# Short-Term Assessment of Reliability: 2025 Quarter 4

A Report by the
New York Independent System Operator

**January 13, 2026**

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## Executive Summary

This report sets forth the 2025 Quarter 4 Short-Term Assessment of Reliability ("STAR") findings for the five-year study period of October 15, 2025, through October 15, 2030, considering forecasts of peak power demand, planned upgrades to the transmission system, and changes to the generation mix over the next five years. The deactivation of Dahowa Hydro as an Initiating Generator[1] is evaluated in this STAR. There are no new needs identified associated with the ICAP Ineligible Forced Outage (IIFO) of Dahowa Hydro or other system changes included in this STAR.

This STAR observes no changes to the scope, scale, or nature of the Generator Deactivation Reliability Needs in New York City and Long Island included in the solution solicitation issued by the NYISO on November 10, 2025, following the 2025 Quarter 3 STAR. On January 9, 2026, the NYISO received the proposed solutions to these needs and is in the process of assessing the proposals. The NYISO will evaluate the proposed solutions and issue a Short-Term Reliability Process Report indicating the NYISO's selection of a solution or combination of solutions, along with a reasoned explanation regarding why particular generation and/or transmission solutions were selected. If proposed solutions, either individually or in combination, are not viable or sufficient to meet the identified needs, interim solutions must be in place to keep the grid reliable. The NYISO's solution selection process is designed to ensure that executing a Reliability Must Run (RMR) Agreement with generators is a last resort to addressing a reliability need.

The risk of deficiencies beyond the needs previously identified is even greater when considering a range of plausible futures with combined risks. Aging thermal plants, volatile demand driven by electrification and large industrial loads, and the potential for delays in major renewable and transmission projects all contribute to a more complex and less predictable operating environment. The NYISO continues to monitor the status of the planned Empire Wind and Sunrise Wind offshore wind projects, considering the December 22, 2025, orders by the Bureau of Ocean and Energy Management (BOEM) to suspend all ongoing activities.[2] The 2025-2034 Comprehensive Reliability Plan, issued in November 2025, provides further information regarding reliability risks over the next ten years.[3]

[1] Per OATT 38.1, an "Initiating Generator" is "a Generator with a nameplate rating that exceeds 1 MW that submits a Generator Deactivation Notice for purposes of becoming Retired or entering into a Mothball Outage or that has entered into an ICAP Ineligible Forced Outage pursuant to Section 5.18.2.1 of the ISO Services Tariff, which action is being evaluated by the ISO in accordance with its Short-Term Reliability Process requirements in this Section 38 of the ISO OATT."

[2] The BOEM suspension of ongoing activities at Empire 1 can be found here and Sunrise Wind here.

[3] 2025-2034 Comprehensive Reliability Plan (here)

### New York City Generator Deactivation Reliability Need

This STAR continues to observe the BPTF deficiency identified in the 2025 Quarter 3 STAR in New York City. There are no changes to the scope, scale, or nature of the need that the 2025 Quarter 3 STAR identified in New York City and for which the NYISO solicited solutions on November 10, 2025.

The Generator Deactivation Reliability Need in Zone J is on the BPTF and is driven by the deactivation of Gowanus and Narrows Generators (672 MW nameplate total) in combination with other factors, such as: the range in the demand forecasts based on expected weather, expected generator availability, transmission limitations, and risks associated with the availability of key future planned projects (hereinafter, "New York City BPTF Need"). The scope of the New York City BPTF Need as specified in the November 10, 2025 solution solicitation is shown in the table below.

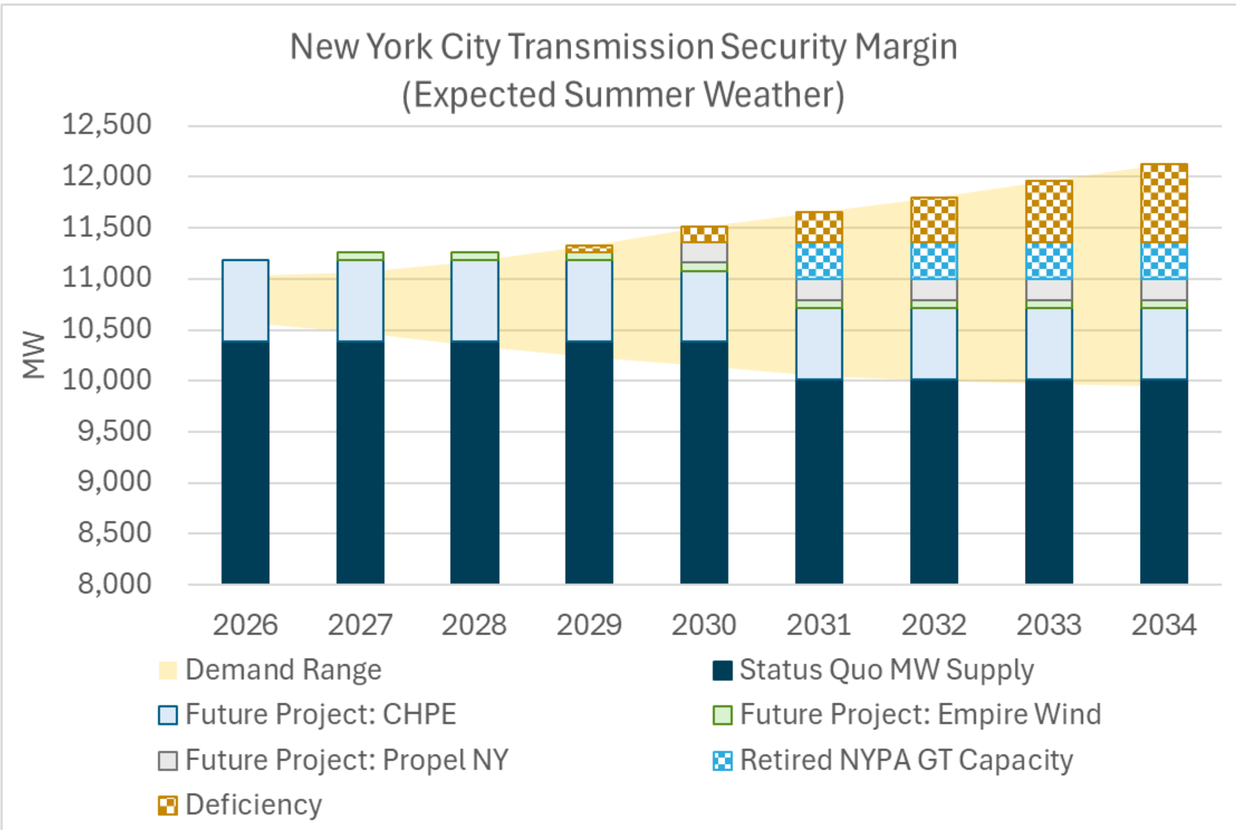
**New York City BPTF Need Included in Solicitation**

| Summer Peak | 2026 | 2027 | 2028 | 2029 | 2030 |
|---|---|---|---|---|---|
| MW Deficiency | 650 | 680 | 790 | 950 | 1,130 |
| Duration (hours) | 8 | 9 | 11 | 13 | 13 |
| MWh | 3,569 | 3,782 | 6,658 | 8,794 | 10,922 |

Once CHPE, Empire Wind, and Propel NY Public Policy Transmission Project enter service and demonstrate their planned power capabilities, the margins within Zone J are expected to improve substantially, but the margins gradually erode thereafter as expected demand for electricity grows. As detailed in the 2025 Quarter 3 STAR and the solution solicitation, even assuming these future planned projects enter service according to their schedules and demonstrate their planned power capabilities and assuming no other generators become unavailable, Zone J would still have observed needs during the summer peak periods of 2029 and 2030 (68 MW in 2029 and 148 MW in 2030). While these planned projects are advancing in their development, the completion is subject to inherent risks commonly observed among large infrastructure projects that may impact timely completion and energization. Figure 1 provides a summary of the factors affecting the New York City bulk power transmission security margin and illustrates the range of potential deficiency until system plans are completed and demonstrate their planned power capabilities to address the identified reliability needs.

