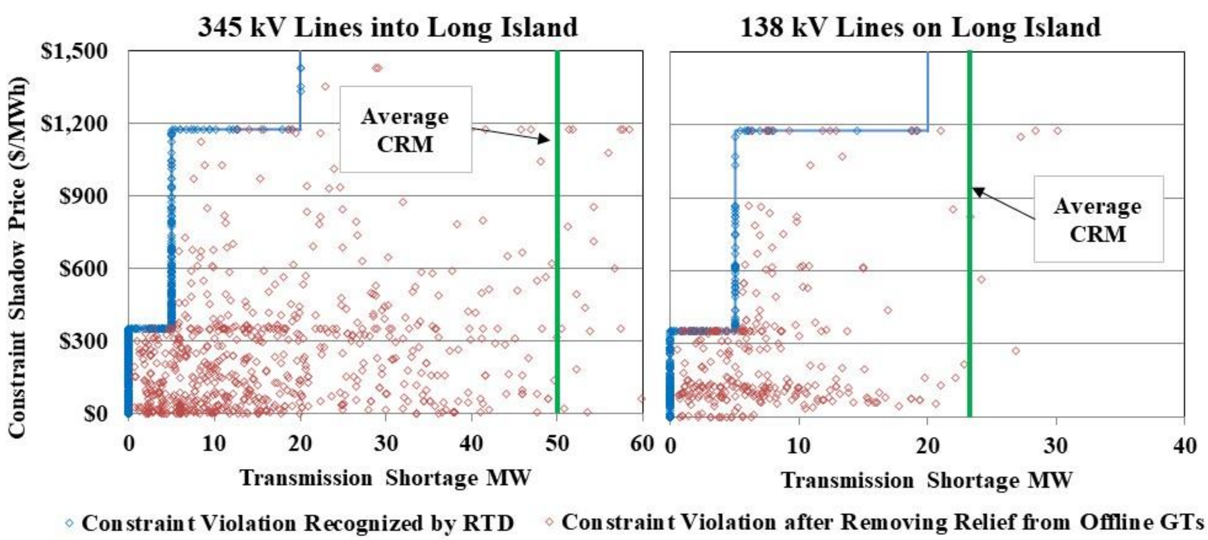
388 BMS limit is the constraint limit that is used in the market dispatch model. For example, if a constraint has a 1000 MW BMS limit and a 20 MW CRM, the shortage quantities reported here are measured against a constraint limit of 980 MW.

Table A-14: Constraint Limit and CRM in New York
During Real-Time Transmission Shortage Intervals, 2022

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	1469	1494	4	4	113	10	9%
115 kV	West	2568	2568	5	5	207	10	5%
	North	946	950	4	4	147	10	7%
	All Others	4131	4140	9	9	213	10	5%
138 kV	New York City	2272	2291	7	7	286	20	7%
	Long Island	1165	1383	6	7	326	23	7%
	All Others	1439	1456	11	12	295	20	7%
230 kV	West	174	177	7	7	691	35	5%
	North	1022	1027	8	8	383	50	13%
	All Others	2292	2326	10	10	535	40	8%
345 kV	New York City	133	146	16	18	776	20	3%
	North	13	14	18	20	2002	50	2%
	Long Island	564	1139	4	19	735	50	7%
	All Others	649	1014	9	13	1404	36	3%

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-102: Transmission Constraint Shadow Prices and Violations
With and Without Relief from Offline GTs, 2022



I. Market Operations and Prices on High Load Days

Despite two heat waves in the summer of 2022 (July 17-24, and August 3-9), load exceeded 30 GW on just two days (i.e., 30.5 GW on July 20, and 30.2 GW on August 8). The NYISO only activated reliability demand response resources (i.e., EDRP/SCRs) for Capital Zone on July 19 and 20 for the needs in the Capital Zone resulted from Greenbush station outages. In addition, NYISO SREed resources for statewide capacity needs and local TOs activated various amounts of utility demand response resources on several days.[389] This subsection evaluates prices under these market conditions.

Figure A-103 & Figure A-104: Market Operations and Prices on High Load Days

Figure A-103 and Figure A-104 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 11 - HB 22) for NYCA:

- Available capacity from non-SRE resources – This includes three categories of unloaded capacity from online units and the capacity of offline peaking units up to the Upper Operating Limit:
  - 30-minute reserves that are scheduled by the market model;
  - 30-minute reserves that are available but are not scheduled by the market model; and
  - Additional capacity that is only available beyond 30 minutes of ramping.
- Schedules from SRE resources – This includes scheduled energy and total 30-minute reserves from SRE resources.
- Constraint shadow prices on the NYCA 30-minute reserve requirement.

In both figures, the solid black lines represent the NYCA 30-minute reserves requirement, adjusted for SCR/EDRP calls when applicable, 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.

389 See presentation "NYISO Summer 2022 Hot Weather Operations" by Aaron Markham at 9/28 MC meeting for more details.

Figure A-103: SRE Commitments and Utility DR Deployment on High Load Days
2022

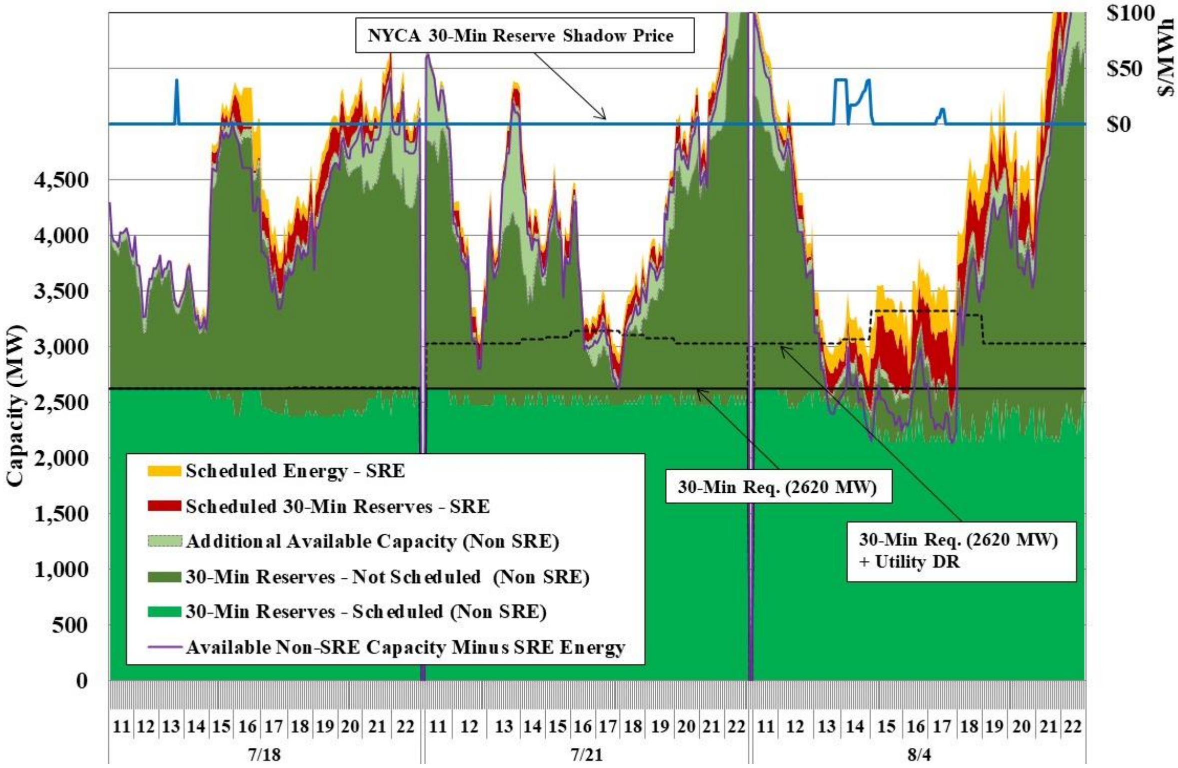
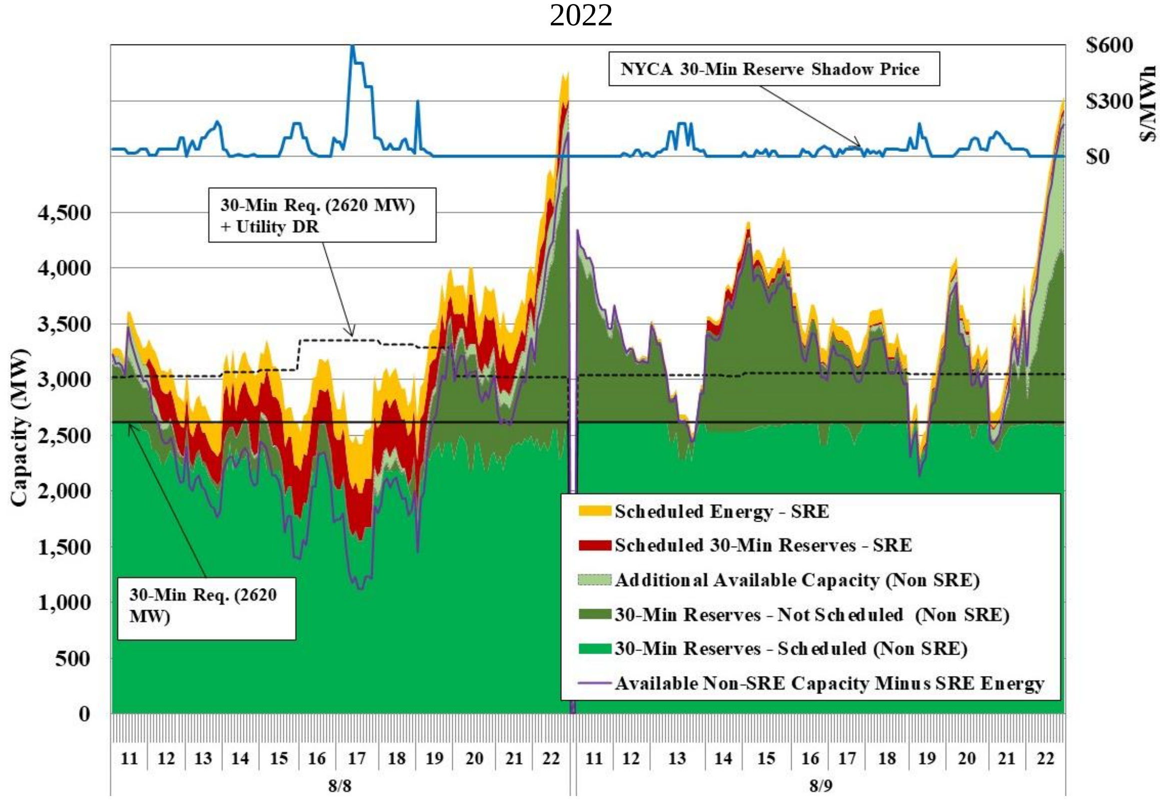


Figure A-104: SRE Commitments and Utility DR Deployment on High Load Days
2022



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-105: 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.

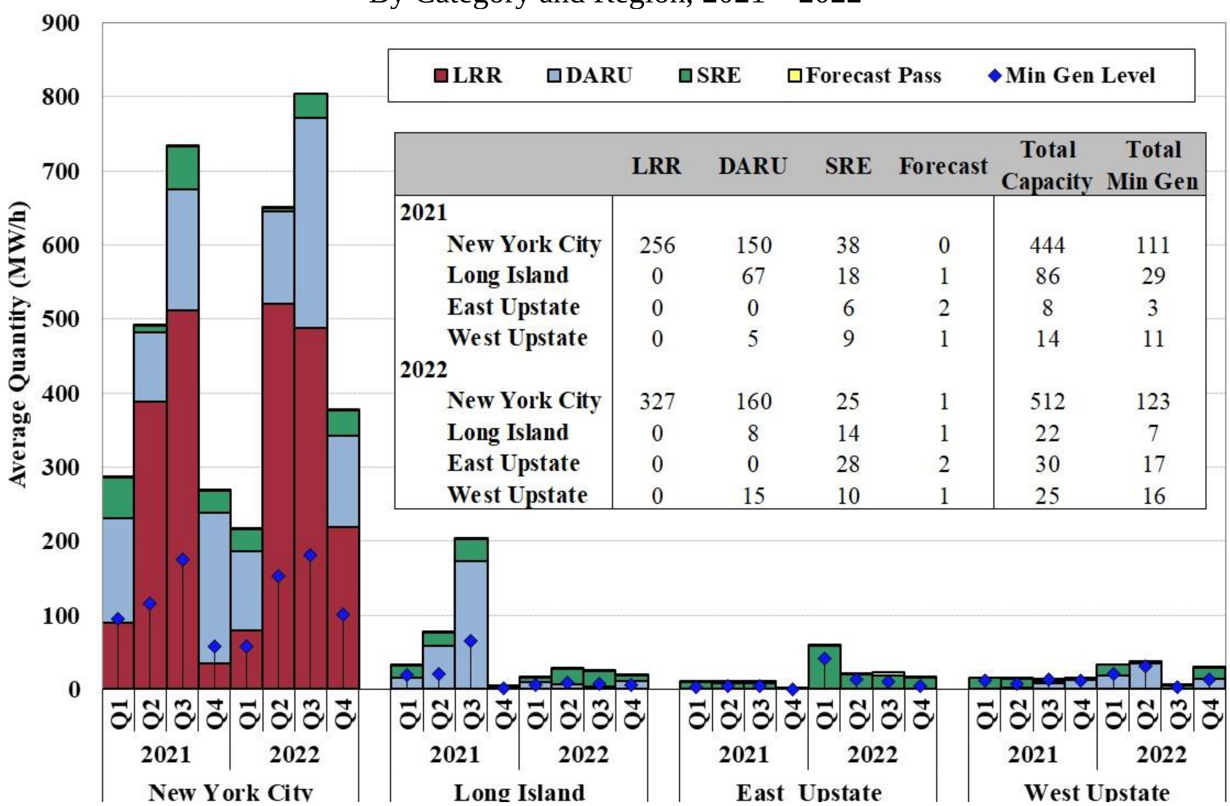
Generators that are committed for reliability are generally not economic at prevailing market prices, but they affect the market by: (a) reducing prices from levels that would otherwise result from a purely economic dispatch; and (b) increasing non-local reliability uplift since a portion of the uplift 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-105 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 2021 and 2022. 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 2021 and 2022 on an annual basis.

Figure A-105: Supplemental Commitment for Reliability in New York
By Category and Region, 2021 – 2022



	LRR	DARU	SRE	Forecast	Total Capacity	Total Min Gen
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
2022						
New York City	327	160	25	1	512	123
Long Island	0	8	14	1	22	7
East Upstate	0	0	28	2	30	17
West Upstate	0	15	10	1	25	16

Figure A-106 & Figure A-107: 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-105). 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 the vast majority of days, it would still be beneficial to reflect the underlying needs through market signals.

Figure A-106 examines Forecast Pass commitments in 2021 and 2022. 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.

