Memorandum

To: NYISO Staff

From: David Patton, Pallas LeeVanSchaick, and Joseph Coscia

Date: October 27, 2025

Re: MMU Comments on the 2025 Q3 Short Term Assessment of Reliability (STAR)

As NYISO's Market Monitoring Unit (MMU), our goals are to help ensure that the markets administered by the ISO function efficiently and to identify and report on market design flaws. We submit these comments on the implications of the 2025 Q3 STAR for NYISO's markets.

In this STAR Report, NYISO determined that up to 1,130 MW of capacity in New York City and 254 MW in Long Island are needed to avoid capacity deficiencies from 2026 to 2030, which will be retained through out-of-market contracts. This will likely reduce New York City capacity prices below the going forward costs of many generators and cause additional generators to consider retirement. On Long Island, the generators seeking to retire are relatively new and would likely be economic to remain in service if capacity prices were consistent with their reliability value, but Long Island capacity prices are consistently inefficiently low.

These developments raise concerns about the ability of the wholesale market to retain needed resources and the likelihood that NYISO will be compelled enter into additional out-of-market contracts to maintain adequate resources. This memo describes these concerns and provides our recommendations to address them through the market.

A. Misalignment of Market and Planning Requirements in New York City

One of the main causes the premature retirement of resources that are needed for reliability is the misalignment between the Reliability Planning Process (RPP) and the NYISO capacity market that we highlighted in our comments on the 2024 RNA and 2025 CRP.[1] The RPP establishes planning requirements that exceed the market's requirements because of: (a) inconsistent modeling assumptions between the planning and market studies for the same time period, and (b) the use of speculative future scenarios in planning studies that ignore market responses to tightening margins. Key drivers of the STAR's New York City Reliability Need that drive differences between planning and market requirements include:

- *Inconsistent forced outage rate assumptions*: capacity market requirements are determined using lower forced outage rates than the planning studies. New York City's capacity market LCR would be approximately 350 MW higher if consistent outage rate assumptions were used.

[1] See MMU Comments on the 2024 RNA here and on the 2025 CRP here.

- *Use of "higher demand" load forecast*: NYISO determines the magnitude of Reliability Needs based on a "higher demand forecast" which exceeds the baseline demand forecast by 130 MW in 2026 growing to 630 MW by 2030. The "higher demand" forecast assumes higher economic growth than expected and that future electrification policies will not provide incentives to avoid charging EVs during peak conditions.
- *Exclusion of planned projects*: NYISO excludes the contributions of several planned generation and transmission projects that are included in its base case assumptions when quantifying future Reliability Needs. These projects are expected to contribute to New York City's transmission security margin by: 800 MW starting in 2026 (CHPE), 80 MW in 2027 (Empire Wind I), and 100 MW in 2030 (Propel NY Energy – Alternate 5).

Since the Reliability Needs are driven by assumptions that are more conservative than expected future conditions, the effective planning requirements will likely exceed the future market requirements. For example, the factors listed above will result in effective planning requirements for 2029 exceeding the market requirements by 350 to 930 MW, depending on whether planned projects enter service as scheduled and whether load growth follows a trajectory that more closely resembles the baseline or 'high demand' scenario.[2]

Setting market requirements consistently below planning requirements undermines the market's ability to provide incentives to satisfy the planning needs. The resulting declaration of Reliability Needs will lead to out-of-market actions that increase capacity market surpluses and lower expected capacity prices. The expectation of low capacity prices weakens incentives to maintain generating capacity in a reliable condition, repair equipment following outages, participate in demand response programs, and import capacity. For example, we project New York City capacity prices of approximately $7.0 per kW-month in summer 2026 after CHPE enters service if the Gowanus and Narrows peaking resources are retained to address Reliability Needs.[3] This is likely well below the long-term going-forward costs (GFCs) of many resources in New York City, which would increase pressure on other existing generators to retire.

The alignment between the NYISO markets and planning could be improved with changes to the following market parameters and reliability planning assumptions:

- *Market forced outage rates*: The generator outage rates used to set capacity market requirements significantly overestimated generators' availability during recent peak load conditions.[4] These assumed outage rates may be biased downward because of: (a) underreporting of partial forced derates, (b) misclassification of some forced outages as planned outages, and (c) aspects of the EFORd calculation that overestimate availability of units that usually run at low output levels.
- *Treatment of future projects in planning studies*: Planning studies should not assume unreasonable delays of planned projects that otherwise meet inclusion criteria in scenarios used to declare Reliability Needs. Assuming indefinite delays of projects that

[2] This assumes that NYISO will re-assess the magnitude of the Reliability Need in 2029 to account for the contribution of CHPE once it enters service, which is expected in 2026.

[3] The continued retention of peaking resources is an example; NYISO has not committed to any specific solution.

[4] See 2025-Q2 Quarterly State of the Market Report here, slide 6.

have achieved advanced milestones is unreasonable and could lead to excessive declaration of Reliability Needs. Placing limits on the potential delays (e.g., one year from the planned in-service date and/or a percentage of the remaining timeline) could strike a reasonable balance.