The Lower Hudson Valley also has a deficiency of 195 MW over 3 hours (729 MWh) in summer 2030. As described in the 2025 Quarter 3 STAR, the Lower Hudson Valley deficiency is primarily an exacerbation of the New York City BPTF Need and is also impacted by the BPTF Generator Deactivation Reliability Need identified in Zone K. Accordingly, the NYISO did not separately seek solutions to address the deficiency for the Lower Hudson Valley beyond the solutions for the identified needs in Zones J and K. If there remains a deficiency in the Lower Hudson Valley following evaluation of proposed solutions to address the needs in Zones J and K, the NYISO would address it through the Reliability Planning Process.

**Figure 1: Factors Affecting New York City Transmission Security Margin**



### Long Island Generator Deactivation Reliability Needs

This STAR continues to observe the Generator Deactivation Reliability Needs in the Long Island locality but with changes to scope of the BPTF need as detailed in the solution solicitation issued by the NYISO on November 10, 2025. Specifically, following the publication of the 2025 Quarter 3 STAR, the NYISO received updates to key assumptions in Zone K, which impacted the observed Long Island BPTF Need. Notably, certain large load projects in Zone K, which were included in the expected weather forecast in the Gold Book, have been removed from the model based on updates received from LIPA.[4] The impact of these demand updates on the Long Island BPTF deficiencies was incorporated in the solution solicitation issued on November 10, 2025.

The scope of the Generator Deactivation Reliability Needs in Long Island that the NYISO solicited solutions to address are shown in the tables below. The Long Island BPTF need is primarily driven by the deactivation of Pinelawn (82 MW nameplate) and the Far Rockaway GTs (121 MW nameplate total), while the Long Island Non-BPTF need is driven by the deactivation of the Far Rockaway GTs. The Interim Service Provider (ISP) rate for the Pinelawn and Far Rockaway GTs became effective December 25, 2025.

**Long Island BPTF Need Included in Solicitation**

| Summer Peak | 2026 | 2027 | 2028 | 2029 | 2030 |
|---|---|---|---|---|---|
| MW Deficiency | None | 111 | 111 | 136 | 189 |
| Duration | None | 3 | 3 | 3 | 3 |
| MWh | None | 156 | 363 | 407 | 557 |

**Long Island Non-BPTF Need (Far Rockaway Load Pocket) Included in Solicitation**

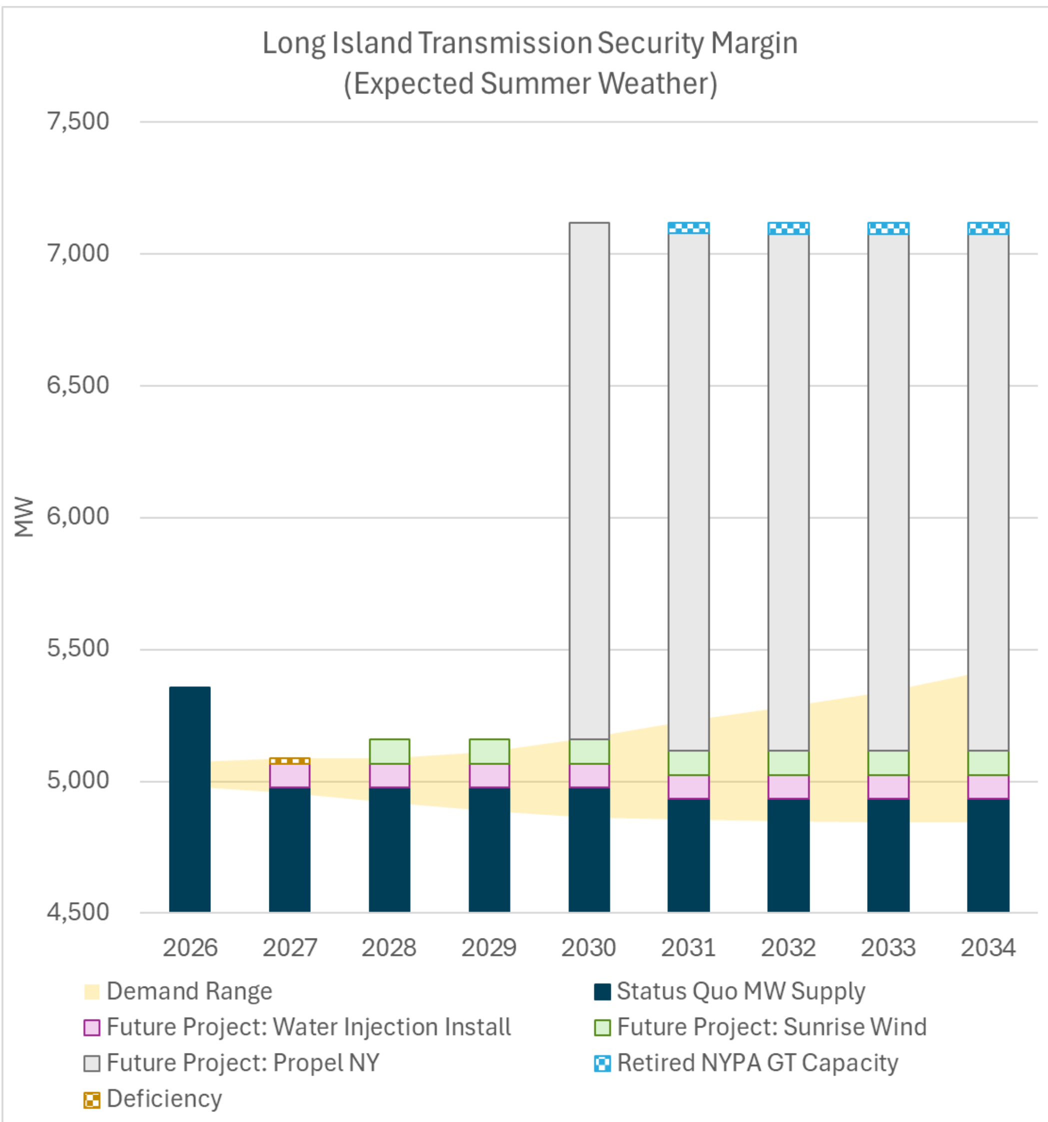
| Summer Peak | 2026 | 2027 | 2028 | 2029 | 2030 |
|---|---|---|---|---|---|
| MW Deficiency | 61 | 68 | 74 | 80 | 72 |
| Duration | 13 | 14 | 15 | 15 | 14 |
| MWh | 505 | 658 | 736 | 813 | 649 |

Figure 2 provides a summary of the factors affecting the Long Island bulk power transmission security margin and illustrates the range of a potential deficiency until system plans are completed

4 Several potential changes to the assumptions for Zone K and their impact to the observed BPTF Generator Deactivation Reliability Need were discussed with NYISO stakeholders at the November 7, 2025 ESPWG/TPAS, which presentation is posted on the NYISO's website (here).

and demonstrate their planned power capabilities to address the identified reliability needs. For instance, the recently updated DEC Peaker Rule compliance plans to install water injection at several Zone K generators planned to be in service by May 2027 shows improvement to the margins, but the margin is still deficient by 21 MW. Once Sunrise Wind (880 MW nameplate, planned in service date July 2027) is delivering power at the planned power capability, the BPTF margins continue to improve in summer 2028, followed by dramatic improvement in 2030 with the planned energization of the Propel NY project in May 2030. The BPTF margins remain positive throughout the remainder of the planning horizon. However, the Long Island BPTF Need would still be observed in summer 2027. The planned projects have negligible impact on the Long Island Non-BPTF Need.