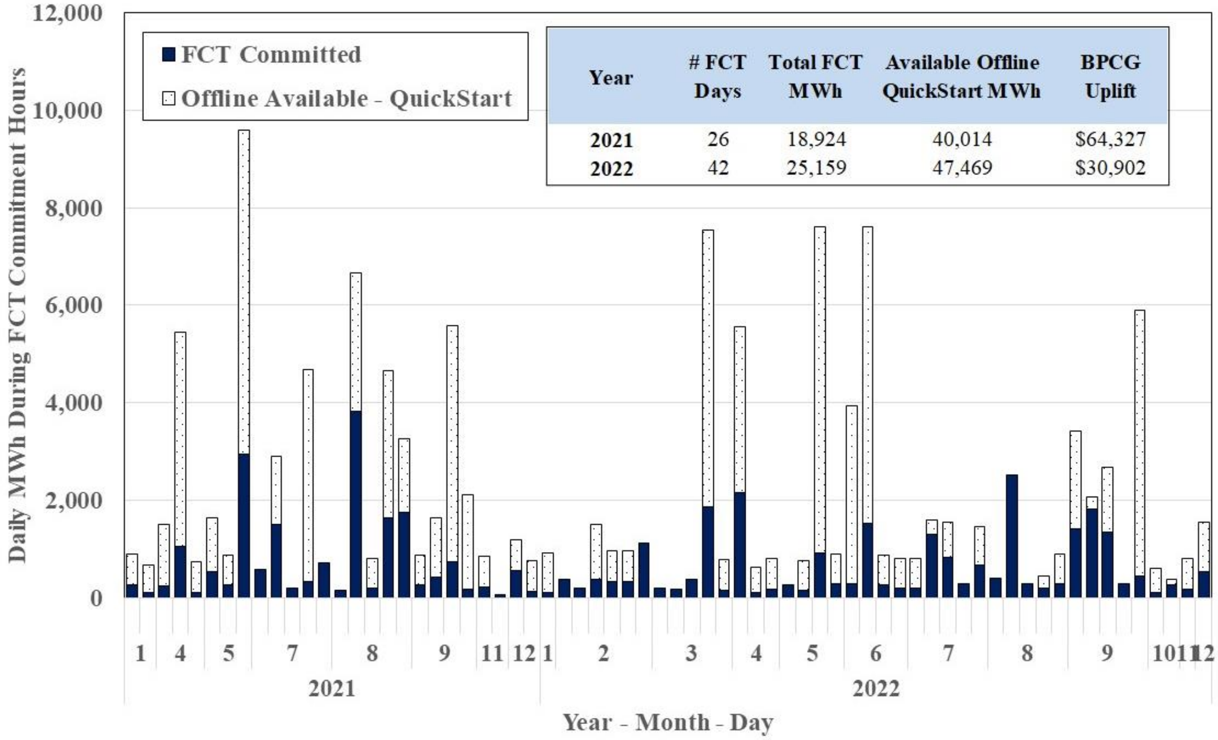
The inset table summarizes for 2021 and 2022:

- 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-107 compares the FCT commitment with forecast physical energy needs in the day-ahead market in 2022, 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-106: Forecast-Pass Commitment
2021-2022



Year	# FCT Days	Total FCT MWh	Available Offline QuickStart MWh	BPCG Uplift
2021	26	18,924	40,014	$64,327
2022	42	25,159	47,469	$30,902

Figure A-107: FCT Commitment and DAM Forecast Physical Energy Needs
By Day, 2022

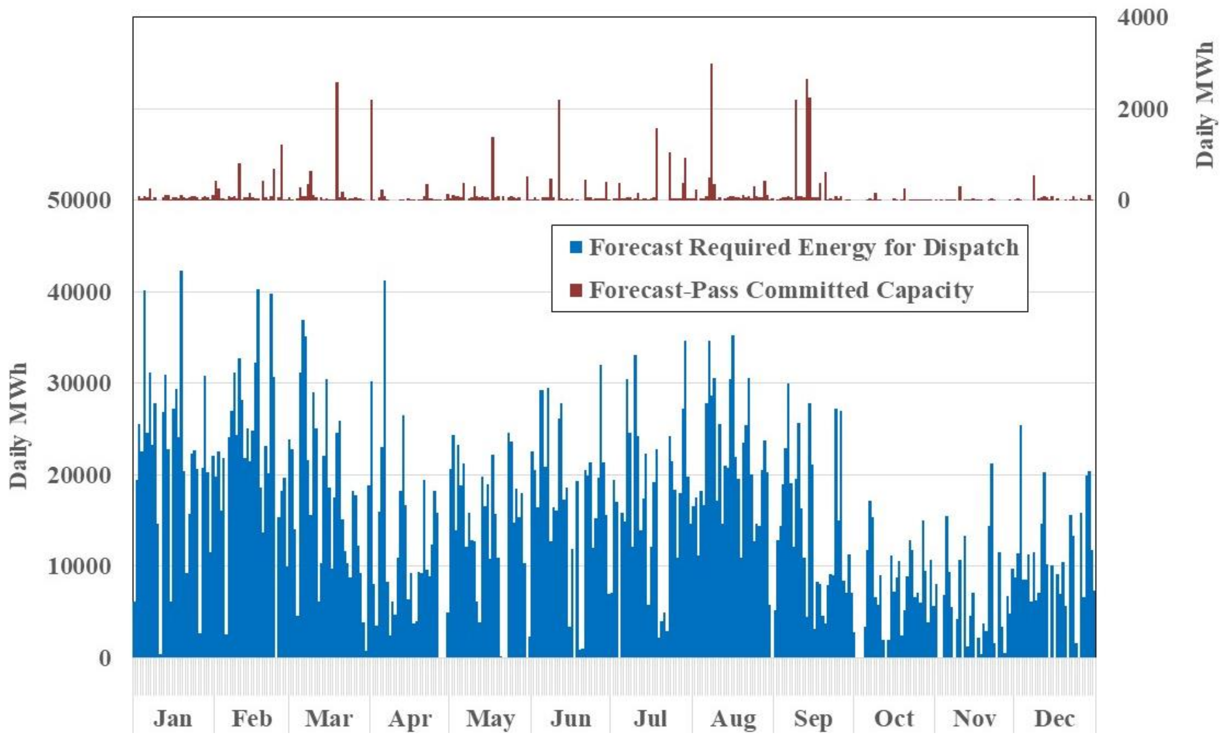


Figure A-108: Supplemental Commitment for Reliability in New York City

Most supplemental commitment for reliability occurred in New York City. Figure A-108 summarizes an analysis that identifies the causes for the reliability commitments in New York City. Specifically, Figure A-108 shows the minimum generation committed for reliability by reliability reason and by location in New York City during 2021 and 2022.

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: [390]

- N-1-1-0 – If needed for one or two of the following reasons:
    - Voltage Support – If needed for 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. Occurs when resources are needed to maintain flows below acceptable levels without shedding load 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.[391]
- NOx Only – If only needed for the NOx bubble requirement. [392] 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.

In Figure A-108, for N-1-1-0 constraints, capacity is shown for the load pocket that was secured:

- ERLP - East River Load Pocket
- AWLP - Astoria West/Queensbridge Load Pocket
- AVLP - Astoria West/ Queens/Vernon Load Pocket
- FRLP - Freshkills Load Pocket
- GSLP - Greenwood/Staten Island Load Pocket; and
- SDLP - Sprainbrook Dunwoodie Load Pocket.

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390 A unit is considered committed for a LRR constraint if it would be violated without the unit's capacity.

391 See *NYSRC Reliability Rules & Compliance Manual*, Version 35, See Section G.2 Local Area Operation: Loss of Gas Supply – New York City, Requirement R1.

392 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.

Figure A-108: Supplemental Commitment for Reliability in New York City
By Category and Region, 2021 – 2022

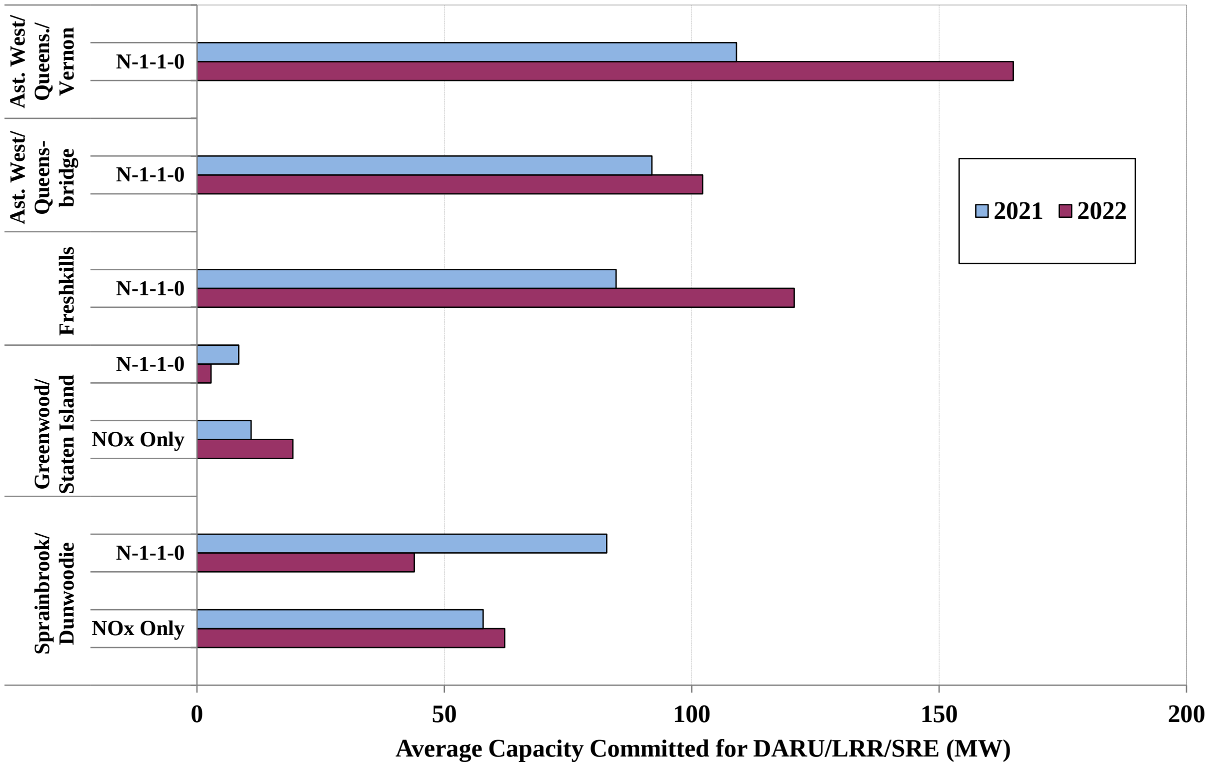


Figure A-109: Excess LRR Commitment in New York City

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-109 shows our evaluation of the necessity during the Ozone season of 2022.

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-109: Excess NOx-Rule LRR Commitment in New York City
Ozone Season, 2022

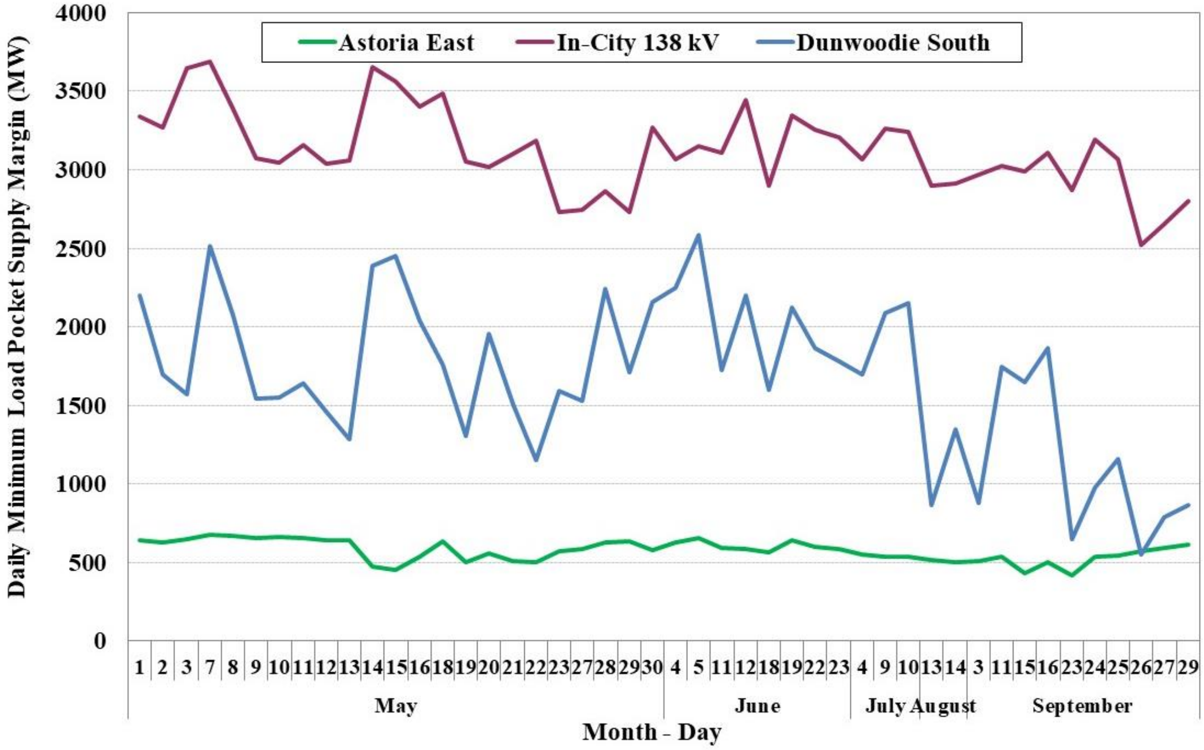


Table A-15: Day-ahead Reserve Price Estimates for Selected NYC Load Pockets

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 2022 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 2022 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
2022

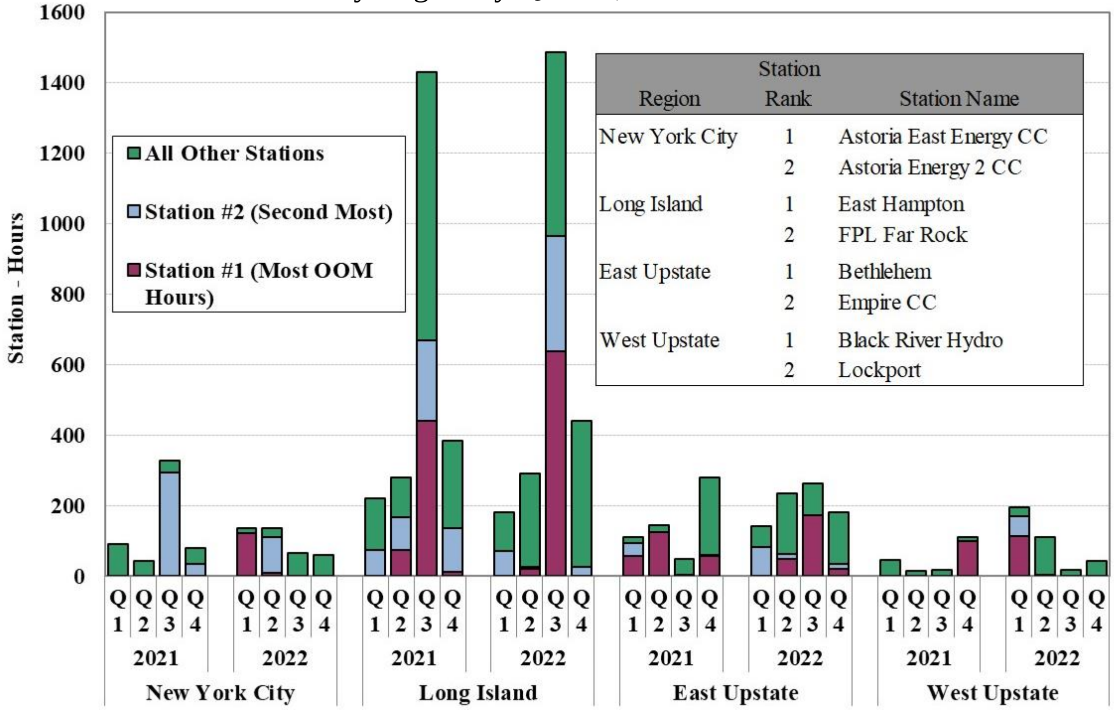
Area	Average Marginal Commitment Cost ($/MWh)
NYC 345 kV System	$3.59
Selected 138 kV Load Pockets:	
Astoria West/Queensbridge	$7.70
Vernon	$5.40
Freshkills	$5.90

Figure A-110: Frequency of Out-of-Merit Dispatch

Figure A-110 summarizes the frequency (i.e., the total station-hours) of OOM actions on a quarterly basis in 2021 and 2022 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 2022 are shown separately from other stations (i.e., "Station #1" is the station with the highest number of OOM hours in that region during 2022, 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-110: Frequency of Out-of-Merit Dispatch
By Region by Quarter, 2021 - 2022



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-111 and Figure A-112 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 local Transmission Owners.

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:

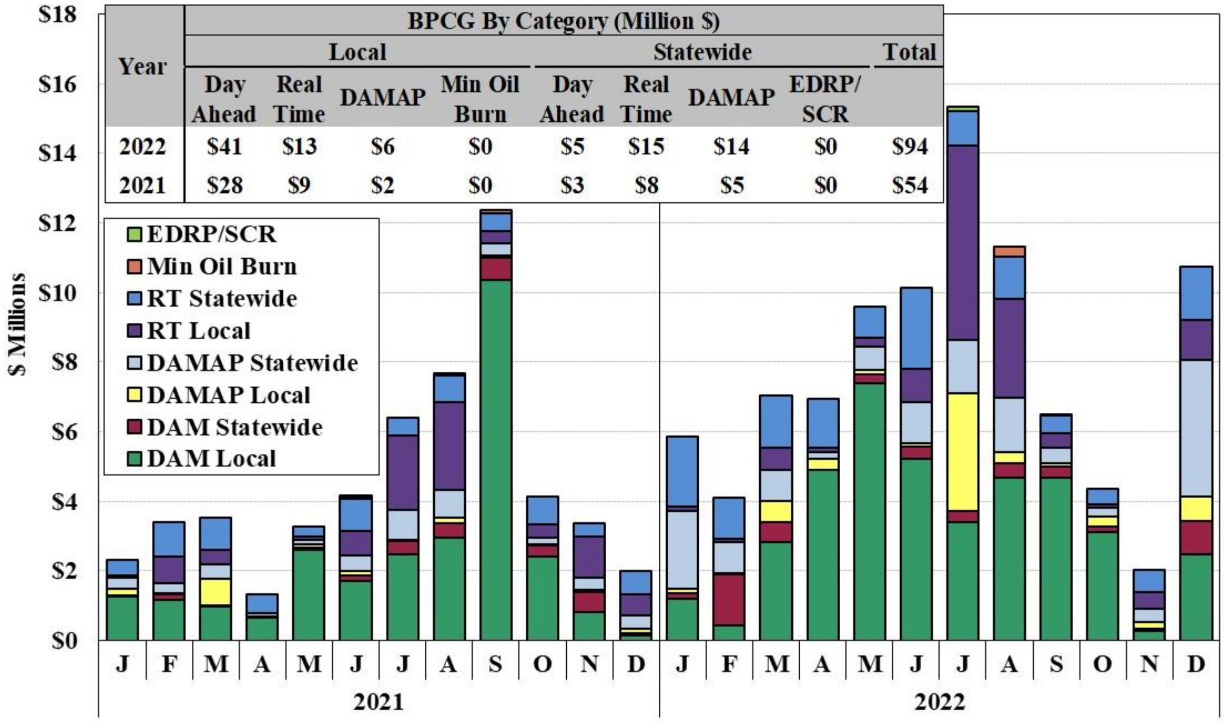
- Day-Ahead Market – Guarantee payments are made to generators committed in the SCUC due to Local Reliability Rule ("LRR") or as Day-Ahead Reliability Units ("DARU") for local reliability needs at the request of local Transmission Owners. Although the uplift from payments to these units is allocated 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-111 & Figure A-112: Uplift Costs from Guarantee Payments

Figure A-111 shows the seven categories of uplift costs associated with guarantee payments on a monthly basis for 2021 and 2022. 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.