- *Plausibility of scenario assumptions*: Planning studies should avoid declaring Reliability Needs based on scenarios that unrealistically ignore market responses to tightening capacity margins. For example, market and regulatory responses make a scenario of runaway load growth due to electric vehicle charging during the peak hour unlikely.

Changes to capacity market demand curves (such as the targeted level of excess capacity) may be needed to ensure the market sets adequate prices when the planning process indicates a potential need for reliability. However, such a change would be costly to consumers, so it is preferable to improve the alignment of the planning and market processes to the extent possible.

B. Market Design Flaws Highlighted by 2025 Q3 STAR

The 2025 Q3 STAR evaluated the proposed generator deactivations of two Long Island facilities that are *not* obligated to retire by state environment regulations (the Far Rockaway and Pinelawn facilities). Failures to appropriately compensate suppliers for the reliability they provide may lead to inefficient retirements, investment, imports and demand response. Eventually, this leads to Reliability Needs that could have been avoided by better market signals. Below is a list of market design shortcomings we have previously identified in our State of the Market or other reports that will tend to weaken market responses to the issues identified in the 2025 Q3 STAR.

- *Inefficiently-Low Locational Capacity Requirement for Long Island*: the capacity market LCR for Long Island is routinely set at an inefficiently low level due to flaws in NYISO's LCR Optimizer method.
  - For example, the reliability value of capacity, as reflected in the Marginal Reliability Impact (MRI) of capacity, is 230 percent higher in Long Island than New York City, but the LCR for Long Island is so low that the Long Island capacity price usually exhibits little or no premium over the NYCA capacity price.[5]
  - The low LCR along with other flaws in the capacity demand curves for the four-year period beginning May 2025 have led to capacity prices in Long Island that are substantially below the net cost of new entry and under the going-forward costs of much of the existing capacity.[6] Long Island's capacity demand curve is based on an Net CONE estimate of $97 per kW-year (UCAP), compared to estimated going-forward costs of $128 to $147 per kW-year for some existing steam units.[7]
- *Lack of Granular Capacity Zones*: Reliability Needs may arise because of local capacity requirements that are not represented in the capacity market. As a result, the market may

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5 See slide 34 of NYISO's presentation "2026-2027 Informational CAFs (iCAF) Set 1" at slide 34, available here.

6 See our comments on NYISO's 2024 Demand Curve Reset filing, available here.

7 This estimate is derived from public information from the long term Power Supply Agreement currently in effect between LIPA and National Grid, FERC Form 1 cost data reported for Long Island generators, and recent property tax settlements between LIPA and host communities.

fail to retain capacity or attract entry or demand response in those areas. We have recommended establishing more granular capacity zones that would better reward capacity in import-constrained areas and avoid overpaying capacity in export-constrained areas.[8] The details of the 2025 Q3 STAR suggest that capacity zones in New York City's 138 kV system, southwestern Long Island, and the area encompassing zones H through K are needed to provide efficient investment incentives.[9]

- *Use of Out of Merit Dispatch Instead of Day-Ahead and Real-Time Constraints*: The 2025 Q3 STAR finds a non-BPTF deficiency on the 69 kV system in Long Island due to the deactivation of the Far Rockaway GTs. These units are frequently dispatched out of merit in actual operations to manage network constraints that are not modeled in the market (roughly 800 unit-hours in the past 12 months).[10] Modeling transmission constraints in the market provides more efficient incentives to resources that can help manage the constraints. The use of out-of-market dispatch and cost-based compensation provides incentives for units to operate inefficiently by rewarding higher-cost resources.[11]
- *Overpayment of Resources with Low Transmission Security Value*: The 2025 Q3 STAR finds Reliability Needs driven by transmission security requirements. When the capacity market LCR is set at its transmission security-based floor (as has been the case consistently in New York City), resources that cannot contribute to meeting transmission security needs are compensated as if they do. After the entry of the CHPE line, which is expected in the summer of 2026, we estimate that 925 MW of UCAP that does not satisfy transmission security-based capacity needs will receive inefficiently high capacity payments.[12]

Addressing these market design issues along with the misalignment between the planning and market requirements will be key for allowing the market to facilitate investment and retirement decisions that satisfy the NYISO's planning requirements. This should reduce the need for the NYISO to address Reliability Needs through out-of-market actions that raise costs and further undermine the performance of the markets. We look forward to discussing these comments and addressing any questions they may raise.

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8 See discussion of Recommendation #2022-4 in section VIII.C of our 2024 State of the Market Report, available here.

9 The local capacity needs in New York City and Long Island are discussed in pages 45-48 of the STAR Report, while the capacity need for Zones H-K during winter are identified on page 98.

10 Data on operator-initiated commitments can be found on NYISO's website here.

11 For example, it is noteworthy that from 2021 to 2025, Far Rockaway Unit 2 operated on natural gas in 92 percent of its run hours. However, from October 2024 through September 2025, the same facility operated on diesel oil in 100 percent of its run hours. These percentages can be estimated using the EPA's publicly available CAMPD data.

12 This includes 300 MW of demand response, 200 MW at the Ravenswood facility, and 425 MW of the CHPE line (using approximate zonal average derating factors). See section VIII.E and Recommendation 2022-1 in our 2024 State of the Market Report, available here.