**Figure 2 : Factors Affecting Long Island Transmission Security Margin**



### Reliability Assessment

Included in this STAR is the generator deactivation assessment for the IIFO of Dahowa Hydro. The NYISO performed a transmission security assessment of the BPTF and identified no new reliability need during the STAR study period. National Grid performed a deactivation assessment to evaluate the reliability of the local non-BPTF system with the Dahowa Hydro IIFO. No generator deactivation reliability needs were identified by the NYISO or National Grid in this STAR.

In this STAR, the NYISO performed an assessment of the Bulk Power Transmission Facilities ("BPTF") and identified no new reliability needs or changes to the scope, scale, or nature of the Generator Deactivation Reliability Needs in New York City and Long Island solicited for following the 2025 Quarter 3 STAR.

The wholesale electricity markets administered by the NYISO are an important tool to help mitigate reliability risks. The markets are designed, and continue to evolve and adapt, to send appropriate price signals for new market entry and the retention of resources that assist in maintaining reliability. The potential risks and resource needs identified in the NYISO's analyses may be resolved by new capacity resources coming into service, construction of additional transmission facilities, and/or increased energy efficiency and integration of demand-side resources. The NYISO is tracking the progression of many projects that may contribute to grid reliability that have not yet met the inclusion rules for reliability assessments. The NYISO will continue to monitor these resources and other developments to determine whether changing system resources and conditions could impact the reliability of the New York bulk electric grid. Specifically, through the quarterly STAR reports, the NYISO will continue to reassess if the identified reliability needs persist as planned projects are energized and demonstrate their capabilities.

## Purpose

The NYISO's Short-Term Reliability Process ("STRP") with its requirements prescribed in Attachments Y and FF of the NYISO's Open Access Transmission Tariff ("OATT") evaluates the first five years of the planning horizon, with a focus on needs arising in the first three years of the study period. With this process in place, the biennial Reliability Planning Process focuses on identifying and resolving longer-term needs through the Reliability Needs Assessment ("RNA") and the Comprehensive Reliability Plan ("CRP").

The first step in the STRP is the Short-Term Assessment of Reliability ("STAR"). STARs are performed quarterly to proactively address reliability needs that may arise within five years ("Short-Term Reliability Process Needs")[5] due to various changes to the grid, such as generator deactivations, revised generator/transmission plans, and updated demand forecasts. Transmission Owners also assess the impact of generator deactivations on their non-BPTF systems. A Short-Term Reliability Process Need that is observed within the first three years of the study period constitutes a "Near-Term Reliability Need."[6] Should a Near-Term Reliability Need be identified in a STAR, the NYISO solicits and selects the solution to address the need. If a need arises beyond the first three years of the study period, the NYISO may choose to address the need within the STRP or, if time permits, through the long-term Reliability Planning Process.

This STAR report sets forth the 2025 Quarter 4 findings for the study period from the STAR Start Date (October 15, 2025) through October 15, 2030. The NYISO assessed the potential reliability impacts to the BPTF considering system changes, including the availability of resources and the status of generator/transmission plans in accordance with the NYISO Reliability Planning Process Manual.[7]

## Assumptions

The NYISO evaluated the study period using the most recent Reliability Planning Process assumptions and data available as of October 14, 2025 (*i.e.,* the day before the October 15, 2025 Q4 STAR start date). In accordance with the Reliability Planning Process inclusion rules,[8] generation and transmission projects are included if they have met significant milestones such that there is a

[5] OATT Section 38.1 contains the tariff definition of a "Short-Term Reliability Process Need."

[6] OATT Section 38.1 contains the tariff definition of a "Near-Term Reliability Need." *See also*, OATT Section 38.3.6.

[7] NYISO Reliability Planning Process Manual, July 11, 2022. *See:* https://www.nyiso.com/documents/20142/2924447/rpp_mnl.pdf

[8] *See* NYISO Reliability Planning Process Manual Section 3.

reasonable expectation of timely completion of the project. A summary of key projects is provided in Appendix C.

This assessment used the major assumptions included in the 2024 RNA, along with several updates to key study assumptions that are provided below. Consistent with the obligations under its tariffs, the NYISO provided information to stakeholders on the modeling assumptions employed in this assessment. Details regarding the study assumptions were reviewed with stakeholders at the joint Electric System Planning Working Group ("ESPWG")/Transmission Planning Advisory Subcommittee ("TPAS") meeting on November 7, 2025. The meeting materials are posted on the NYISO's website.[9]

## Generation Assumptions

Study assumptions of generators for this STAR are derived from the 2024 RNA, except for the changes to generation assumptions specified below.

### Generator Deactivation Notices

For this STAR, the deactivating generators included in this assessment are listed in Figure 3. A list of all generator deactivations, including those evaluated in prior STARs, is provided in Appendix C. Generator deactivation notices for retirement, mothball outage, or ICAP ineligible forced outage are available on the NYISO's website under the Short-Term Reliability Process.[10]

**Figure 3: 2025 Quarter 4 STAR Generator Deactivations**

| Owner/ Operator | Plant Name | PTID | Zone | Nameplate (MW) | Status | Proposed Deactivation/IIFO Date |
|---|---|---|---|---|---|---|
| Relevate ReDev Borrower II LLC | Dahowa Hydroelectric | 323763 | F | 12.3 | IIFO | 9/1/2025 |

[9] Short-Term Assessment of Reliability: 2025 Q4 Key Study Assumptions, ESPWG/TPAS, November 7, 2025 (here)

[10] *See* https://www.nyiso.com/short-term-reliability-process then Generator Deactivation Notices/Planned Retirement Notices or Generator Deactivation Notices/IIFO Notifications.

#### Peaker Rule: Ozone Season Oxides of Nitrogen (NOx) Emission Limits for Simple Cycle and Regenerative Combustion Turbines

In 2019, the New York State Department of Environmental Conservation ("DEC") adopted a regulation to limit nitrogen oxides (NOx) emissions from simple-cycle combustion turbines (referred to as the "Peaker Rule").[11] Since May 2023, over 1,600 MW of peaker units have deactivated or limited their operations. A list of peaker generators that were expected to be unavailable in the summer ozone season by May 1, 2025 is provided in Figure 4.

The DEC regulations include a provision to allow an affected generator to continue to operate for up to two years, with a possible further two-year extension, after the compliance deadline if the generator is designated by the NYISO or by the local transmission owner as needed to resolve a reliability need until a permanent solution is in place. Consistent with the DEC's regulations and detailed in the Short-Term Reliability Process report it issued on November 20, 2023, the NYISO has designated the Gowanus 2 & 3 and Narrows 1 & 2 generators (32 units total) to temporarily continue operation beyond May 2025 until permanent solutions are in place, for an initial period of up to two years (until May 1, 2027).

[11] DEC Peaker Rule, 6 N.Y.C.R.R. Part 227-3 (available here).