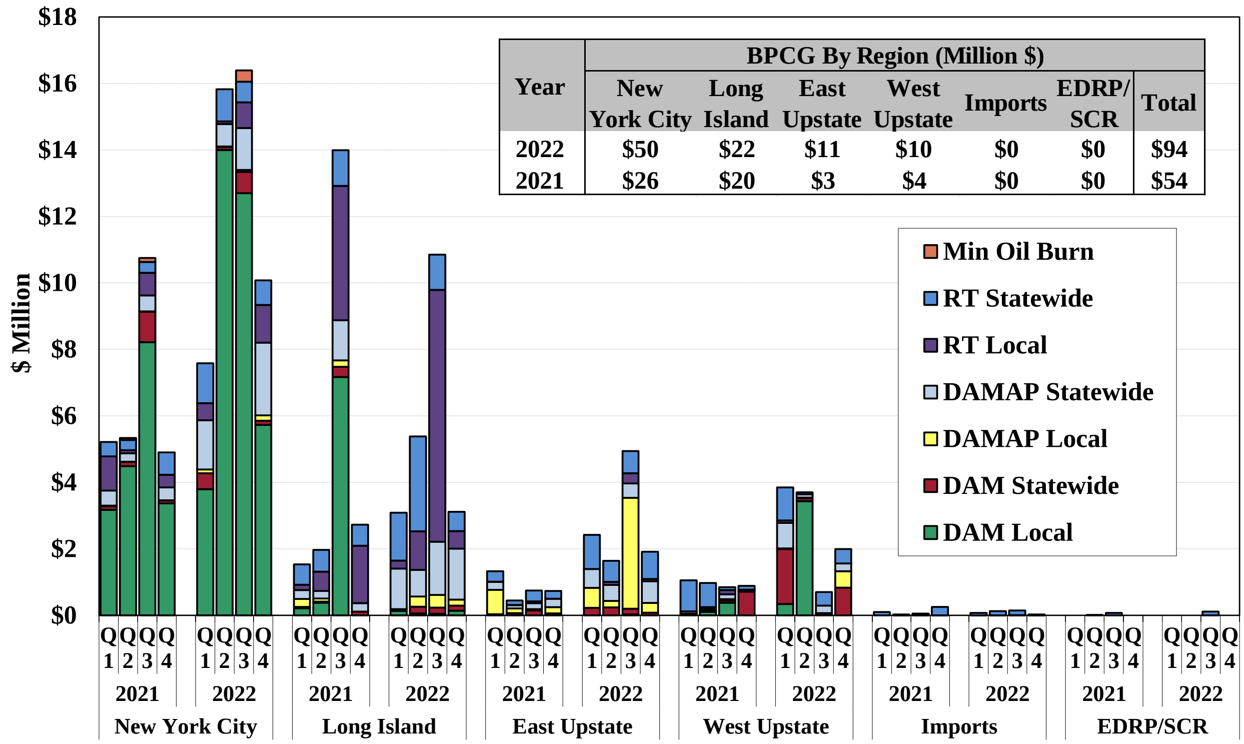
Figure A-112 shows the seven categories of uplift charges on a quarterly basis in 2021 and 2022 for four regions in New York: (a) West Upstate, which includes Zones A through E; (b) East Upstate, which includes Zones F through I; (c) New York City, which is Zone J; and (d) Long Island, which is Zone K. The uplift costs paid to import transactions from neighboring control areas and EDRP/SCR resources are shown separately from the generation resources in these four regions in the chart. The table summarizes the total uplift costs in each region on an annual basis for these two years.

Figure A-111: Uplift Costs from Guarantee Payments by Month
2021 – 2022



Year	BPCG By Category (Million $)								
	Local				Statewide				Total
	Day Ahead	Real Time	DAMAP	Min Oil Burn	Day Ahead	Real Time	DAMAP	EDRP/ SCR	
2022	$41	$13	$6	$0	$5	$15	$14	$0	$94
2021	$28	$9	$2	$0	$3	$8	$5	$0	$54

Figure A-112: Uplift Costs from Guarantee Payments by Region
2021 – 2022



Year	BPCG By Region (Million $)						
	New York City	Long Island	East Upstate	West Upstate	Imports	EDRP/ SCR	Total
2022	$50	$22	$11	$10	$0	$0	$94
2021	$26	$20	$3	$4	$0	$0	$54

It is also noted that Figure A-111 and Figure A-112 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.

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)

- $$\sum_{i \in LP^k, i \neq LG} (GenMW_i + Res10MW_i + Res30MW_i + Res60MW_i) \geq Load\ Forecast - Total\ NORM + Line\ 1\ NORM \quad (3.2)$$

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-113, 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-113: Illustrative Diagram of the example system

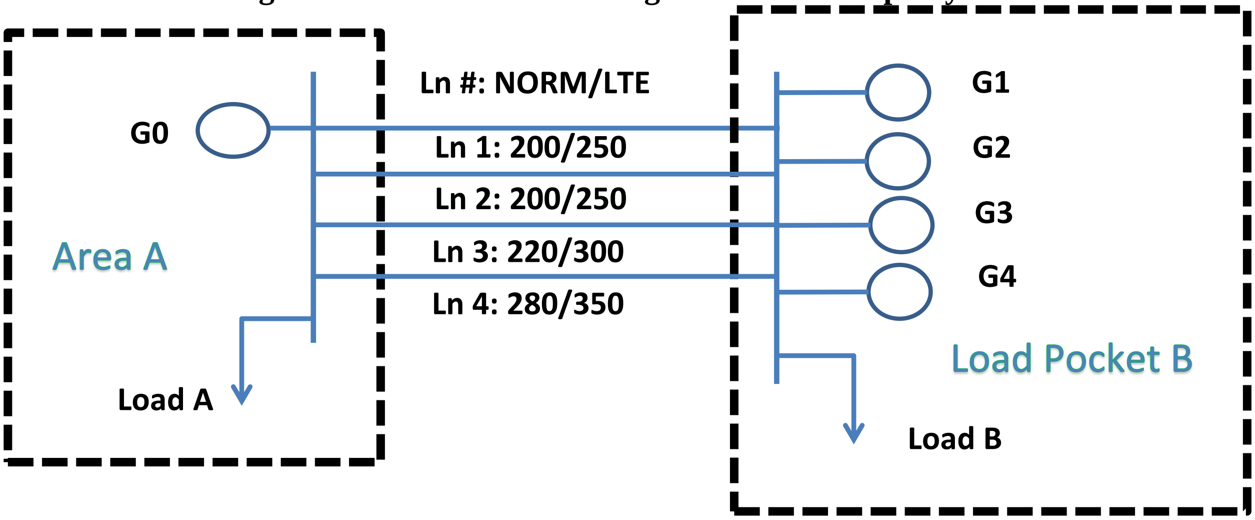


Table A-16 lists assumed physical parameters for the five generators in the example system. G0 represents the aggregation of less expensive generation in Area A, while G1 represents a slow-moving ST in the load pocket, which is also the largest generator in the pocket. G2 and G3 represent two CCs, and 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.[393] 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 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:

[393] See *NYISO Transmission and Dispatching Operations Manual*, Section 2.3.2.

- $\sum_i \left(SF_i^k * Gen_i \right) \leq Limit_{N-1}^k$ (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.[394] 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.[395]

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.[396] The amount of UCAP purchased is determined by the intersection of UCAP supply offers in the spot auction and the demand curve (adjusted for capacity sales through bilateral contracts and forward auctions).

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394 The ICAP requirement = (1 + IRM) * Forecasted Peak Load. The IRM was set at 19.6 percent in the most recent Capability Year (i.e., the period from May 2022 to April 2023). NYSRC's annual IRM reports may be found at "http://www.nysrc.org/NYSRC_NYCA_ICR_Reports.html".

395 The locational ICAP requirement = LCR * Forecasted Peak Load for the location. The Long Island LCR was 102.9 percent from May 2021 to April 2022 and 99.5 percent from May 2022 to April 2023. The New York City LCR was 80.3 percent from May 2021 to April 2022 and 81.2 percent from May 2022 to April 2023. The LCR for the G-J Locality was set at 87.6 percent from May 2021 to April 2022 and 89.2 percent from May 2022 to April 2023. These are set in the annual Locational Minimum Installed Capacity Requirements Study, which may be found here.

396 The capacity demand curves are not used in the forward strip auction and the forward monthly auction. The clearing prices in these two forward auctions are determined based on participants' offers and bids.

Hence, the spot auction purchases more capacity than is necessary to satisfy the UCAP requirement when more capacity is available.

The demand curve for a capacity market Locality is defined as a straight line through the following two points:[397]

- Net CONE at Level of Excess – 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".
- $0 at Zero Crossing Point – 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);
- Analyses of the efficiency of the capacity market design, including the correlation of monthly spot prices with reliability value over the year (sub-section E) and zonal spot prices with reliability value in each region (sub-section F);

397 The demand curves also have maximum price levels which apply when UCAP procured falls substantially below the UCAP requirement. The demand curves for the 2021/22 and 2022/2023 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.

- Need for Financial Capacity Transfer Rights ("FCTRs") to incentivize merchant transmission projects (sub-section G); and

- Methods for assessing marginal capacity value by resource category (sub-section H).

A. Installed Capacity of Generators in NYCA

Figure A-114 - Figure A-115: 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-114 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 2013 through 2023.[398, 399] The top panel of Figure A-114 shows the amount of capacity that entered or exited the market during each year.[400] Generator retirements in the coming years will include units that plan to operate as winter-only resources.

Figure A-115 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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398 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.

399 In this report, we have reconstituted the historic coincident and non-coincident peak demand values in both Figure A-114 and Figure A-115 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.

400 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-114: Installed Summer Capacity of Generation by Prime Mover
2013 – 2023

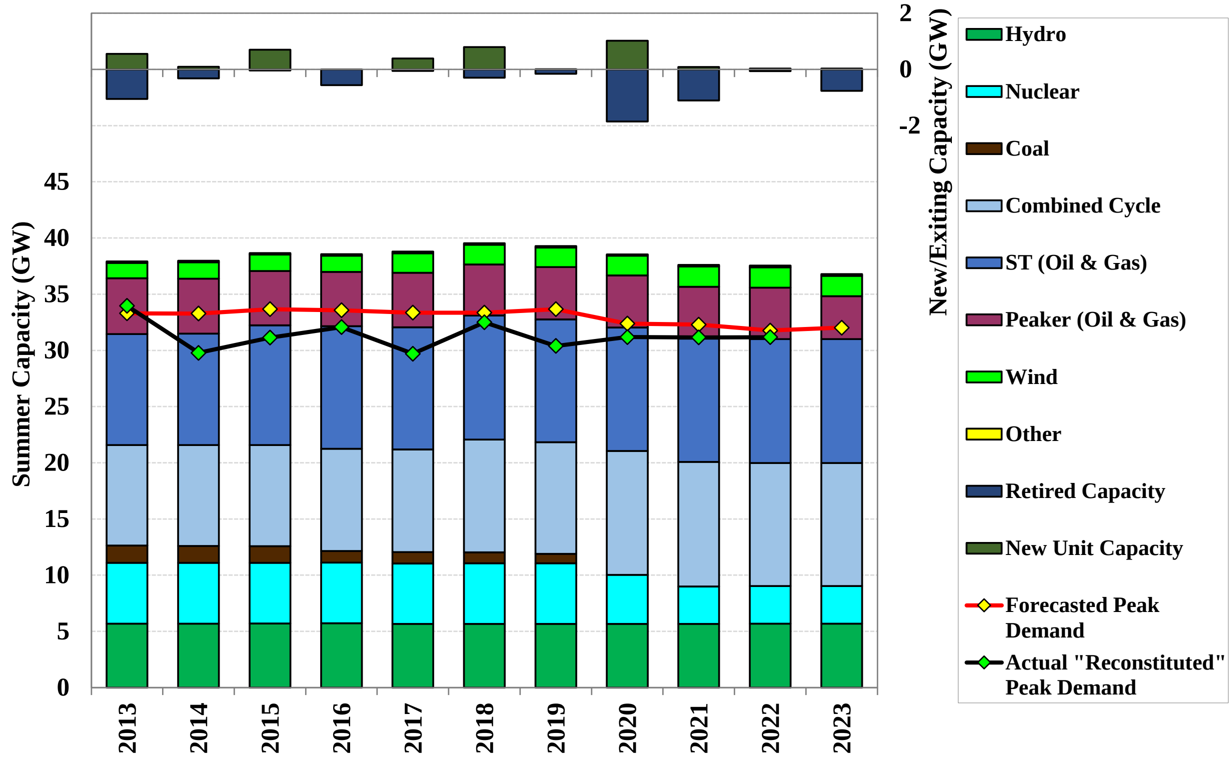
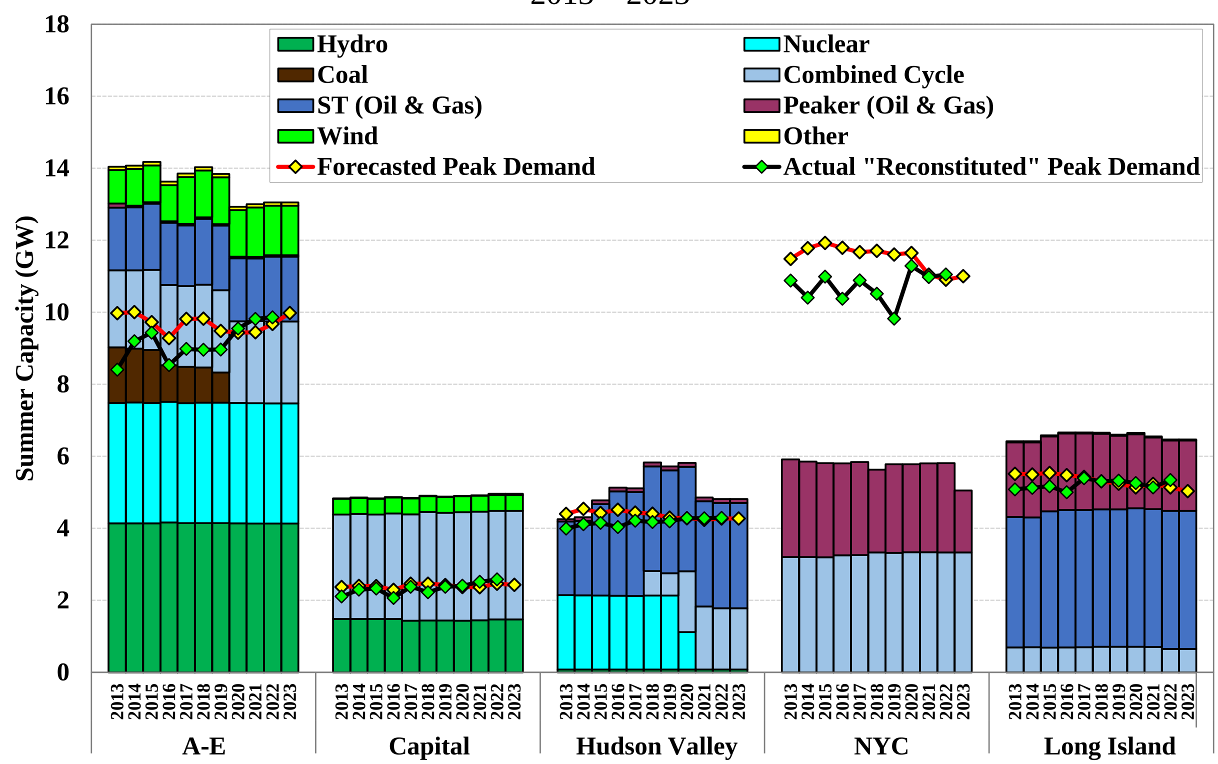


Figure A-115: Installed Summer Capacity of Generation by Region and by Prime Mover
2013 – 2023



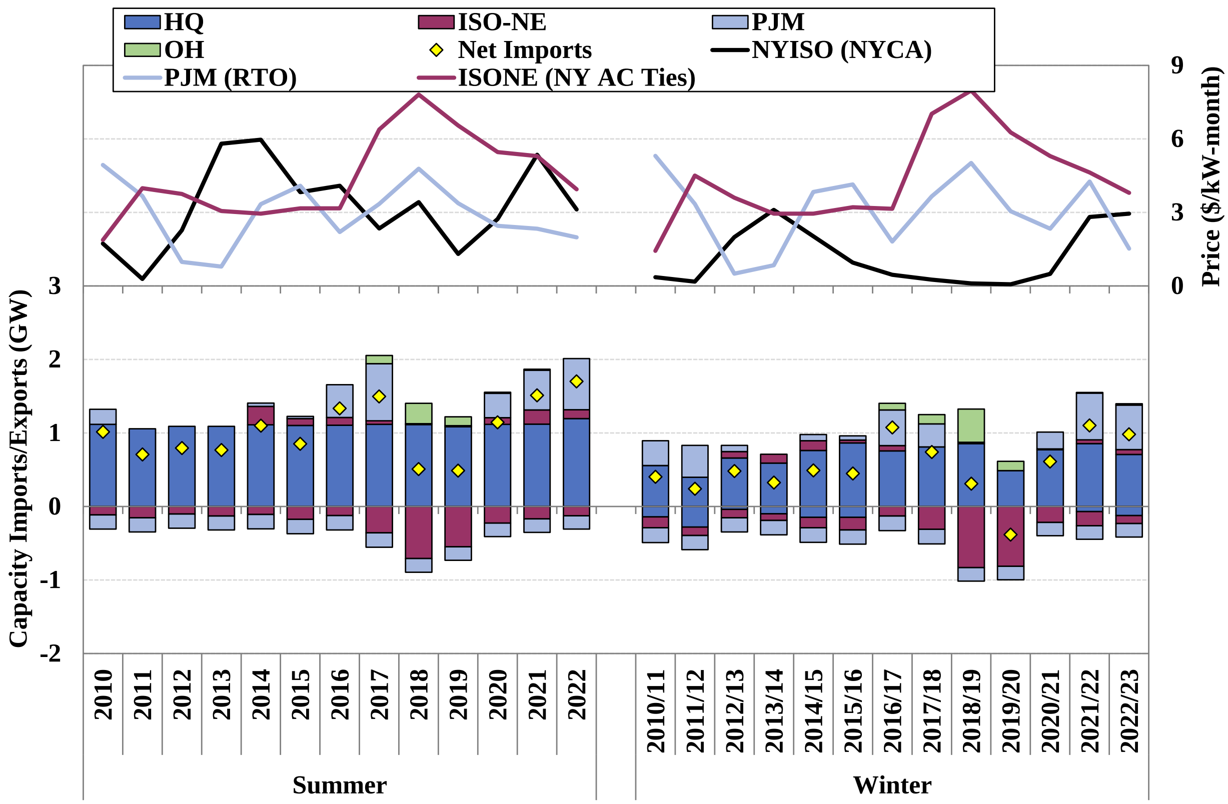
B. Capacity Imports and Exports

Figure A-116: 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 pricing outcomes of each auction.

Figure A-116 shows the monthly average of net capacity imports into the NYISO from neighboring control areas from Winter 2010/11 through Winter 2022/23 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.[401] 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-116: NYISO Capacity Imports and Exports by Interface
Winter 2010/11 – Winter 2022/23



401 The values for Winter 2022/23, reflect average net imports and average prices through February 2023.

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.[402] This gives suppliers an 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 two most recent like-Capability Period average EFORd values of resources in the Locality in accordance with Section 4.5 of the NYISO's Installed Capacity Manual.[403]

Table A-20: Historic Derating Factors by Locality

Table A-20 shows the derating factors the NYISO calculated for each capacity zone from Summer 2018 onwards. Derating factors tend to be highest in regions with the most intermittent capacity and most volatile year-over-year in regions with older generation fleets.

Table A-20: Derating Factors by Locality

Summer 2018 – Winter 2022/23

Locality	Summer 2022	Summer 2021	Summer 2020	Summer 2019	Summer 2018	Winter 2022/23	Winter 2021/22	Winter 2020/21	Winter 2019/20	Winter 2018/19
G-I	7.63%	5.45%	5.77%	7.15%	4.92%	10.39%	8.41%	3.21%	6.87%	6.45%
LI	6.27%	4.91%	6.91%	6.47%	6.28%	10.31%	7.21%	5.91%	7.96%	6.90%
NYC	3.26%	2.69%	3.51%	4.09%	7.09%	3.41%	2.48%	2.70%	4.42%	5.98%
A-F	14.20%	13.27%	11.78%	12.50%	11.15%	10.70%	11.36%	9.63%	10.26%	8.93%
NYCA	9.78%	8.77%	8.30%	8.79%	8.56%	8.91%	8.40%	6.61%	8.00%	7.57%

Figure A-117: 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.

402 The variables and methodology used to calculate EFORd for a resource can be found here.

403 The Derating Factor used in each six-month capability period for each Locality may be found here.

Figure A-117 presents the distribution of EFORds of natural gas and oil-fired units based on technology type and age designation.[404] 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-117: EFORd of Gas and Oil-fired Generation by Age

Summer – Five-Year Average

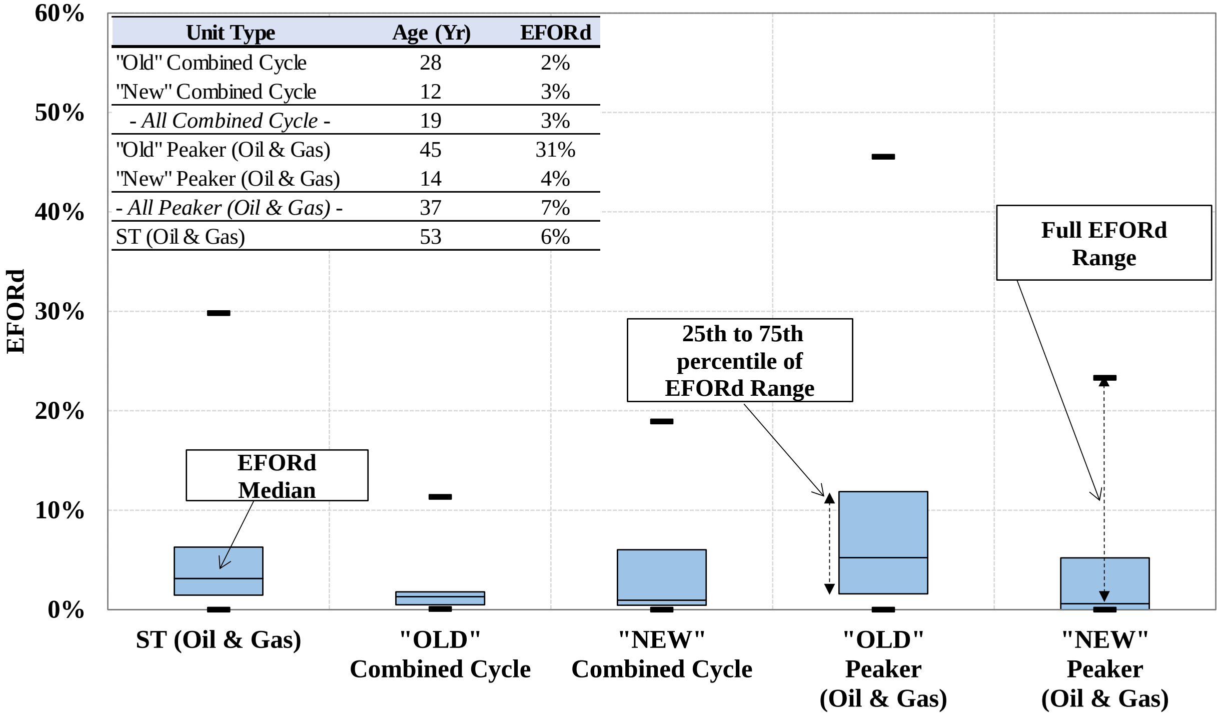


Figure A-118: Unavailable Capacity to RTC & RTD from Various Technologies on Highest Load Days

The NYISO tariff utilizes a DMNC testing process to determine the ICAP ratings for traditional generators such as nuclear units, combined cycles, steam turbines, and peaking facilities.[405] The process is very similar in most ways across these unit, but takes into consideration certain technology-specific characteristics in fine tuning testing obligations.[406] 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 temperatures, and a seasonal peak temperature rating

404 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."

405 Section 5.12.1.2 of the Tariff establishes the DMNC test obligation on generators.

406 See Section 4.2 of the ICAP Manual.

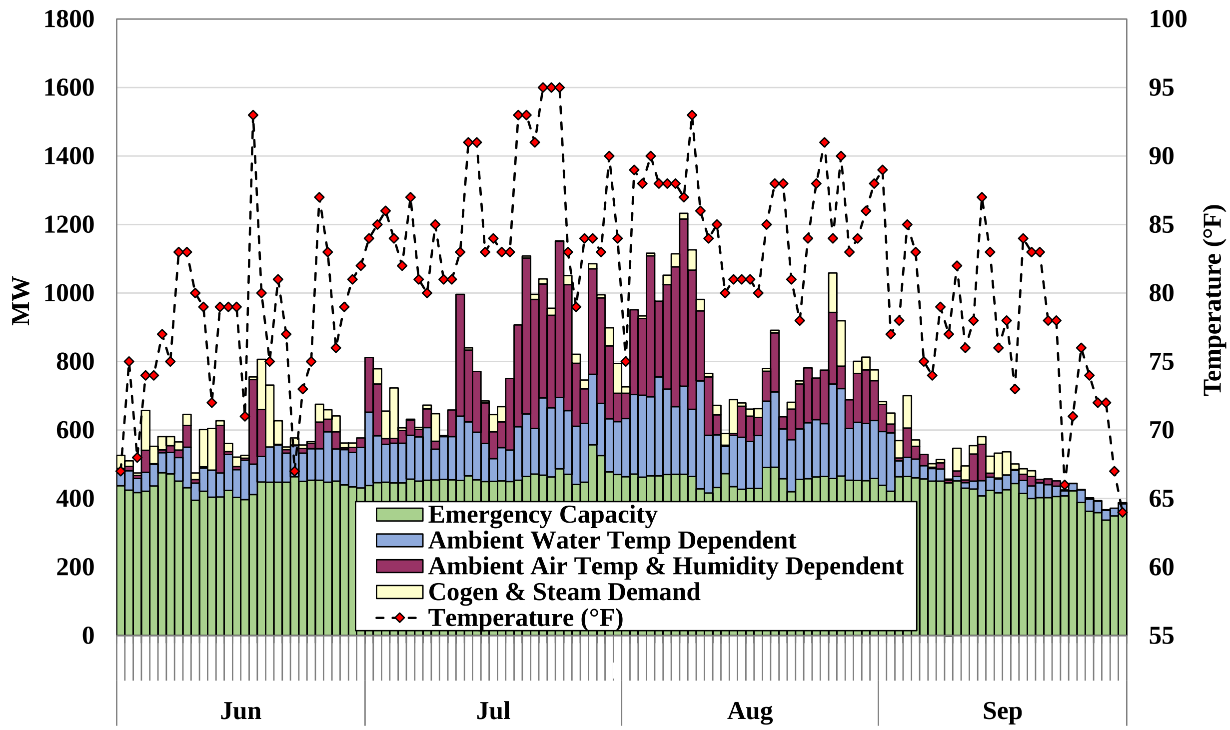
determined by the previous Transmission District peak conditions across the most recent four like-Capability Periods. Functionally, this tends to mean that the ICAP ratings for these unit types during the summer Capability Periods are lower than the value at which they test at since tests are often done at cooler temperatures than the seasonal peak.

The data in Figure A-118 below shows an analysis the average amount of capacity the was unavailable to the market from nuclear and fossil generators during hours 10-19 of each day from June 1 through September 30, 2022, due to the following reasons:

- Emergency Capacity – Capacity offered above a generator's normal upper operating limit ("UOLn") that is only activated under NYISO Emergency Operations.[407]
- Ambient Water Temp Dependent – The value of the derated capacity at certain generators that indicated less availability due to higher water temperatures.
- Ambient Air Temp & Humidity Dependent – The value of capacity derated or failing to achieve UOL due to limitations imposed by ambient air temperatures and/or relative humidity conditions.
- Cogen & Steam Demand – The reported derates from cogeneration units due to limitations associated with their host steam demand.

Figure A-118: Capacity Shortfall from Inadequate Accreditation for Ambient Conditions

Summer 2022



407 See NYISO Emergency Operations Manual.

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. The DMNC test process should be enhanced to better assign seasonal ratings to ambient conditions dependent generators based on the trio of ambient factors that impact nuclear and fossil generation's daily capability. Additionally, cogeneration resources ought to be seasonally rated in a similar manner to Behind the Meter Net Generation ("BTM:NG") resources taking into account host steam demand during the peak.

D. Capacity Market Results

Figure A-119 – Figure A-122: Capacity Sales and Prices

Figure A-119 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.[408] 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, the figure shows sales from external capacity resources into NYCA and exports of internal capacity to other control areas. The upper portion of the figure shows clearing prices in the monthly spot auctions for NYCA (i.e., the Rest of State).

The capacity sales and requirements in the figure 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, the figure also shows the forecasted peak load and the ICAP requirements.

Figure A-120 to Figure A-122 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-119 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.

408 Special Case Resources ("SCRs") are Demand Side Resources whose Load is capable of being interrupted upon demand, and/or Demand Side Resources that have a Local Generator, which is not visible to the ISO's Market Information System and is rated 100 kW or higher, that can be operated to reduce Load from the NYS Transmission System and/or the distribution system at the direction of the NYISO.