## Figure 4: Status Changes Due to DEC Peaker Rule

| Owner/Operator | Station | Zone | Nameplate (MW) | CRIS (MW) (1) | | Capability (MW) (1) | | Status Change Date (2) | STAR Evaluation |
|---|---|---|---|---|---|---|---|---|---|
| | | | | Summer | Winter | Summer | Winter | | |
| National Grid | West Babylon 4 (6)(7) | K | 52.4 | 49.0 | 64.0 | 41.2 | 63.4 | 12/12/2020 (R) | Other |
| National Grid | Glenwood GT 01 (4)(7) | K | 16.0 | 14.6 | 19.1 | 13.0 | 15.3 | 02/28/2021 (R) | 2020 Q3 |
| Helix Ravenswood, LLC | Ravenswood 11 (12) | J | 25.0 | 20.2 | 25.7 | 16.1 | 22.4 | 12/1/2021 (IIFO) | 2022 Q1/2023 Q3 |
| Helix Ravenswood, LLC | Ravenswood 01 (12) | J | 18.6 | 8.8 | 11.5 | 7.7 | 11.1 | 1/1/2022 (IIFO) | 2022 Q1/2023 Q3 |
| Astoria Generating Company L.P. | Gowanus 1-1 through 1-8 | J | 160.0 | 138.7 | 181.1 | 133.1 | 182.2 | 11/1/2022 (R) | 2022 Q2 |
| Astoria Generating Company L.P. | Gowanus 4-1 through 4-8 | J | 160.0 | 140.1 | 182.9 | 138.8 | 183.4 | 11/1/2022 (R) | 2022 Q2 |
| Consolidated Edison Co. of NY, Inc. | Hudson Ave 3 | J | 16.3 | 16.0 | 20.9 | 12.3 | 15.6 | 11/1/2022 (R) | 2022 Q2 |
| Consolidated Edison Co. of NY, Inc. | Hudson Ave 5 | J | 16.3 | 15.1 | 19.7 | 15.3 | 18.6 | 11/1/2022 (R) | 2022 Q2 |
| Central Hudson Gas & Elec. Corp. | Coxsackie GT (8) | G | 21.6 | 21.6 | 26.0 | 19.7 | 25.2 | 05/01/2023 | 2024 Q1 |
| Central Hudson Gas & Elec. Corp. | South Cairo | G | 21.6 | 19.8 | 25.9 | 18.7 | 23.1 | 5/1/2023 (R) | 2023 Q4 |
| Consolidated Edison Co. of NY, Inc. | 74 St. GT 1 & 2 (10) | J | 37.0 | 39.1 | 49.2 | 37.8 | 43.6 | 05/01/2023 | 2022 Q2 |
| NRG Power Marketing LLC | Astoria GT 2-1, 2-2, 2-3, 2-4 | J | 186.0 | 165.8 | 204.1 | 138.0 | 184.2 | 5/1/2023 (R) | 2022 Q2 |
| NRG Power Marketing LLC | Astoria GT 3-1, 3-2, 3-3, 3-4 | J | 186.0 | 170.7 | 210.0 | 139.1 | 180.4 | 5/1/2023 (R) | 2022 Q2 |
| NRG Power Marketing LLC | Astoria GT 4-1, 4-2, 4-3, 4-4 | J | 186.0 | 167.9 | 206.7 | 138.5 | 178.6 | 5/1/2023 (R) | 2022 Q2 |
| Helix Ravenswood, LLC | Ravenswood 10 | J | 25.0 | 21.2 | 27.0 | 16.1 | 20.3 | 5/1/2023 (R) | 2022 Q3 |
| National Grid | Glenwood GT 03 (3) | K | 55.0 | 54.7 | 71.5 | 54.1 | 66.6 | N/A | |
| National Grid | Northport GT (9) | K | 16.0 | 13.8 | 18.0 | 8.3 | 12.7 | 05/01/2023 | |
| National Grid | Port Jefferson GT 01 (9) | K | 16.0 | 14.1 | 18.4 | 13.0 | 15.3 | 05/01/2023 | |
| National Grid | Shoreham 1 (3) | K | 52.9 | 48.9 | 63.9 | 46.0 | 50.7 | N/A | |
| National Grid | Shoreham 2 (3) | K | 18.6 | 18.5 | 23.5 | 16.7 | 21.3 | N/A (11) | 2025 Q1 |
| Astoria Generating Company, L.P. | Astoria GT 01 | J | 16.0 | 15.7 | 20.5 | 13.8 | 18.0 | 5/1/2025 (R) | 2022 Q4 |
| Consolidated Edison Co. of NY, Inc. | 59 St. GT 1 (10) | J | 17.1 | 15.4 | 20.1 | 13.9 | 17.4 | 05/01/2025 | |
| NRG Power Marketing, LLC | Arthur Kill GT 1 (10) | J | 20.0 | 16.5 | 21.6 | 12.4 | 16.1 | 05/01/2025 | |
| Astoria Generating Company, L.P. | Gowanus 2-1 through 2-8 (5) | J | 160.0 | 152.8 | 199.6 | 142.2 | 182.5 | 05/01/2025 | |
| Astoria Generating Company, L.P. | Gowanus 3-1 through 3-8 (5) | J | 160.0 | 146.8 | 191.7 | 140.2 | 180.1 | 05/01/2025 | |
| Astoria Generating Company, L.P. | Narrows 1-1 through 2-8 (5) | J | 352.0 | 309.1 | 403.6 | 288.3 | 372.5 | 05/01/2025 | |
| | Prior to Summer 2022 | | 112.0 | 92.6 | 120.3 | 78.0 | 112.2 | | |
| | Prior to Summer 2023 | | 1047.8 | 943.9 | 1189.9 | 828.7 | 1083.2 | | |
| | Prior to Summer 2025 | | 725.1 | 656.3 | 857.1 | 610.8 | 786.6 | | |
| | Total | | 1884.9 | 1692.8 | 2167.3 | 1517.5 | 1982.0 | | |

Notes
1. MW values are from the 2025 Load and Capacity Data Report except where the 2025 Load and Capacity Data Report lists 0 MW for CRIS and/or Capability. For those instances, previous Load and Capacity Data Report MW values are used.
2. Dates identified by generators in their DEC Peaker Rule compliance plan submittals for transitioning the facility to Retired, Blackstart, or will be out-of-service in the summer ozone season or the date in which the generator entered (or proposed to enter) Retired (R) or Mothball Outage (MO) or the date on which the generator entered ICAP Ineligible Forced Outage (IIFO).
3. In the original compliance plan submittals to the DEC in early 2020, the plan for this unit was to install water injection by May 2023. In June 2021, National Grid Generation amended their compliance plan to eliminate the water injection upgrade with a scheduled retirement on or before May 2023. In August 2021, Long Island Power Authority (LIPA) submitted notification to the DEC, per part 227-3 of the peaker rule, stating that this unit is needed for reliability which allowed the generator to operate until at least May 1, 2025. Subsequently, in September 2024, LIPA submitted another notification to the DEC extending these units to operate until at least May 1, 2027 for reliability purposes. In October 2025, National Grid Generation amended its DEC Peaker Rule compliance plan submittal to again plan to install water injection equipment to comply with the emissions requirements for these units. National Grid Generation states in their October 2025 compliance plan submittal that the target in-service date for the water injection equipment is May 2027.
4. Long Island Power Authority (LIPA) has submitted notfications to the DEC per part 227-3 of the peaker rule stating that these units are needed for reliability allowing these units to operate until at least May 1, 2025. Due to the future nature of these units being operated only as designated by the operator as an emergency operating procedure the NYISO will continue to plan for these units be unavailable starting May 2023.
5. In their initial compliance plan submittals in response to the DEC Peaker Rule, these units indicated they would be out-of-service during the ozone season (May through September). In November 2023 the NYISO identified the need to temporarily retain these units until permanent solutions are in place, for an initial period of up to two years (May 2027). In July 2025 these units submitted their generator deactivation notice to retire in July 2026. These generator retirements for these units were evaluated in the 2025 Quarter 3 STAR. The IIFO of Gowanus 3-6, Narrows 2-1, and Narrows 2-7 were evaluated in the 2025 Quarter 2 STAR.
6. This unit was evaluated in a stand-alone generator deactivation assessment prior to the creation of the Short-Term Reliability Process.
7. Unit operating as a load modifier through September 2026.
8. In March 2024, Central Hudson submitted an update to its DEC peaker compliance plan to extend the retirement date of Coxsackie GT until December 31, 2025 until a permanent Transmission and Distribution solution to local non-BPTF transmission security issues is completed. At the April 7, 2025 TPAS/ESPWG, Central Hudson presented an LTP update including a delay of the retirement of the Coxsackie GT until May 2026. At the December 3, 2025 TPAS/ESPWG, Central Hudson presented in LTP update which continues to identify the retirement of the Coxsackie GT in May 2026.
9. On May 24, 2023 National Grid notified the New York State Public Service Commission that these units have been classified as black-start only units and are no longer subject to NYISO dispatch.
10. Unit no longer subject to NYISO dispatch and is used for local reliability only.
11. In October 2025 this unit rescinded its Generator Deactivation Notice, but the Generator is not currently participating in the ISO-Administered Markets.
12. The retirement for this unit was evaluated in the 2023 Q3 STAR. This unit retired on October 14, 2023.

#### Generator Return-to-Service

There are no generators that have returned to service beyond those included in the 2024 RNA.

#### Generator Additions

There are generation additions beyond those included in the 2024 RNA. A list of generator additions, including updates to planned commercial operation dates compared to the 2024 RNA is provided in Appendix C.

The NYISO continues to monitor the status of the planned Empire Wind and Sunrise Wind offshore wind projects, considering the December 22, 2025, orders by the Bureau of Ocean and Energy Management (BOEM) to suspend all ongoing activities.

#### Additional Generation Updates

At the March 27, 2024 meeting of the Management Committee, several changes were approved that impact the level of Installed Capacity resources are eligible to provide starting with the Summer 2026 Capability Period. These changes were made as part of the Modeling Improvements for Capacity Accreditation project – Correlated Derates. The Correlated Derates project addresses issues identified in Potomac Economics' Q3 2022 State of the Market Report as "functionally unavailable capacity." Specifically, (1) ambient water-related deratings for steam units, (2) humidity-adjustments for combined and simple cycle combustion turbines, and (3) emergency-only capacity that may not be reliably available in real-time (CLR's). These updated requirements are reflected in the NYISO ICAP manual and the Market Services Tariff Section 5. Overall, these changes reduce the expected DMNC for several generators. Due to the deactivations evaluated in this STAR within New York City and Long Island, the NYISO has proactively accounted for the reduction in summer capability of 110 MW in New York City and 200 MW in Long Island rather than waiting for the publication of the updates in the 2026 Gold Book. The NYISO continues to evaluate additional changes in DMNC in Zones A through I. These MW reductions reflect the expected impacts to DMNC on resources impacted by the rule changes.

### Demand Assumptions

This assessment recognizes that there is a range of possibilities for demand driven by uncertainties in key assumptions, such as population and economic growth, energy efficiency, installation of behind-the-meter renewable energy resources, and electric vehicle adoption and charging patterns that are captured in the 2025 Gold Book with changes in Zone K. Certain load projects in Zone K, which were included in the expected weather Gold Book forecasts have been removed from the model based on status updates regarding these load projects provided by LIPA.

The 2025 Gold Book includes three coincident demand forecasts: Lower Demand, Baseline, and Higher Demand. Each of these forecasts contains differing inputs on economic, electrification, and large load assumptions, but the weather conditions are the same across each of these forecast which are summarized in Appendix C (Figure 23 and Figure 24). The behind-the-meter (BTM) solar, BTM distributed generation, and energy storage forecasts are consistent across all forecasts. Further details of the Higher Demand and Lower Demand forecasts are summarized as follows:

- **Higher Demand –** The Higher Demand forecast is developed to broadly reflect levels of heating electrification and EV adoption commensurate with the achievement of New York's policy targets. However, the Higher Demand forecast does not include the full potential of peak-mitigating factors, such as managed EV charging and other flexible load and efficiency measures. The Higher Demand forecast assumes additional large load growth beyond that included in the baseline forecast. The Higher Demand econometric and EV and building electrification forecasts assume an increasing population and number of households over the duration of the forecast horizon, and stronger than expected economic growth.
- **Lower Demand –** The Lower Demand forecast assumes a slower EV adoption rate with a greater share of managed charging and a lower saturation of electric heating than the baseline forecast. Lower Demand forecast assumes reduced large load growth and weaker than expected economic growth relative to the baseline forecast.

The result of the differences in the forecasts is that the Higher Demand and Lower Demand forecasts produce lower and upper bounds around the baseline forecast. Figure 5 through Figure 8 provide visual depictions of the three forecasts for the summer peak for Lower Hudson Valley, New York City, Long Island, and Statewide. The NYISO also includes an assessment of the Lower Hudson Valley, New York City, and Long Island localities non-coincident peak in the identification of bulk system generator deactivation reliability needs.

One key assumption in this STAR is that cryptocurrency mining and hydrogen production large loads will be flexible during system peak demand conditions. This assumption, based on communications with load developers and recent operating experience, results in up to approximately 685 MW of large load reduction during the summer and winter peak periods by 2026. The trend of large load development, and their operating characteristics, requires continuous monitoring as they enter service. The NYISO will continue to coordinate with load developers and Transmission Owners.

Additional details of the demand forecasts are provided in Appendix C.