Figure A-119: UCAP Sales and Prices in NYCA
May 2021 to February 2023

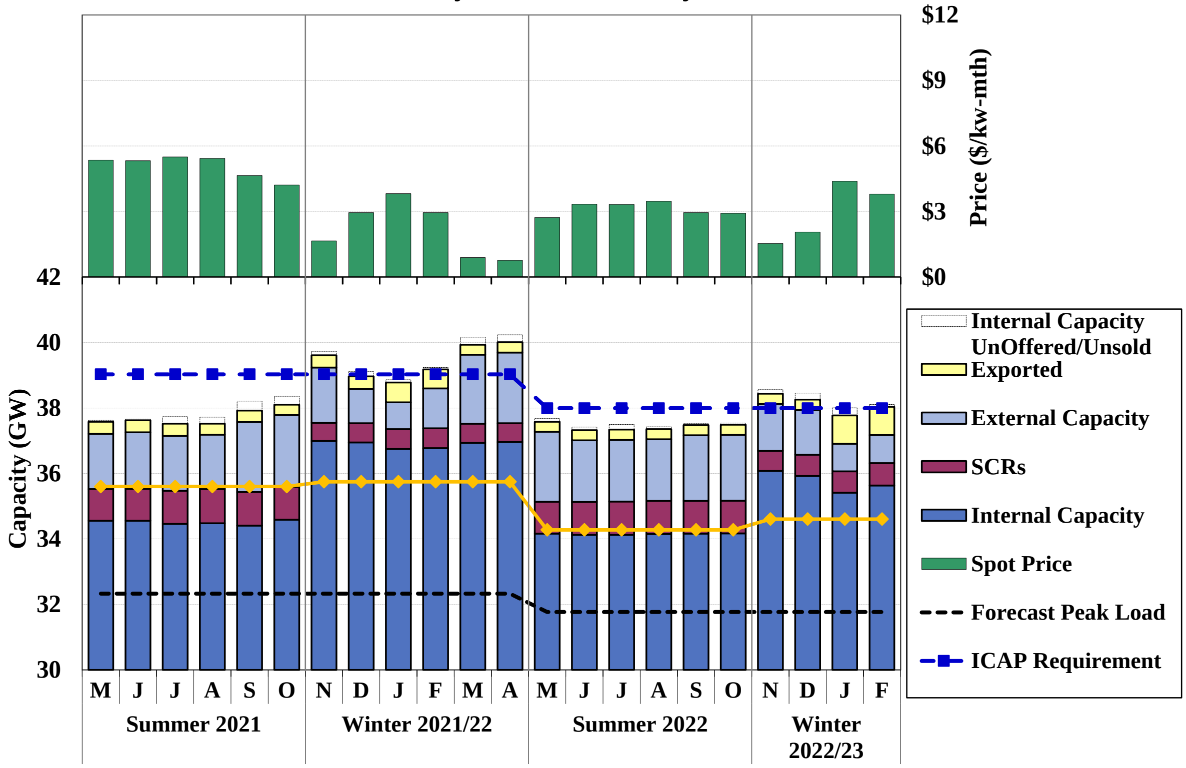


Figure A-120: UCAP Sales and Prices in New York City
May 2021 to February 2023

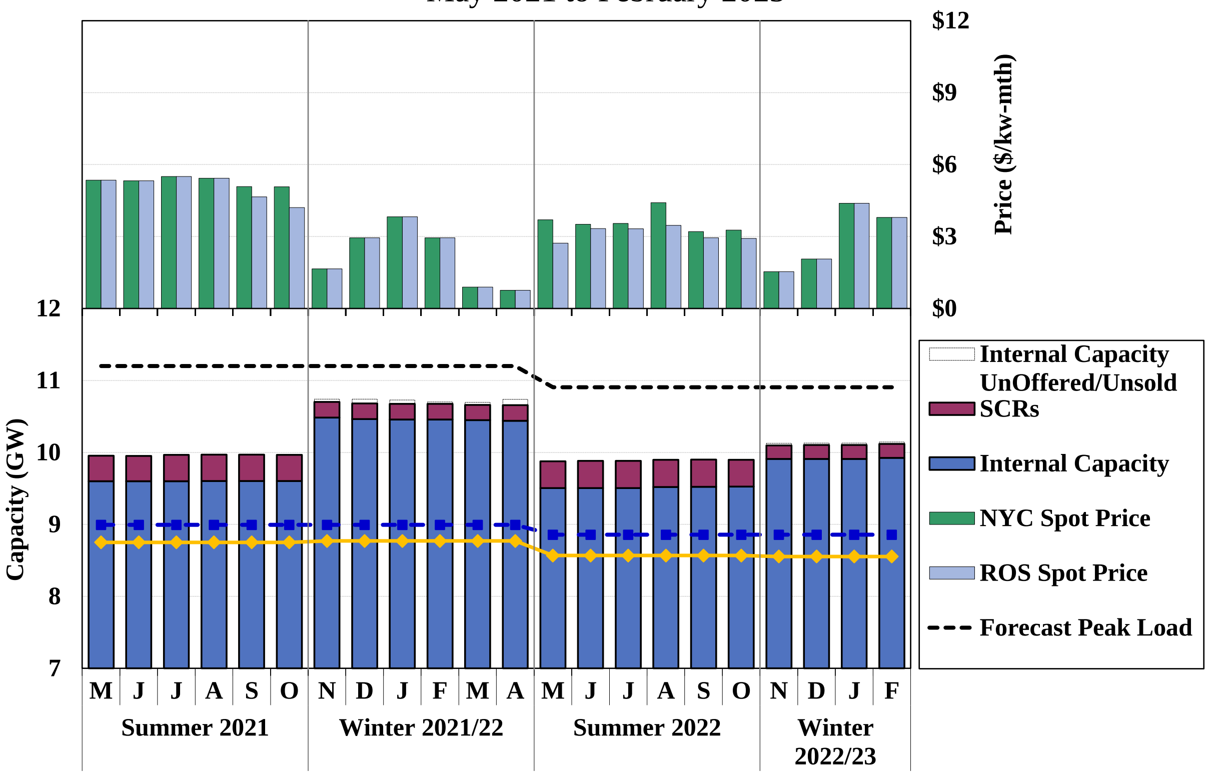


Figure A-121: UCAP Sales and Prices in Long Island
May 2021 to February 2023

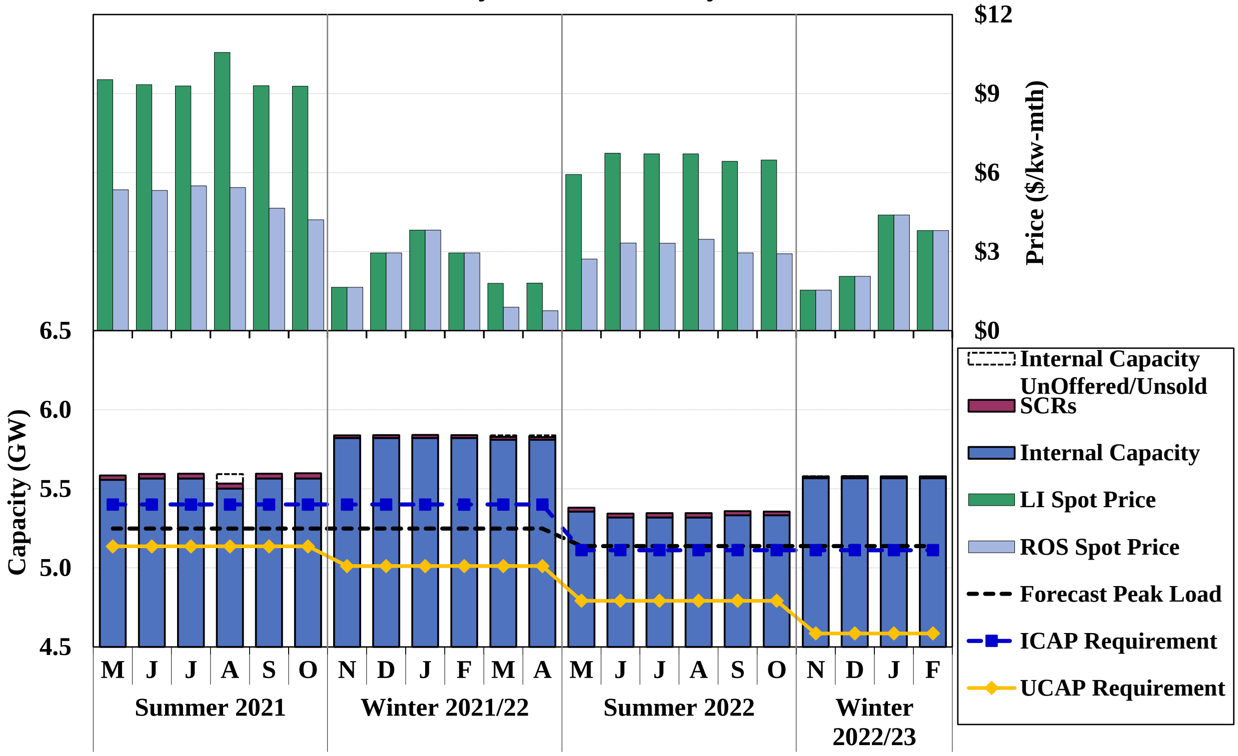


Figure A-122: UCAP Sales and Prices in the G-J Locality
May 2021 to February 2023

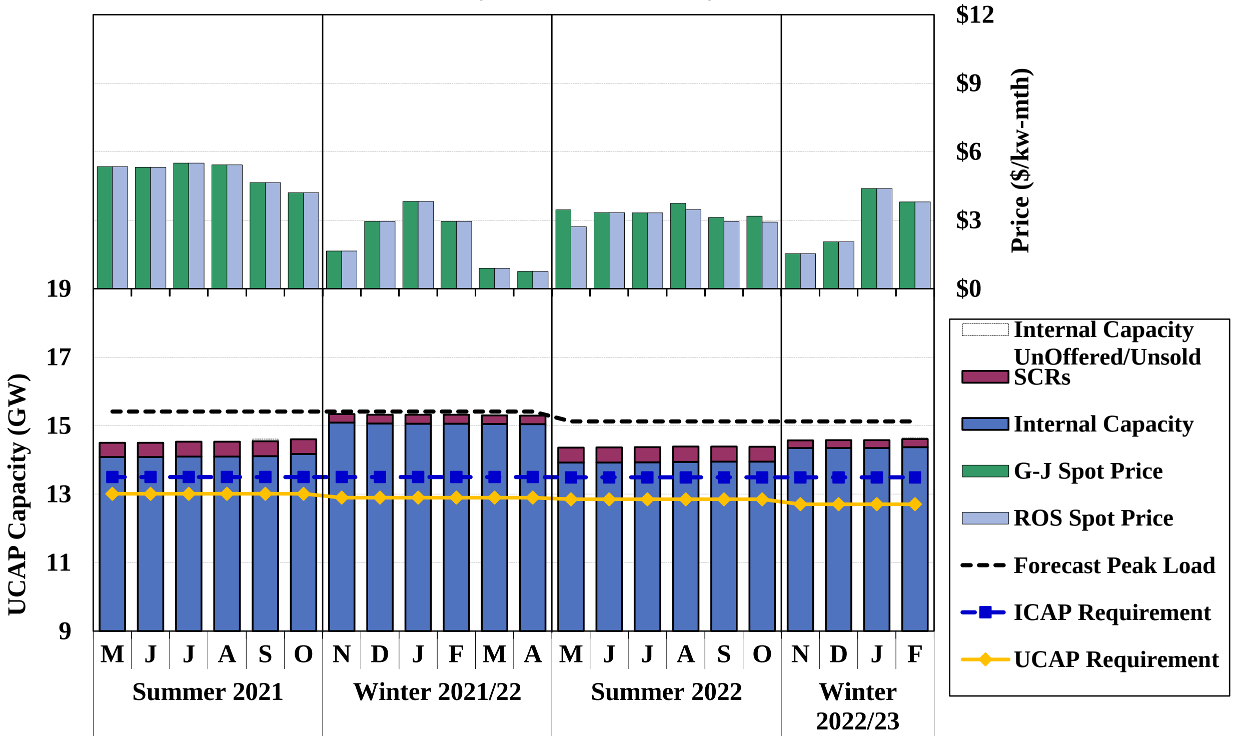
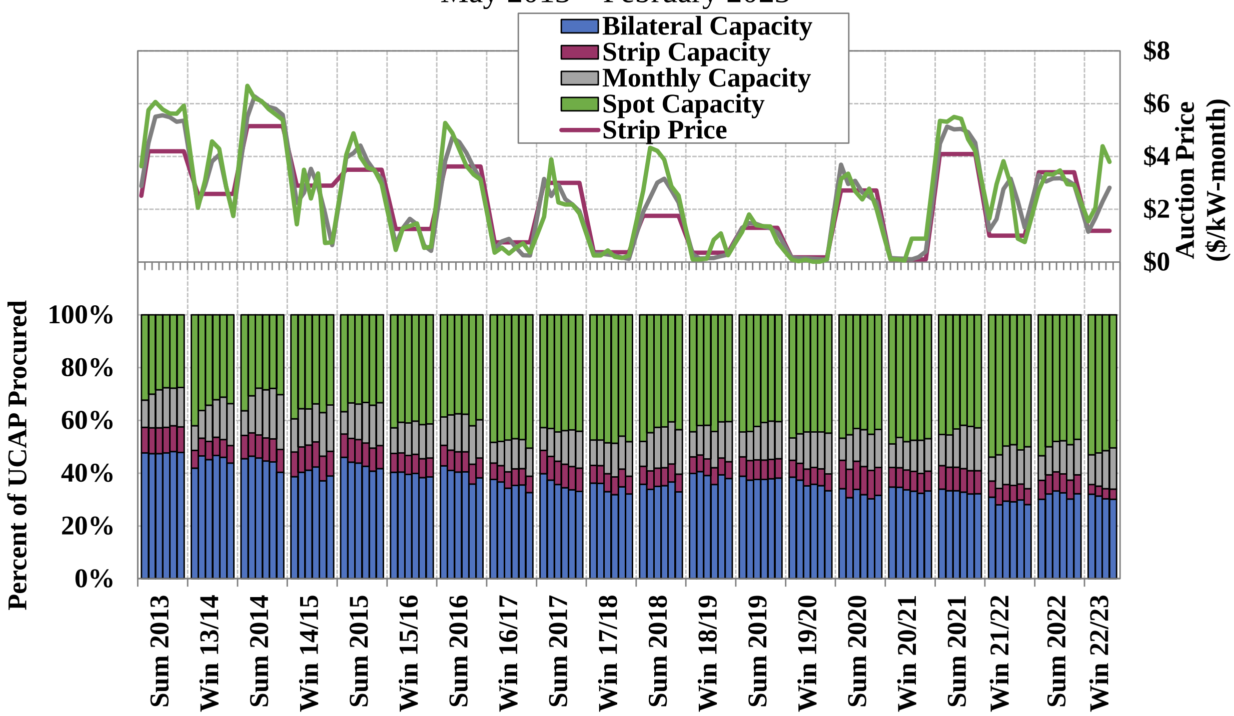


Figure A-123: Capacity Procurement by Type and Auction Price Differentials

Figure A-123 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 2013 capability period on a dollar-per-kilowatt-month basis.

Figure A-123: Auction Procurement and Price Differentials in NYCA

May 2013 – February 2023



E. Analysis of Seasonal Demand Curve Proposal

The capacity market is divided into Summer and Winter Capability Periods of six months each. Currently, summer and winter months use the same ICAP demand curves and capacity requirements set based on peak summer conditions. The price at the requirement (the "reference point") is set so that the demand curve reference unit recovers its Net Cost of New Entry (Net CONE) when surplus capacity is equal to the tariff-prescribed level of excess ("LOE"). The formula to determine the reference point also considers the ratio of winter to summer ICAP in the market ("winter-summer ratio" or "WSR"), which causes prices to be lower in winter than summer when the system is at the LOE. We raise concerns with this construct in Section VIII.I.

In February 2023, NYISO proposed to change the calculation of the seasonal demand curve reference points.[409] The proposal would set separate summer and winter reference points proportionally to the reliability risk in each season in NYISO's resource adequacy model. The proposal includes a minimum guardrail (proposed as an initial 35 percent minimum in each season to be subject to future updates) for the proportion of the demand curve unit's annual reference value allocated to each season's reference point, so that suppliers have an incentive to supply capacity in all months.[410] The proposal makes further changes to the reference point calculation so that the capacity market continues to provide sufficient revenue to the demand curve unit in the event that the WSR is below 1.0.

NYISO's reference point proposal will better signal the seasonal value of capacity if it is paired with timely changes to resource adequacy modeling allowing for accurate detection of winter reliability risks (see Section VIII.I). However, because both seasons will continue to have the same requirements and prices will be determined based on the ICAP WSR, the updated demand curves will be volatile and inefficient under some conditions. These effects can be offset by employing a conservative ceiling on the portion of the demand curve unit's annual revenue requirement that can be allocated to each season, as NYISO has proposed to do initially. However, this approach limits the ability of the demand curves to provide accurate signals when reliability risk is highly concentrated in one season. Hence, we recommend that NYISO move to a seasonal capacity market framework (Recommendation 2022-2). The charts below show potential outcomes under NYISO's proposal.

Figure A-124 and Figure A-125 show seasonal demand curves for the NYC and NYCA capacity zones under NYISO's proposal, based on 2022/23 demand curves and winter-summer ratios. Seasonal demand curves are shown for varying proportions of LOLE risk in the summer. Each graph also shows the currently effective year-round demand curve ("reference") as well as the summer Level of Excess ("SLOE") and LOE plus winter-summer ratio ("WLOE"). The charts demonstrate that changes in the share of seasonal reliability risk can cause dramatic changes in the steepness of the demand curves, especially in winter, because of requirement for the winter demand curve to pass through the WLOE at the targeted winter price level.

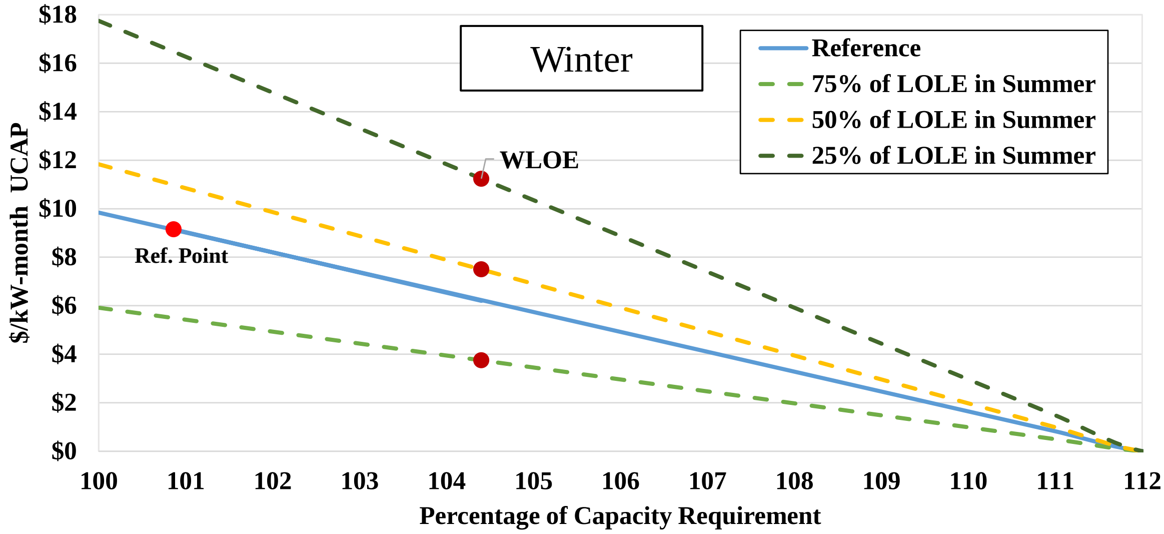
Figure A-126 shows annual revenues to the demand curve reference technology in New York City at various levels of market surplus, based on the seasonal demand curves shown in the previous graphs. Annual revenue is calculated based on the price when summer surplus is equal to the level indicated on the x-axis and winter surplus is equal to that level plus the WSR. Each set of curves provides the demand curve technology revenue equal to its Net CONE when the system is at the SLOE in summer and WLOE in winter. However, revenue varies significantly at other levels of surplus depending on the share of reliability risk taking place in summer or winter. For example, at a surplus of 10 percent above the capacity requirement, annual revenue to the demand curve unit is \$70.30 per kW-year under the status quo 2022/23 demand curves, \$77.60 under NYISO's proposal with 75% of reliability risk in summer, \$55.60 with 50% of reliability risk in summer, and \$33.5 with 25 percent of reliability risk in summer.

409 See February 21, 2023 ICAPWG presentation "2025 - 2029 ICAP Demand Curve Reset", available here.

410 See April 27, 2023 ICAPWG presentation "2025 - 2029 ICAP Demand Curve Reset: Reference Point Price Proposal", available here.

Figure A-124: NYCA Demand Curves by Share of LOLE in Summer

2022/23 Demand Curve Parameters



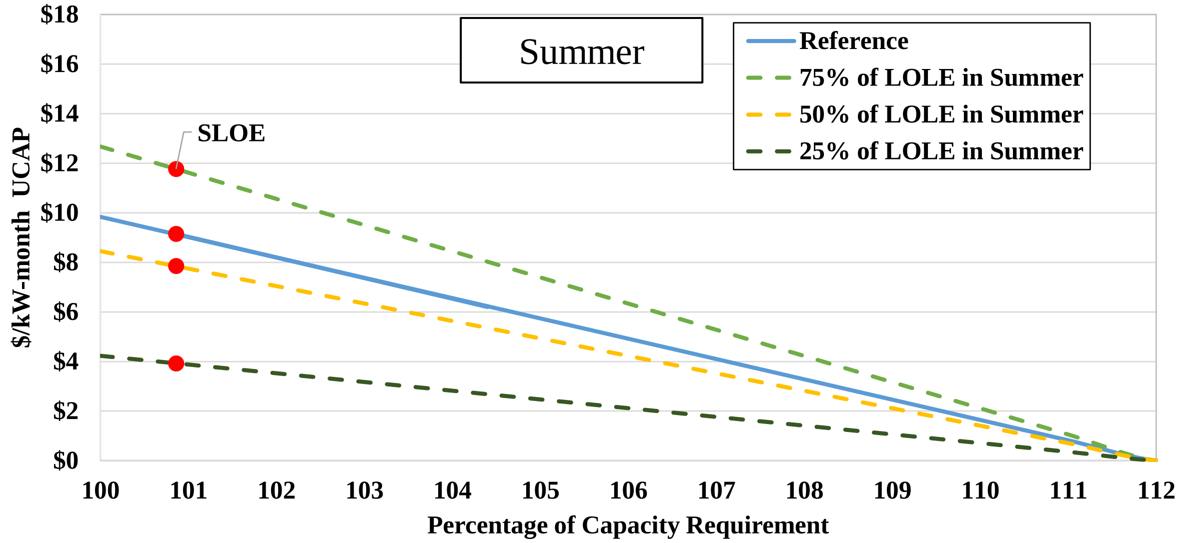


Figure A-125: NYC Demand Curves by Share of LOLE in Summer

2022/23 Demand Curve Parameters

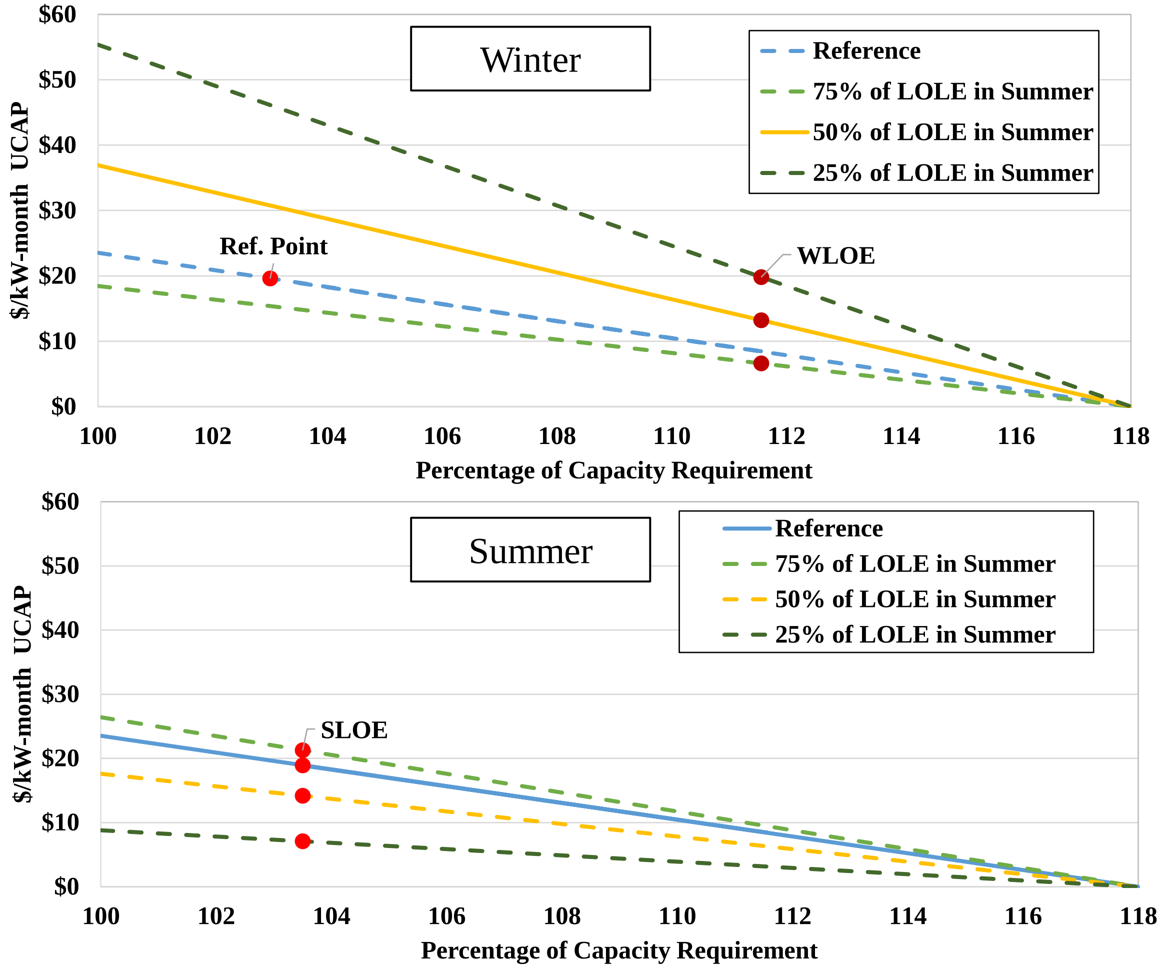
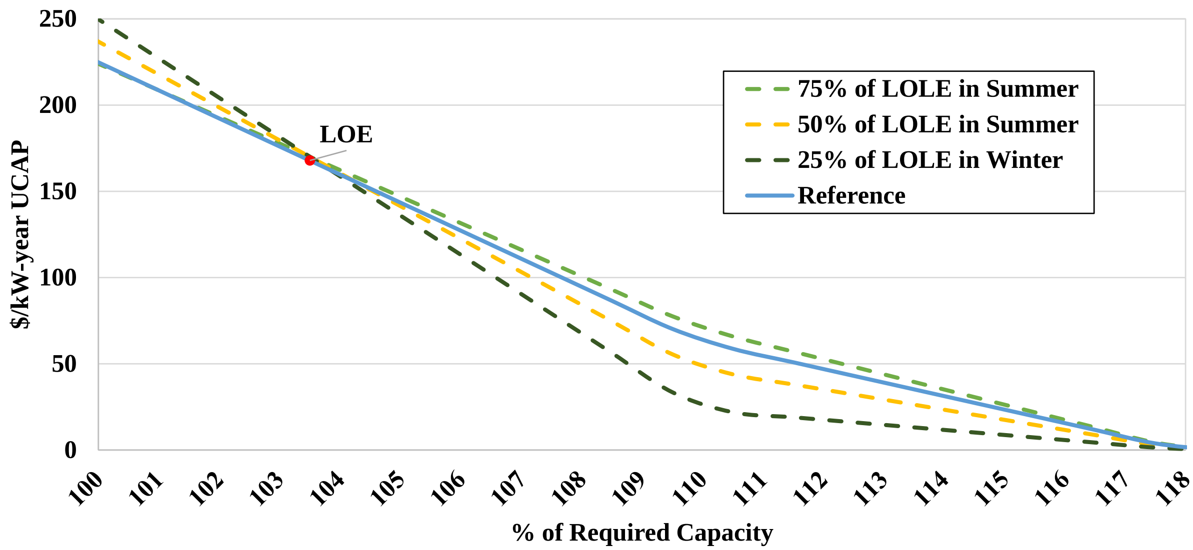


Figure A-126: Annual NYC Capacity Revenue by Share of LOLE in Summer

2022/23 Demand Curve Parameters



F. 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-21: Cost of Reliability Improvement

Table A-21 shows the CRI in each zone based on 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.[411] An Excess Level is assumed so that the demand curve in each area is set sufficiently

[411] 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

high to ensure the system never exceeds the 0.1 LOLE criteria. This modest excess results in an LOLE of 0.050 in the 2023/24 Capability Year. 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 2023/2024 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.[412]
- *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.
- *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.[413, 414] This is calculated based on the ratio of the *Net CONE of Demand Curve Unit* to the *MRI* for each area.

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.

412 These values were obtained by starting with the system at Excess Level with an LOLE of 0.0050 and calculating the change in LOLE from a 100-MW perfect capacity addition in each area.

413 For example, for Zone F: $74/kW-year × 1000kW/MW ÷ (0.0046 LOLE change/100MW) × 0.001 LOLE change = $1.7 million.

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

Table A-21: Cost of Reliability Improvement
2023/24 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	$74		0.046	0.0040	$1.9
B	$74		0.046	0.0039	$1.9
C	$74		0.046	0.0043	$1.7
D	$74		0.046	0.0043	$1.7
E	$74		0.046	0.0043	$1.7
F	$74		0.046	0.0043	$1.7
G-J Locality		0.050			
G	$84		0.045	0.0047	$1.8
H	$84		0.045	0.0050	$1.7
I	$84		0.045	0.0050	$1.7
NYC					
J	$155		0.045	0.0052	$3.0
Long Island					
K	$66		0.044	0.0059	$1.1

Figure A-127 and Figure A-128: Cost and CRI Curves in LCR Optimizer

Figure A-127 and Figure A-128 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.[415] These are shown in the top panel of each figure, which are monotonic upward-sloping marginal cost curves. These investment costs include the categories of costs that could be saved by procuring capacity more efficiently.

- *LCR Optimizer formulation* – The marginal cost function at each location is derived assuming the NYISO minimizes overall consumer costs.[416] 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.[417] For example, Figure A-127 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.

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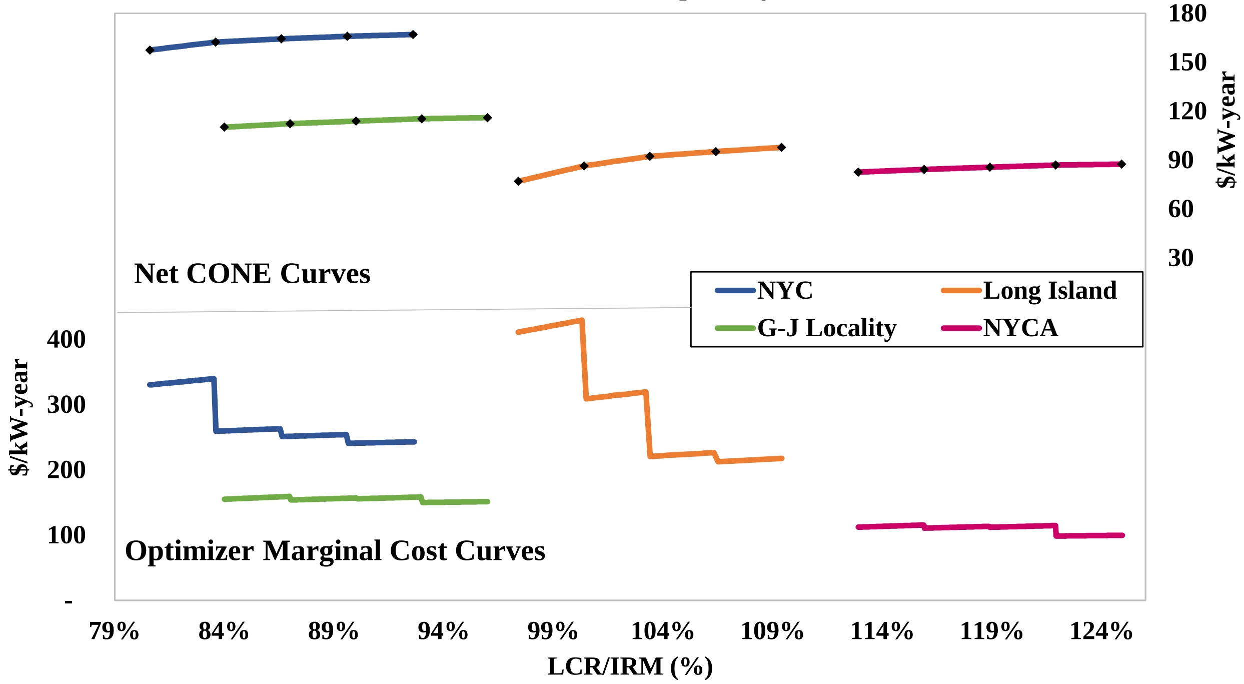
415 This is because the first-order conditions of the investment cost minimizing optimization problem include the Net CONE functions in each location.

416 The marginal cost function is derived from the first order conditions of the consumer cost minimization problem.

417 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.

For each locality in each formulation, Figure A-127 shows the marginal cost of capacity per kW-year, while Figure A-128 shows the CRI curve. Each CRI curve equals the marginal cost curve from Figure A-127 divided by the marginal reliability impact of capacity in the locality.[418 419] Thus, the CRI curve is the marginal cost of capacity per unit of LOLE improvement. The red diamonds indicate simulated LCRs determined using the LCR Optimizer cost function.

Figure A-127: Optimizer Cost Curves vs. Net CONE Curves
2022/2023 Capability Year



In Figure A-128, 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.

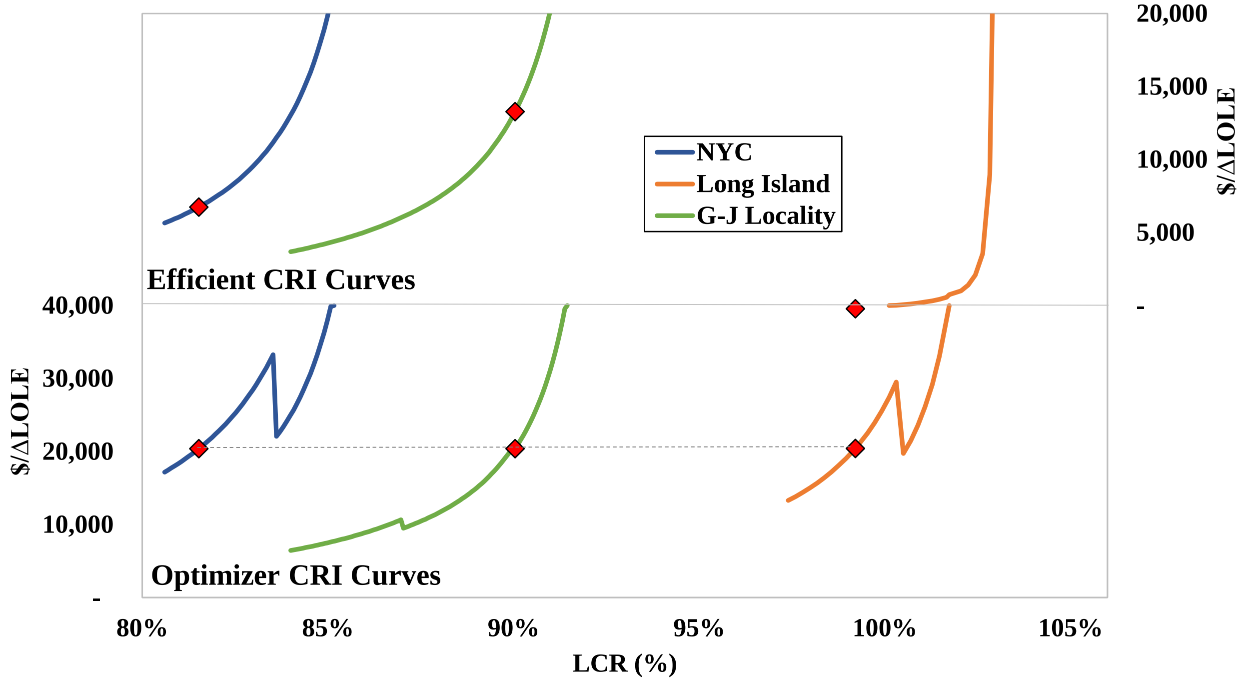
- The Optimizer does not produce efficient LCRs. In this example, the Zone K LCR is inefficiently low and the G-J Locality LCR is inefficiently high.

418 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.

419 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).

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.

Figure A-128: Optimizer CRI Curves vs. Efficient CRI Curves[420]
2022/2023 Capability Year



G. Financial Capacity Transfer Rights for Transmission Projects

Investment in transmission can significantly reduce the cost of maintaining adequate installed reserve margins, enhance the deliverability of existing resources, and reduce the effects of contingencies. Recognizing these reliability benefits of transmission projects and providing them access to capacity market revenues could provide substantial incentives to invest in transmission. In this subsection, we discuss the reliability value of transmission projects and the potential for financial capacity transfer rights ("FCTRs") in providing investment signals for merchant transmission projects.[421]

Figure A-129: Breakdown of Revenues for Generation and Transmission Projects

Figure A-129 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

420 The simulated LCRs indicated by the red diamonds in Figure A-128 differ slightly from the actual 2022/23 LCRs because MRI was simulated using a limited number of MARS data points.

421 See Recommendation 2012-1c in Section XII.

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.[422]

- 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.[423]

- 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.

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422 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.