**Figure 5: Lower Hudson Valley Demand Forecasts (2025 Gold Book)**

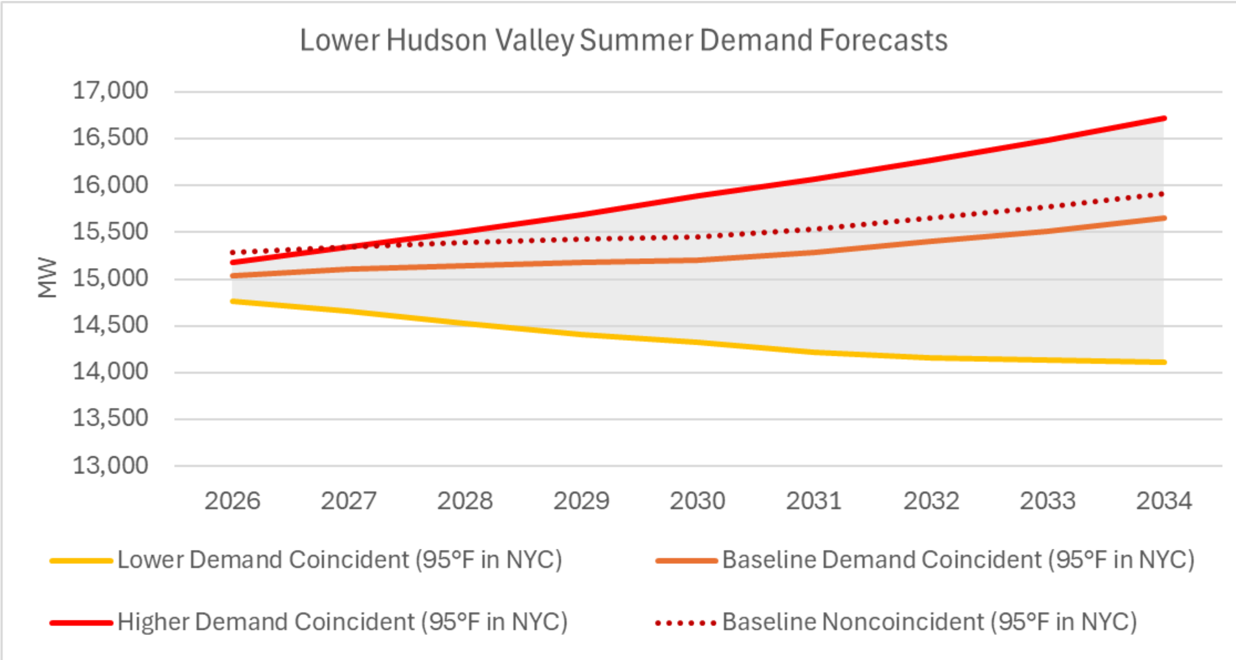



**Figure 6: New York City Demand Forecasts (2025 Gold Book)**

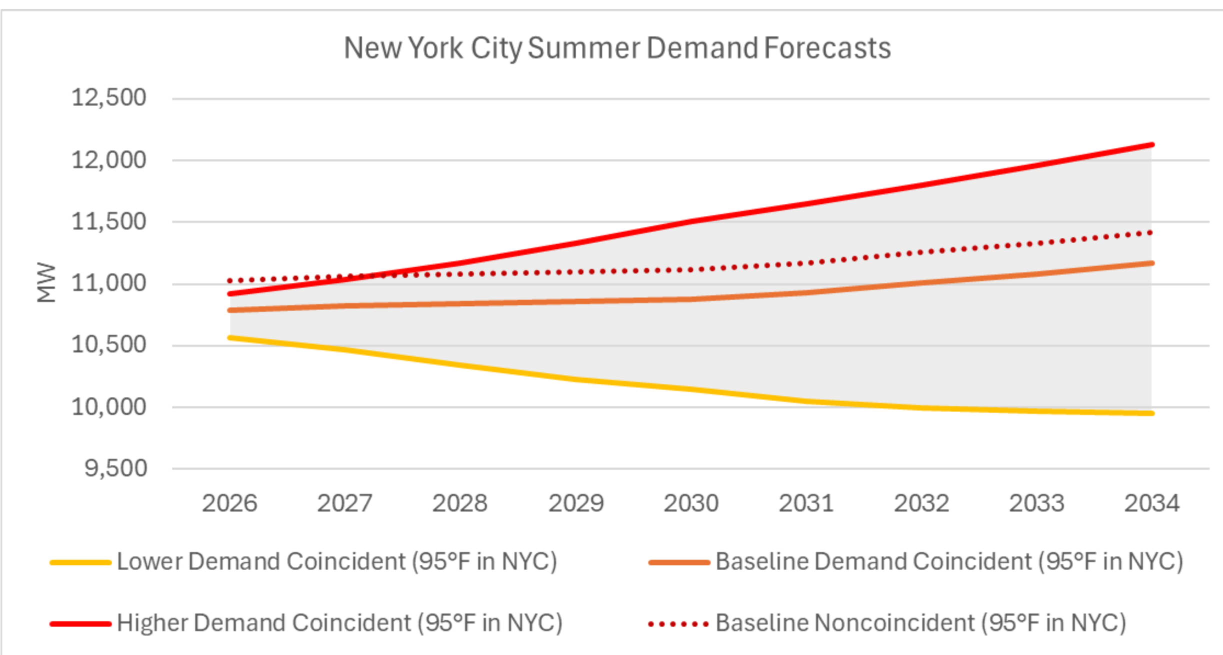


**Figure 7: Long Island Demand Forecasts (2025 Gold Book)**

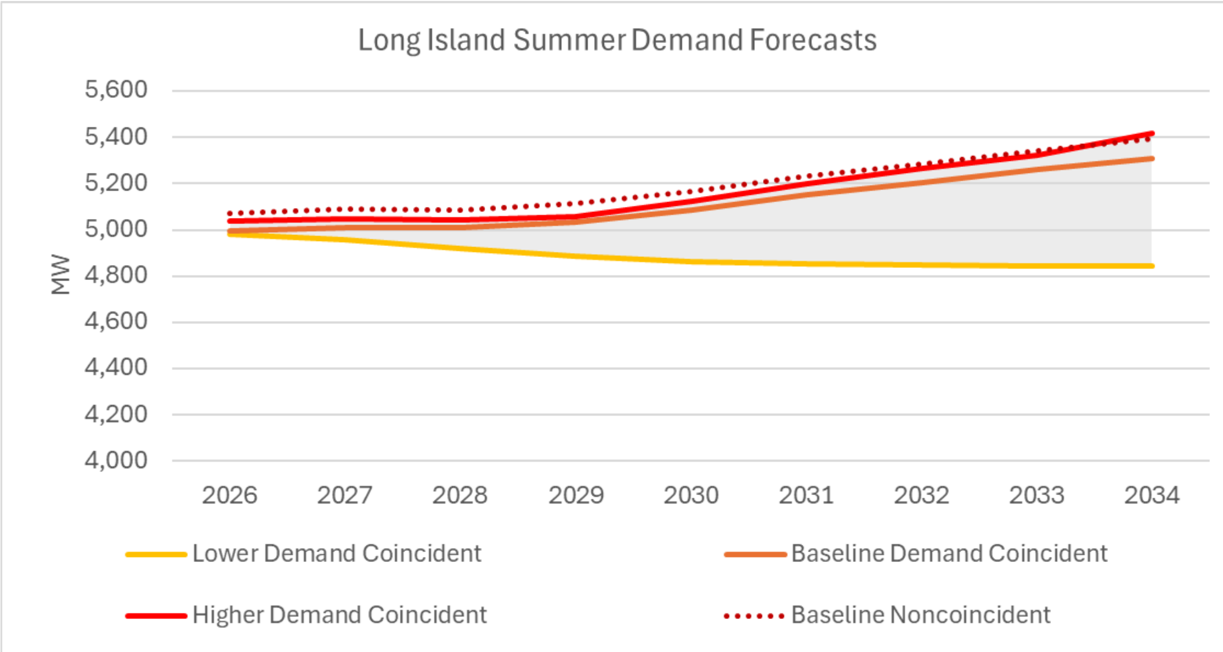
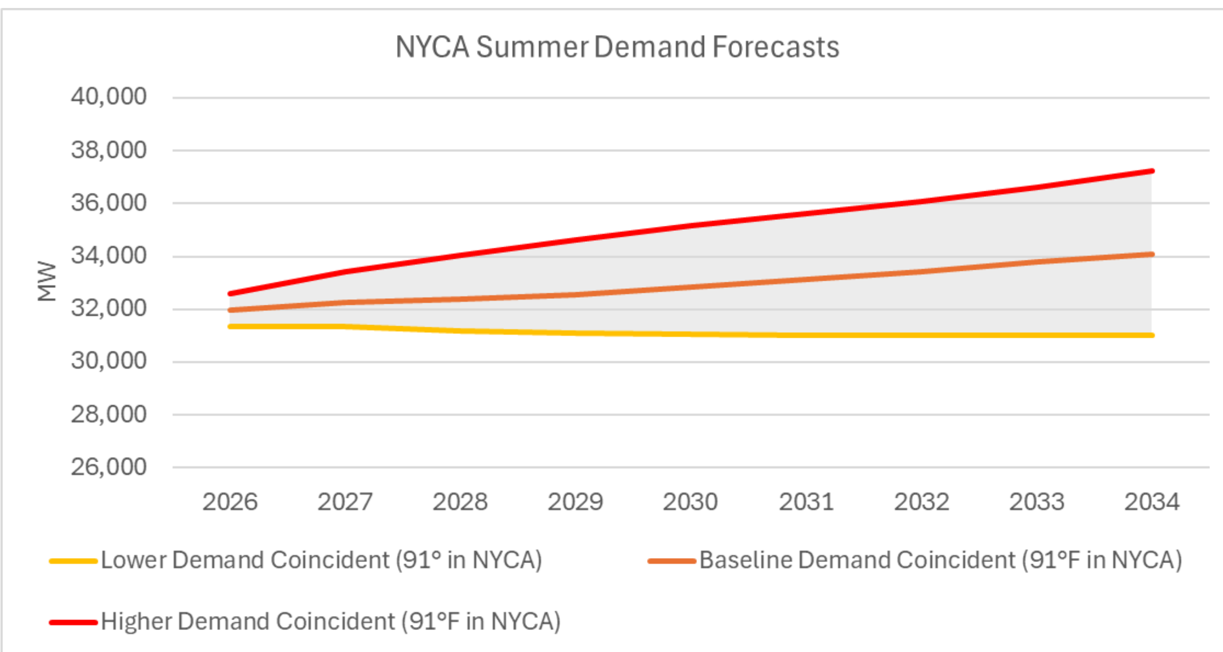