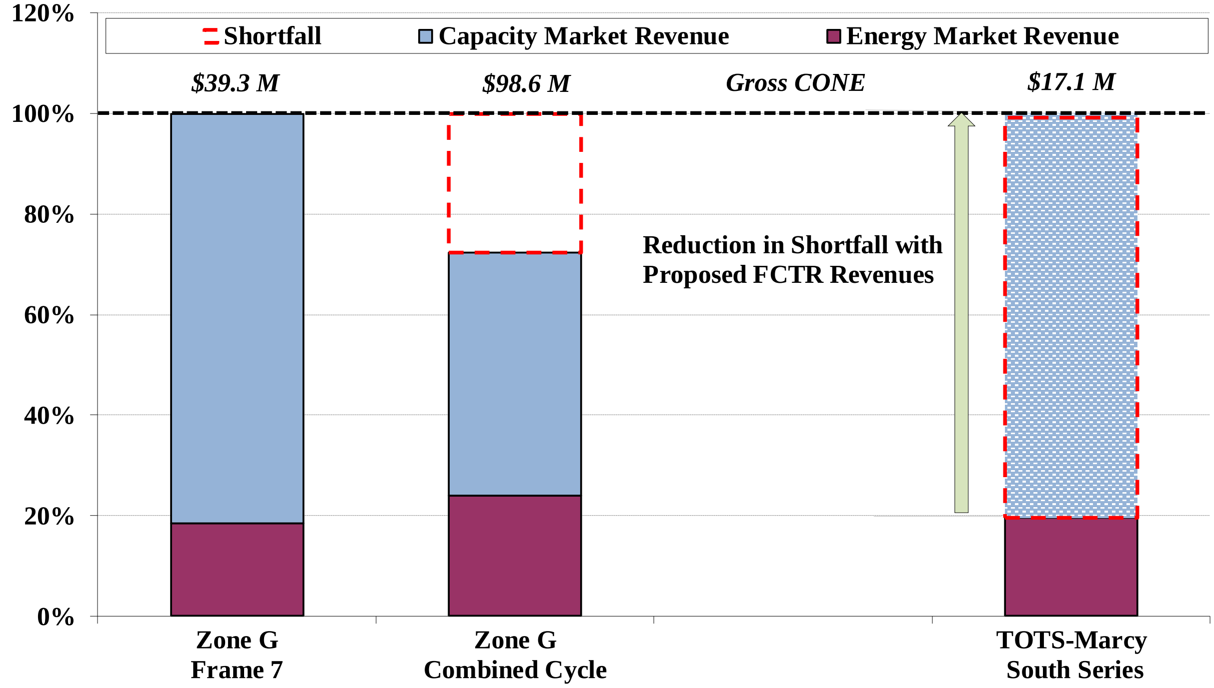
b) An investment cost of $120 million for the MSSC project (see here), inflated to 2019$.

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.

423 See NYISO Market Monitoring Unit's March 10, 2020 presentation to ICAPWG titled *Locational Marginal Pricing of Capacity – Implementation Issues and Market Issues*.

- 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-129: Breakdown of Revenues for Generation and Transmission Projects
At Level of Excess



H. Assessment of Capacity Accreditation Approaches

NYISO has recently adopted market changes that will accredit capacity suppliers based on each resource's Marginal Reliability Improvement (MRI) value beginning in the 2024/25 capability year. 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.

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. NYISO developed implementation details for its new accreditation approach in 2022.[424] 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.

[424] These details have been incorporated into NYISO's ICAP Manual – see Section 7 (Annual Process to Establish Capacity Accreditation Resource Classes, Capacity Accreditation Factors, and Peak Load Windows).

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. NYISO intends to consider resource adequacy modeling changes that would better reflect these risks in its ongoing Modeling Improvements for Capacity Accreditation project.

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.[425]

[425] 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.[426] An example of an ELCC calculation, based on a recent proposal in PJM,[427] 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 support NYISO's use of 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.

426 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.

427 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, land-based wind, and offshore wind units (subsection C), and (d) new battery storage (subsection D). Net revenues vary substantially by location, so we estimate the net revenues that each unit would have received at a number of locations across New York.

A. 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 existing 10-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, 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.[428] 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-22 to Table A-24: 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.[429] 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:

Table A-22: Day-ahead Fuel Assumptions During Hourly OFOs[430]

Technology	Gas-fired	Dual Fuel
Gas Turbine	No offer	Oil
Steam Turbine	Min Gen only	Oil/ Gas**

- Regional Greenhouse Gas Initiative ("RGGI") compliance costs are included.
- 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

428 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.

429 We assume a Frame unit is committed for an hour if the average LBMP in RTC at its node is greater than 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 the applicable start-up and incremental energy cost of the unit for one hour.

430 **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.

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.

- 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-23: Gas and Oil Price Indices and Other Charges by Region[431]

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%

- Existing GTs in NYC are modeled as not participating in the energy or capacity markets in the May through September ozone season, to reflect resource owners' compliance plans with NYSDEC Peaker Rule regulations.[432]

Table A-24: Gas-fired Unit Parameters for Net Revenue Estimates[433]

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%

431 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.

432 The Peaker Rule regulations first took effect in May 2023. The majority of affected capacity in New York City has indicated plans to either retire or cease operations during the ozone season. Although the Peaker Rule did not restrict revenues of these units in 2020 – 2022, we show only non-ozone season revenues to reflect revenues under the future operating status of these facilities.

433 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*.

- In 2022, New York State generators were in CSAPR Group 3, a cap-and-trade program requiring generators to obtain allowances for their NOx emissions during the Ozone Season. However, this allowance cost was partly offset by the provision that allowance allocations in future years will be partly based on 2022 emissions. To estimate the resulting net cost of NOx emissions in 2022, we derive the opportunity cost that would be implied if a ST emits a quantity equal to the average allowance allocation of generators in the same zone. For Hudson Valley ST units, the high NOx case corresponds to a unit with a higher level of historical allowances under the CSAPR program, while the low case corresponds to a unit with a lower level.
- 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.

Figure A-130 to Figure A-132: Net Revenues Estimates for Fossil Fuel Units

The following three figures summarize our net revenue and run hour estimates for dual-fuel units in various locations across New York. They also indicate the levelized CONE estimated in the Demand Curve Reset for comparison. Net revenues and CONE values are shown per kW-year of Summer Installed Capability. Net revenues from the sale of energy in the day-ahead market are shown separately for hours when the unit would operate on gas and hours when it would operate on fuel oil. Likewise, the additional net revenues that would be earned from the sale of day-ahead operating reserves and from participating in the balancing market are also separately for hours when the unit would operate on gas and hours when it would operate on fuel oil.

Figure A-130: Net Revenue & Cost for Fossil Units in West Zone and Hudson Valley
2020-2022

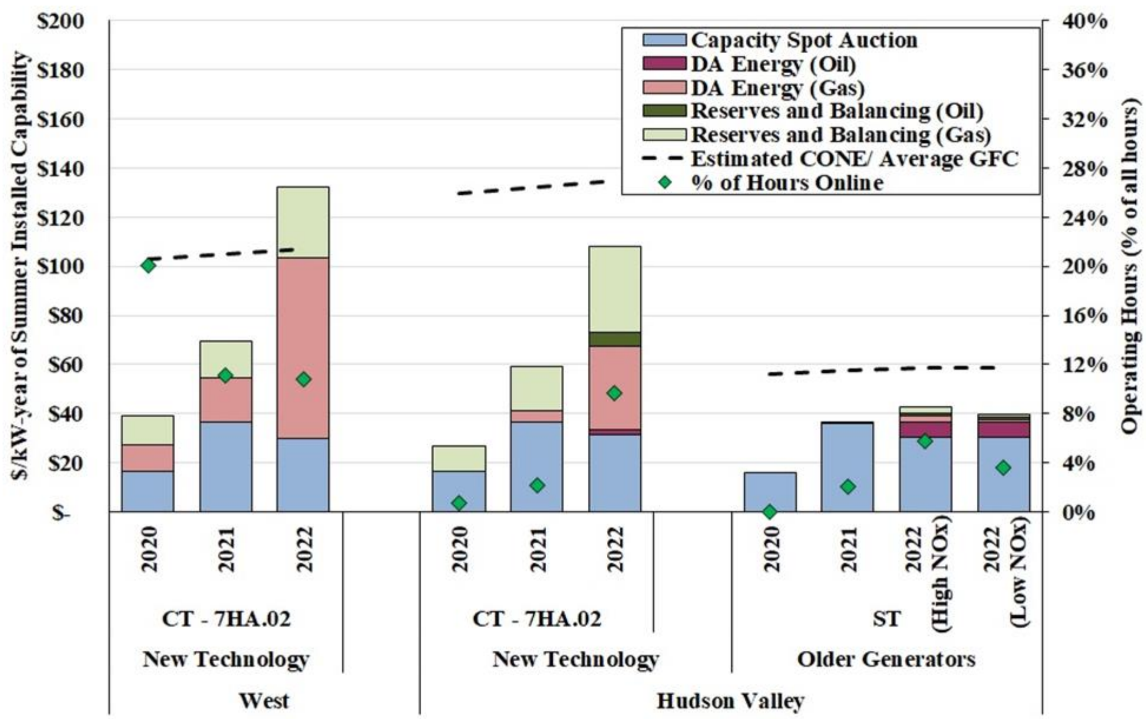


Figure A-131: Net Revenue & Cost for Fossil Units in New York City
2020-2022

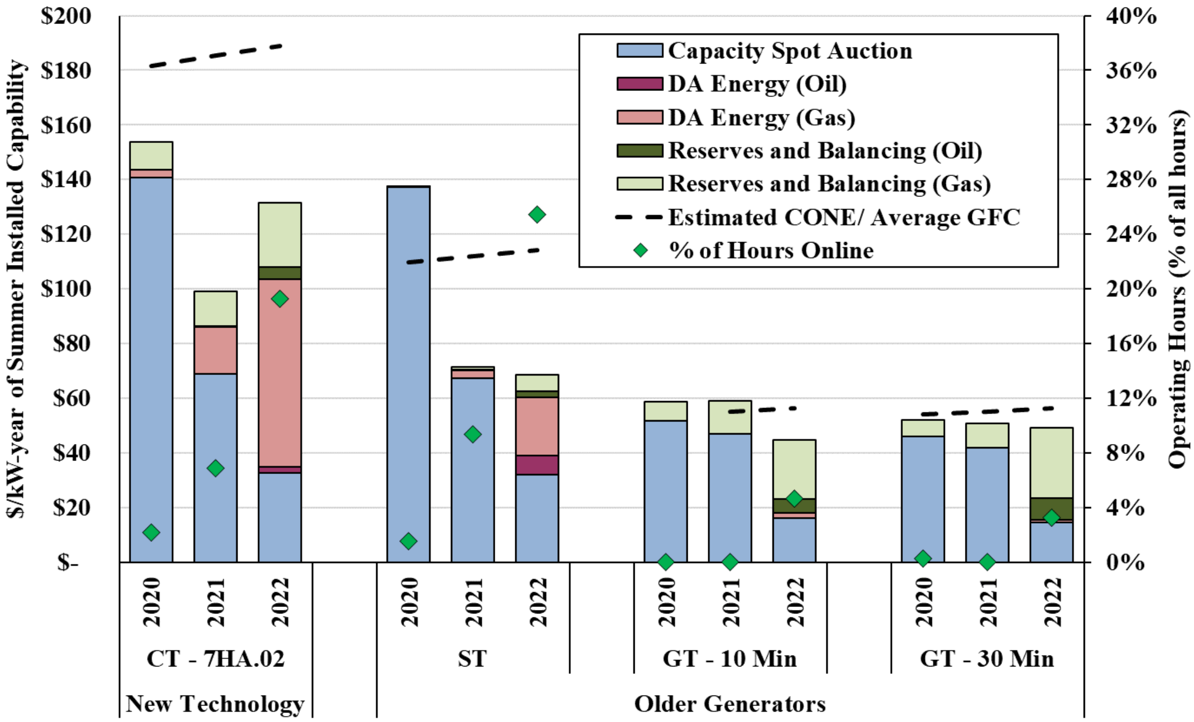
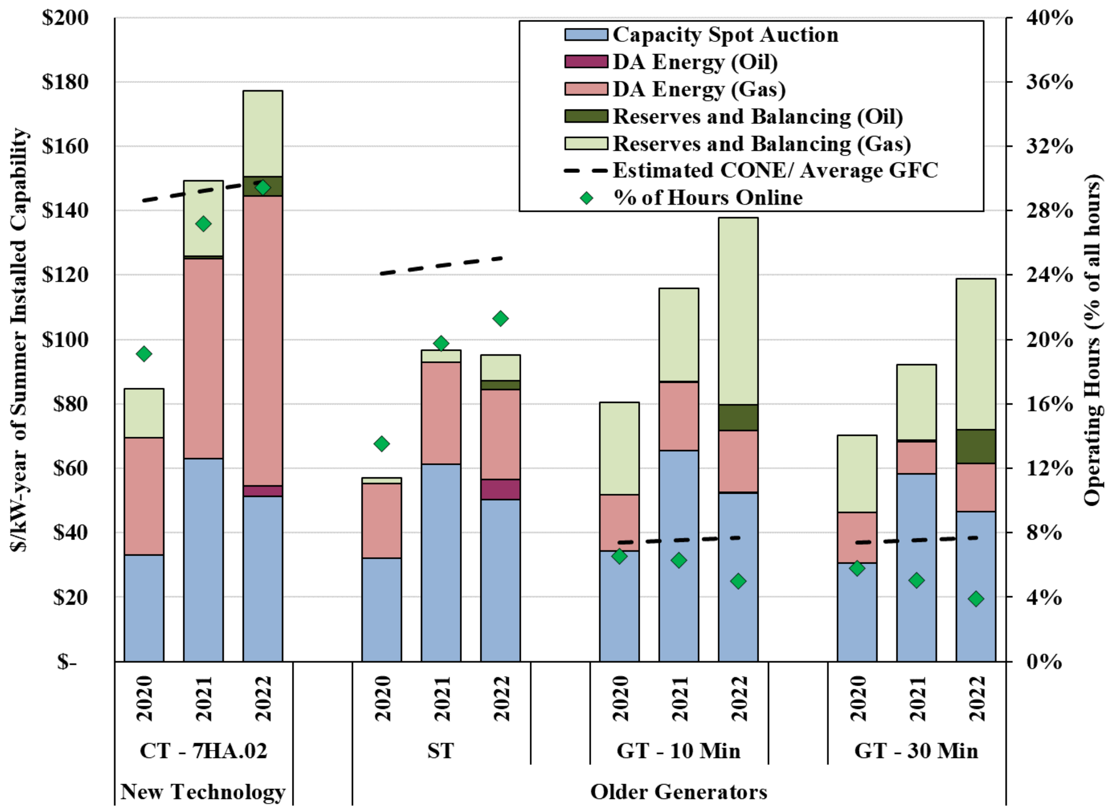


Figure A-132: Net Revenue & Cost for Fossil Units in Long Island
2020-2022



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-133: Net Revenues for Nuclear Plants

Figure A-133 shows the net revenues and the US-average operating costs for the nuclear units from 2020 to 2022. Estimated net revenues are based on the following assumptions:

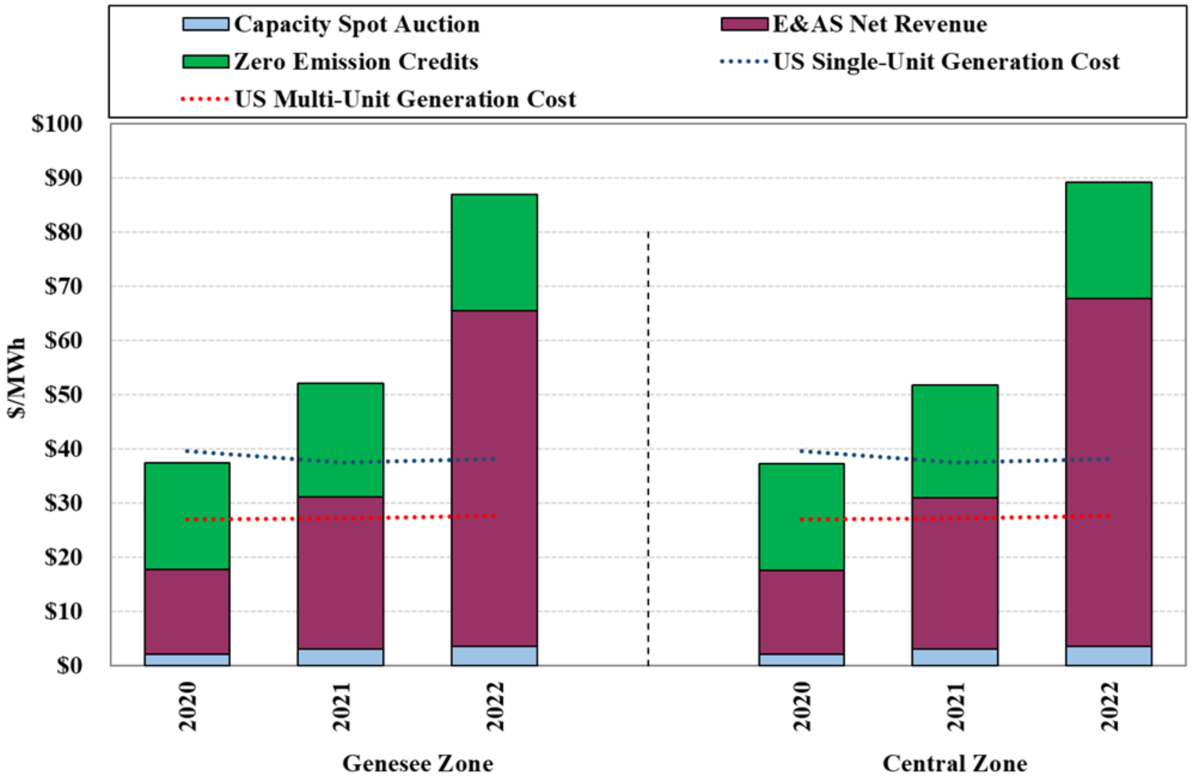
- Nuclear plants are scheduled day-ahead and only sell energy and capacity.
- Nuclear units earn energy revenues throughout the year except during periods of forced outages and outages related to refueling. We assumed an EFORd of two percent and a capacity factor of 67 percent during March and April to account for reduced output during refueling.[434]
- 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.[435]
- The nuclear units located in upstate zones are eligible for additional revenue in the form of Zero Emission Credits ("ZECs").[436] The ZEC price was \$19.59/MWh for the period April 2019 to March 2021 and \$21.38/MWh for the period April 2021 to March 2023.

434 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.

435 The average cost of operation of nuclear plants in the US are based on NEI/ EUCG reports and presentations. See here.