**Figure 8: NYCA Demand Forecasts (2025 Gold Book)**



## Transmission Assumptions

### Existing Transmission

The transmission assumptions utilized in this assessment are similar to those used for the 2024 RNA. Figure 9 lists the existing transmission outage assumptions.

**Figure 9: Transmission Assumptions**

| From | To | kV | ID | Out-of-Service Through | |
|---|---|---|---|---|---|
| | | | | Prior STAR | Current STAR |
| Marion | Farragut | 345 | B3402 | Long-Term | |
| Marion | Farragut | 345 | C3403 | Long-Term | |
| Plattsburgh (1) | Plattsburgh | 230/115 | AT1 | 9/2026 | |
| Stolle Rd | Stolle Rd | 115 | T11-52 | 12/2025 | In-service |
| Station 23 | Station 42 | 115 | 920 | 12/2025 | In-service |
| E13th Street | | 345/69 | BK17 | - | 6/2027 |

Notes

(1) A spare transformer is placed in-service during the outage

### Proposed Transmission

Changes to firm projects in the Transmission Owners' Local Transmission Owner Plans ("LTPs") are captured in Section VII of the 2025 Gold Book.

Compared to the 2024 RNA, there are no changes to assumed firm transmission facilities, as captured in Section 7 of the 2025 Gold Book. Details of the proposed transmission assumptions included in the 2024 RNA are provided in Appendix C. Except for the projects listed in Figure 32 in Appendix C, all firm transmission plans captured in the 2025 Gold Book are included.

# Findings

Grid reliability is determined by assessing transmission security and resource adequacy. Transmission security is the ability of the electric system to withstand disturbances, such as electric short circuits or unanticipated loss of system elements, without involuntarily disconnecting firm load. Resource adequacy is the ability of electric systems to supply the aggregate electrical demand and energy requirements of customers, accounting for scheduled and reasonably expected unscheduled outages of system elements.

As explained below, this assessment continues to observe the deficiencies identified in the 2025 Quarter 3 STAR and that the scope, scale, and nature of these deficiencies are unchanged from the needs specified in the NYISO's November 2025 solution solicitation. This STAR does not identify any new Short-Term Reliability Process Needs.

## Resource Adequacy Assessments

Resource adequacy is the ability of the electric system to supply the aggregate electrical demand and energy requirements of the firm load at all times, considering scheduled and reasonably expected unscheduled outages of system elements. The NYISO performs resource adequacy assessments on a probabilistic basis to capture the random nature of system element outages. If a system has sufficient transmission and generation, the probability of an unplanned disconnection of firm load is equal to or less than the system's standard, which is expressed as a loss of load expectation ("LOLE"). Consistent with the NPCC and NYSRC criterion, the New York State bulk power system is planned to meet an LOLE that, at any given point in time, is less than or equal to an involuntary firm load disconnection that is not more frequent than once in every 10 years, or 0.1 event days per year.

This assessment finds that the planned system through the study period meets the resource adequacy criterion. Details about the resource adequacy study assumptions are provided in Appendix D.

## Transmission Security Assessments

Transmission security is the ability of the power system to withstand disturbances, such as electric short circuits or unanticipated loss of system elements, and continue to supply and deliver electricity. The analysis for the transmission security assessment is conducted in accordance with NERC Reliability Standards, NPCC Transmission Design Criteria, and the NYSRC Reliability Rules. Transmission security is assessed deterministically with potential disturbances being applied without concern for the likelihood of the disturbance in the assessment. These disturbances (single-element and multiple-element contingencies) are categorized as the design criteria contingencies, which are explicitly defined in the reliability criteria. The impacts resulting from applying these design criteria contingencies are assessed to determine whether thermal loading, voltage or stability violations will occur. In addition, the NYISO performs a short circuit analysis to determine if the system can clear faulted facilities reliably under short circuit conditions. The NYISO's "Guideline for Fault Current Assessment"[12] describes the methodology for that analysis.

Transmission security analysis includes the assessment of various combinations of credible system conditions intended to stress the system. As transmission security analysis is deterministic, these various credible combinations of system conditions are evaluated throughout the study period to identify reliability needs. Intermittent generation is represented based on expected output during the modeled system conditions.[13]

Transmission security margins are included in this assessment to identify plausible changes in conditions or assumptions that might adversely impact the reliability of the system. The transmission security margin is the ability to meet load plus losses and system reserve (*i.e.*, total capacity requirement) using NYCA generation, interchange, and including temperature-based generation derates (total resources). This assessment is performed using a deterministic approach through powerflow simulations combined with post-processing spreadsheet-based calculations.[14] For the transmission security margin assessment, margins are evaluated for the statewide system margin, as well as Lower Hudson Valley, New York City, and Long Island localities. This evaluation will identify a BPTF reliability when the margin is less than zero under expected weather, normal transfer criteria conditions for the Lower Hudson Valley, New York City, and Long Island localities. Additional information regarding reliability risks due to various uncertainties such as weather and climate, economic development, or federal and state regulatory and policy adoptions are provided in the 2025-2034 CRP.

For the purposes of identifying reliability needs on the BPTF using transmission security margin calculations, thermal generation MW capability is considered available based on NERC five-year class averages for the relevant type of unit.[15] Derates for thermal generation are included due

[12]Attachment I of Transmission, Expansion, and Interconnection Manual.

[13]The RNA assumptions matrix is posted with the April 18, 2024 TPAS/ESPWG meeting materials, which are available here,

[14] At its June 23, 2022, meeting, the NYISO Operating Committee approved revisions to the Reliability Planning Process Manual that reflect the use of transmission security margins and other enhancements.

[15] The NERC five-year class average EFORd data is available here. NERC class average derating factors used in the STAR do not have a mechanism for excluding 9300 events (generator outages due to transmission system problems). *See* further discussion in Oct. 7, 2024 ICAP/MIWG/PRLWG presentation.

to the aging fleet without expected replacement, while the share of intermittent, weather dependent generation is growing.