436 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. ZEC prices are fixed in advance for two year tranches and published by the NYDPS in Case 15-E-0302.

Figure A-133: Net Revenue of Existing Nuclear Units
2020-2022



C. Renewable Units Net Revenues

We estimate the net revenues the markets would have provided to utility-scale solar PV in the Central and Capital zones, land-based wind in the Central and North zones, and offshore wind plants interconnecting in Long Island and New York City. For each of these technologies, we estimated the revenues from the NYISO markets and the state and federal incentive programs.

Table A-25 and Figure A-134: Costs, Performance Parameters, and Net Revenues 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-25 shows cost estimates for solar PV, land-based wind and offshore wind units we used for a unit that commence operations in 2022. Costs are based on NYISO's Renewable Technology Costs study and NREL's Annual Technology baseline (ATB).[437] The table also shows the capacity factor and capacity value assumptions we used for calculating net revenues for these renewable units.

437 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 2022 NREL ATB. We used TRG 6 cost decline curve for land-based wind, and TRG 1

Table A-25: Cost and Performance Parameters of Renewable Units

Parameter	Utility-Scale Solar PV	Onshore Wind	Offshore Wind
Investment Cost (2022) (2022$/kW AC basis)	*Capital/LHV* : $1162	*Upstate NY* : $1585	*NYC/Long Island* : $3835
Fixed O&M (2022$/kW-yr)	$31	$50	$113
Federal Incentives	ITC	PTC	ITC
Project Life	20 years		
Depreciation Schedule	5-years MACRS		
Average Annual Capacity Factor	Capital/LHV: 16.8%	Central: 35.0% North: 39.0%	NYC/LI: 45%
Unforced Capacity Percentage	Summer: 46% Winter: 2%	Summer: 16% Winter: 34%	Summer: 30% Winter: 50%
Renewable Energy Credits (Nominal $/MWh)	*Onshore Wind and Solar PV:* ***2022*** *- $20.67* ***2021*** *-* $22.34 ***2020*** *-* $22.09 *Offshore Wind:* Calculated using Offshore Wind Solicitation Indexed REC strike price of $88/MWh NYC / $82/MWh LI (2022$) less energy and capacity prices.		

Assuming the operating and cost parameters shown in the table above, Figure A-134 shows the net revenues and the estimated CONE for each of the units during years 2020-2022. The CONE and net revenues of a unit in a given year correspond to those of a representative unit that commences operation in the same year.

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.[438]

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.

438 Assumed yearly capacity factors for solar PV, land-based wind, and offshore wind units are sourced from the NYISO's Renewable Technology Cost study. Hourly generation profiles from NREL are adjusted to

- 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 March 2023 NYISO Installed Capacity Manual and publicly available offshore wind OREC contracts.[439]
- 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.[440] 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.[441]
- 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 portion 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.[442] We

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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.

439 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." Future UCAP values for intermittent technologies are likely to change following implementation of marginal capacity accreditation beginning in May 2024.

440 For more information on the recent RES Tier 1 REC procurements, see here. The average Tier 1 REC sale price for LSEs to satisfy Renewable Energy Standard (RES) requirements by purchasing RECs from NYSERDA for the 2022 Compliance Year was $20.67/MWh.

441 See Appendix A and B of NYSERDA's October 2019 "Launching New York's Offshore Wind Industry: Phase I Report". We estimated a negative OREC payment for Long Island offshore wind in 2022 because index energy and capacity prices exceeded the published OREC strike price for Long Island offshore wind projects in multiple months.

442 For solar PV, the ITC was 30 percent for projects that began construction in 2019 or earlier, with a safe harbor period up to four years. Consequently, for the timeframe of our analysis, we assumed 30 percent ITC for solar PV projects.

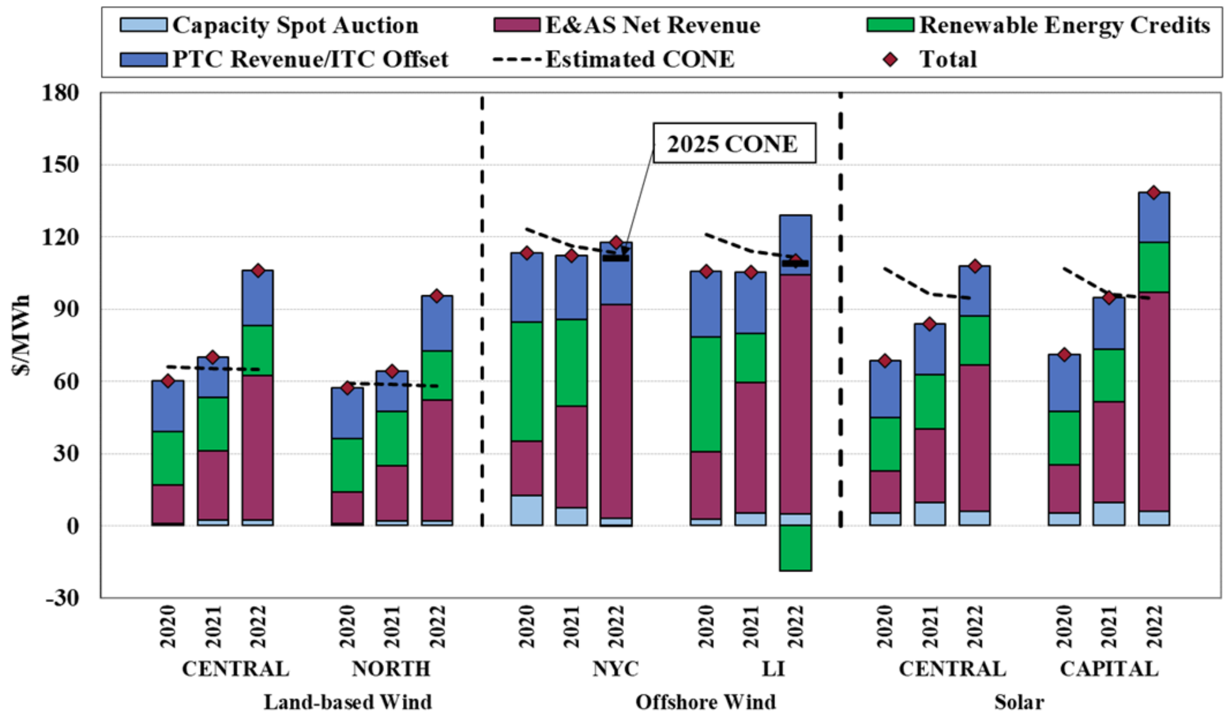
For offshore wind, the ITC is 30 percent of the eligible investment costs for projects that commence construction before 2026. The safe harbor period for the projects is up to ten years. Consequently, we assumed 30 percent ITC for offshore wind projects.

The Production Tax Credit available to land-based wind projects was 100 percent for projects beginning construction before 2017 and 80 percent in 2017. As the developers of land-based wind can safe harbor their investments for a maximum of four calendar years and receive PTC, we assumed a 100 percent PTC for projects coming in service in 2020 and an 80 percent PTC for projects entering in service in 2021. Under the Inflation Reduction Act, projects that entered service in 2022 are eligible for the full PTC at 100 percent of the new rate of 2.6 cents per kWh. 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.

incorporate the value of these federal incentives as an additional revenue stream for solar PV and wind units.[443]

- 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.

Figure A-134: Net Revenues of Solar, Land-based Wind and Offshore Wind Units
2020-2022



D. Energy Storage Revenues

We estimate the revenues the markets would have provided to energy storage resources in the West, Central, Capital, Hudson Valley, NYC, and Long Island zones. For each of these zones, we estimate the revenues from the NYISO markets and from state and federal incentive programs.

Figure A-135: Costs, Performance Parameters, and Net Revenues of Energy Storage Units

The assumed operating characteristics are as follows:

443 In addition to these federal programs, renewable power projects may qualify for several other state or local-level incentives (e.g., property tax exemptions) in New York. However, our analysis does not consider any other renewables-specific revenue streams or cost offsets beyond the revenues from sale of Renewable Energy Credits and the PTC or the ITC.

- We studied a grid-scale battery storage unit with a power rating of one MW and four hours of storage capacity. We used a model that co-optimizes energy and reserve revenues using day-ahead zonal market prices. Estimated energy and ancillary services revenues are likely conservative, because we do not include real-time market balancing revenues. We limit the injections and withdrawals to one cycle per day. The operating characteristics of this unit are summarized below in Table A-26
- Capacity credit for a four-hour storage resource is assumed to be the currently effective rate of 90 percent. NYISO will implement marginal capacity accreditation beginning in May 2024, which will cause capacity value to vary each year. High penetrations of storage may cause its UCAP value to decline over time.
- Bulk storage resources are assumed to be eligible for the NYSERDA Bulk Storage Incentive program, at a rate of $75 per kWh of installed storage capacity.[444] We levelize this benefit over the course of the project's life using a merchant cost of capital.
- Standalone battery storage entering service through 2022 was not eligible for the federal Investment Tax Credit, but storage projects entering service beginning January 1, 2023 will quality for a 30 percent ITC. We show the impact that the ITC would have had on storage economics in Figure A-135.

Table A-26: Operating Parameters and CONE of Battery Storage Unit[445]

Characteristics	Storage
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%

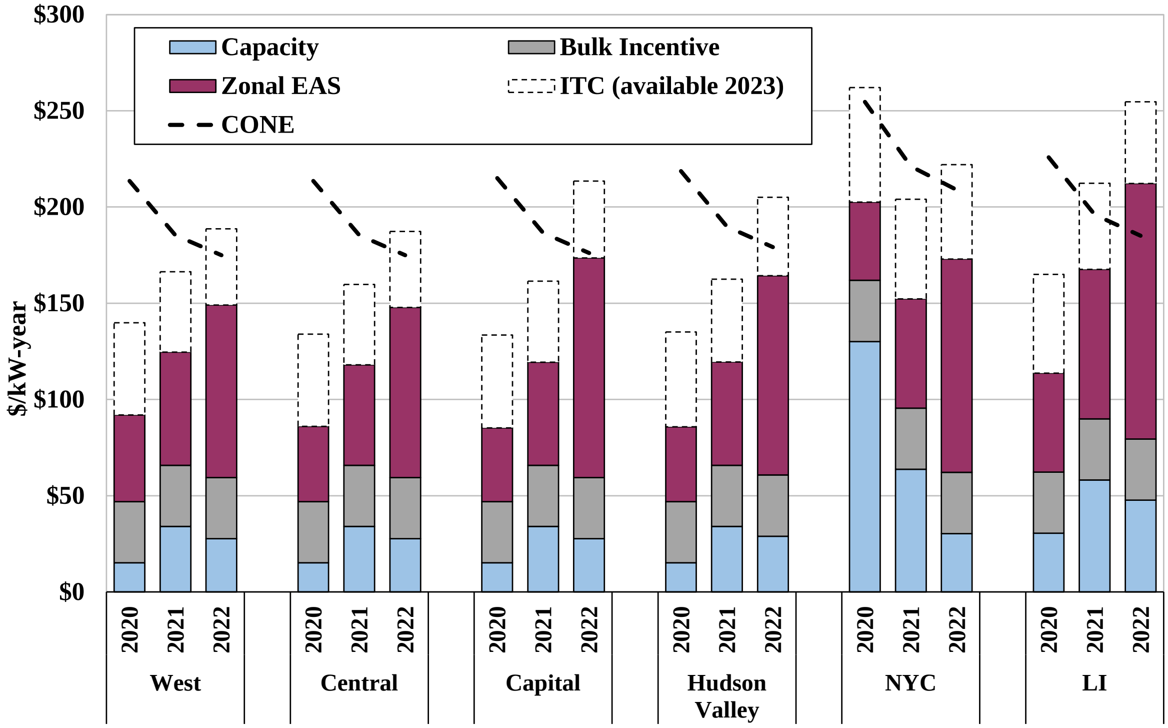
Assuming the operating and cost parameters shown in the table above, Figure A-135 shows the net revenues and the estimated CONE for each of the units during years 2020-2022. The CONE and net revenues of a unit in a given year correspond to those of a representative unit that commences operation in the same year.[446]

444 See here. Bulk projects in Con Edison service territory are eligible to compete for contracted payments from the utility instead of this bulk incentive; for this analysis we assume the incentives to resources in Zone J under this approach are comparable to the bulk storage incentive available elsewhere.

445 Cost assumptions are based on the NREL 2022 ATB and NYISO's 2020 ICAP Demand Curve Reset study. These sources may not reflect reported cost increases of storage project components in 2022.

446 In addition to revenues from capacity, E&AS, and Bulk Incentive, we show theoretical revenues from the ITC, which is available starting in 2023, and the impact that these additional revenues would have had on units had the ITC been available in previous years.

Figure A-135: Net Revenues and CONE of Energy Storage Units
2020-2022



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.[447]

- 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.[448]

- 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.[449] 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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447 Resources participate in EDRP through Curtailment Service Providers ("CSPs"), which serve as the interface between the NYISO and resources.

448 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.

449 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 project, which is scheduled for implementation in 2023-Q2, will allow individual large consumers and aggregations of consumers to participate more directly in the market. This will better reflect duration limitations in their offers, payments, and obligations. The NYISO will retire both the DSASP and DADRP programs once the DER Participation Model is implemented. Current DSASP and DADRP resources will be required to either transition to the DER Participation Model or withdraw from the market.

This section evaluates the performance of the existing programs in 2022 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.

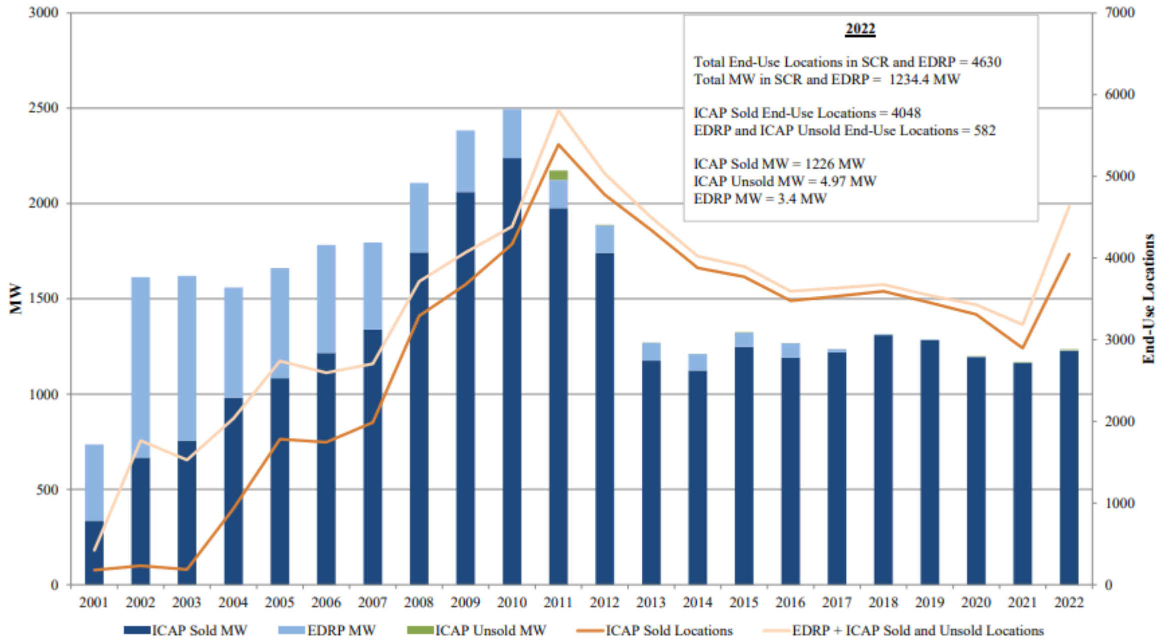
Figure A-136: Registration in NYISO Demand Response Reliability Programs

Figure A-136 summarizes registration in two of the reliability programs at the end of each summer from 2001 to 2022 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. [450]

Figure A-136: Registration in NYISO Demand Response Reliability Programs [451]
2001 – 2022



B. Economic Demand Response Programs

The NYISO offers two economic demand response programs.[452] First, the DADRP program allows retail customers to offer load curtailment in the day-ahead market in a manner similar to

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450 See Section 4.1.1 of ICAP Manual for more details.

451 This figure is excerpted from *NYISO 2022 Annual Report on Demand Response Programs*, January 31, 2023, available at: www.nyiso.com/demand-response.

452 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.

generation supply offers, currently subject to the Monthly Net Benefit Offer Floor.[453] Like a generation resource, DADRP participants may specify minimum and maximum run times and hours of availability. Load reductions scheduled in the day-ahead market obligate the resource to curtail the next day. Failure to curtail results in the imposition of a penalty for each such hour equal to the product of the MW curtailment shortfall and the greater of the corresponding day-ahead and the real-time price of energy. 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. Currently, six DSASP resources in Upstate New York actively participated in the market as providers of operating reserves. These six resources collectively can provide up to 225 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

453 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

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-27 summarizes the reliability demand response events in 2022. 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 and affected LBMPs in how many intervals. In 2022, the scarcity pricing rule was triggered for a total of 21 five-minute intervals during the two events.

Table A-27: Summary of Reliability Demand Response Activations
2022

DR Program	Event Date	Start Time	End Time	Event Zone	Obligated ICAP MW	# of 5-Minute Intervals w/ Scaricity Pricing Triggered
SCR/EDRP	7/19/2022	16:00	22:00	F	114.2	8
SCR/EDRP	7/20/2022	15:00	22:00	F	114.2	13