#### Steady State Assessment

In the NYISO's evaluation of the BPTF, one voltage violation and two thermal overloads are observed. The identified issues do not result in a Short-Term Reliability Process Need, as they are addressed by modifications to planned system changes or consideration of known operational behavior. No other steady-state transmission security related needs were observed under other system conditions.

The first steady-state transmission security issue identified for the study period under expected summer peak conditions is a thermal violation on the Oakdale 345/115/34.5 kV transformer and Oakdale – North Endicott 115 kV transmission line. The violation occurs under N-1-1 conditions for contingency combinations that result in the loss of the Oakdale – Westover 115 kV and Oakdale – Northside 115 kV transmission lines. This overload is observed as early as summer 2026 and is addressed by the reconfiguration of the Oakdale 345 and 115 kV system along with a second Oakdale 345/115 kV transformer, which facilities are planned to be completed by winter 2030. Prior to completion of this project, NYSEG will utilize an interim operating procedure to address this overload. With the proposed interim load shed operating procedure and the local transmission plans, the NYISO will not solicit for solutions to address these issues but will continue to track the development of the local plans in the quarterly tracking process.

The second steady-state transmission security issue identified for the study period under expected summer peak conditions is a voltage violation at the Oakdale 115 kV station in expected summer peak conditions. The violation occurs under N-1-1 conditions for contingency combinations that result in loss of 345/115 kV transformers along with one of the two 345 kV lines from Oakdale to Fraser or Watercure. NYSEG has two local transmission plans that help to address these issues. The first plan is a reconfiguration at the Frasier 115 kV station that provides stronger voltage support of the transmission system in the local area and is planned to be in service in summer 2027. The second local plan is a reconfiguration of the Oakdale 345 and 115 kV system and a second Oakdale 345/115 kV transformer, which are planned to be completed by winter 2030. Due to the observations in this STAR at Oakdale, NYSEG has proposed interim operating procedures including possible load shedding should the critical contingencies occur. With the proposed interim load shed operating procedure and the local transmission plans, the NYISO will not solicit for solutions to address these issues but will continue to track the development of the local plans in the quarterly tracking process.

The third steady-state transmission security issue identified for the study period under expected summer peak conditions is a thermal violation on the Moses AT3 230/115 kV transformer. This violation was first observed in the 2024 Quarter 3 STAR winter peak conditions and is impacted by the inclusion of Q1213 - St Lawrence Data and Agricultural Center in the 2025 Quarter 1 STAR. The violation occurs under N-1-1 conditions for contingency combinations that result in the loss of the other three Moses 230/115 kV transformers. This overload is observed as early as summer 2026 and is driven by the growth of the North Country Data Center ("NCDC") load and the addition of St Lawrence Data and Agricultural Center. This issue is addressed by the expected operational behavior of flexible large loads, which would reduce their electrical demand under peak conditions. In consideration of this expected flexibility, the thermal violation on the Moses AT3 230/115 kV transformer would not be observed. As such, there are no thermal criteria violations, and the NYISO will not solicit for solutions to address these issues. However, a reliability risk to note is that more than 2,000 MW of additional load has requested to interconnect in Zone D downstream of the Moses 230/115 kV transformers. The NYISO will continue to monitor the status of these large loads and their anticipated operational behavior in future STARs.

#### Dynamics Assessment

No BPTF dynamic criteria violations were observed for this assessment. Additionally, no dynamic stability related non-BPTF generator deactivation reliability needs were observed for this assessment.

#### Short Circuit Assessment

No BPTF short-circuit criteria violations were observed in this assessment. Additionally, no short-circuit non-BPTF generator deactivation reliability needs were observed in this assessment.

### Transmission Security Margin Assessment

For the transmission security margin assessment, "tipping points" are evaluated for the Lower Hudson Valley, New York City, and Long Island localities as applicable to the identification of needs as the analysis is based on established Reliability Criteria. In the Lower Hudson Valley and Long Island localities, the BPTF system is designed to remain reliable in the event of two non-simultaneous outages (N-1-1). In the Con Edison service territory, the 345 kV transmission system and specific portions of the 138 kV transmission system are designed to remain reliable and return to normal ratings after the occurrence of two non-simultaneous outages (N-1-1-0).

Consistent with the findings of the 2025 Quarter 3 STAR, this STAR continues to find that the New York City locality (Zone J) would be deficient in the summer through the entire five-year horizon without the completion and energization of future planned projects. This includes deficiencies on the BPTF and non-BPTF within Zone J. The future planned projects associated with New York City include:

- Gowanus-Greenwood 345/138 kV feeder – May 2026
- CHPE, 1,250 MW HVDC – May 2026
- Empire Wind, 816 MW offshore wind – July 2027
- Propel NY Public Policy Transmission Project – May 2030

Until these system plans within New York City are completed and demonstrate their planned power capabilities to address the identified reliability needs, the previously identified BPTF and non-BPTF deficiencies would persist without Gowanus and Narrows.

This STAR finds that the BPTF in the Long Island locality (Zone K) is deficient beginning in summer 2027 and continuing through the remaining five-year horizon, primarily driven by the deactivation of Pinelawn (82 MW nameplate) and the Far Rockaway GTs (121 MW nameplate total) evaluated in the 2025 Quarter 3 STAR, but is also impacted by the completion and energization of future planned projects including the Sunrise Wind (July 2027) along with the Propel NY Public Policy Transmission Project. In addition to the BPTF deficiency, in the 2025 Quarter 3 STAR LIPA also identified non-BPTF system deficiencies on the 69 kV system through the entire five-year horizon.

The NYISO performed "status quo" evaluations the prior to these system plans and other additional resources state-wide demonstrating their planned capabilities (approximately 4,400 MW of generation projects, as described in Figure 21 and Figure 22) during the planning horizon, while maintaining the assumption that demand grows as forecasted for expected weather, including large load development.

This STAR finds that the Lower Hudson Valley, New York City, and Long Island localities are deficient in the summer. Details are provided below.

#### New York City Transmission Security Margin

In the 2025 Quarter 3 STAR, the Gowanus and Narrows proposed generator retirement was evaluated to determine if there were any generator deactivation reliability needs.

This STAR observed no changes to the Generator Deactivation Reliability Need observed in the 2025 Quarter 3 STAR. The New York City locality (Zone J) would be deficient through the entire five-year horizon until system plans are completed (CHPE, Empire Wind, and Propel NY project) and demonstrate their planned power capabilities. While these planned projects are advancing in their development, the completion is subject to inherent risks commonly observed among large infrastructure projects that may impact timely completion and energization. Key challenges include permitting, material availability, construction complexities, and other unexpected factors.

The following table provides the magnitude and duration of the BPTF deficiency through the five-year study period under summer peak if system plans are not completed. Winter transmission security margins in Zone J remain positive throughout the five-year horizon. In the 2025 Quarter 3 STAR, the NYISO identified these deficiencies as Generator Deactivation Reliability Needs. Further, as these needs were observed within three years following the conclusion of the 365 days that follow the STAR start date, they were also identified as Near-Term Reliability Needs. In accordance with the DEC Peaker Rule, the Gowanus and Narrows generators may extend operation for up to an additional two years (until May 1, 2029) if the NYISO or Con Edison determine that the reliability need still exists and a permanent solution has been identified and is in the process of construction but not yet online. The DEC Peaker Rule, however, does not provide for the Peaker generators to continue operating after this date without meeting the emissions requirement.

New York City BPTF Deficiencies:

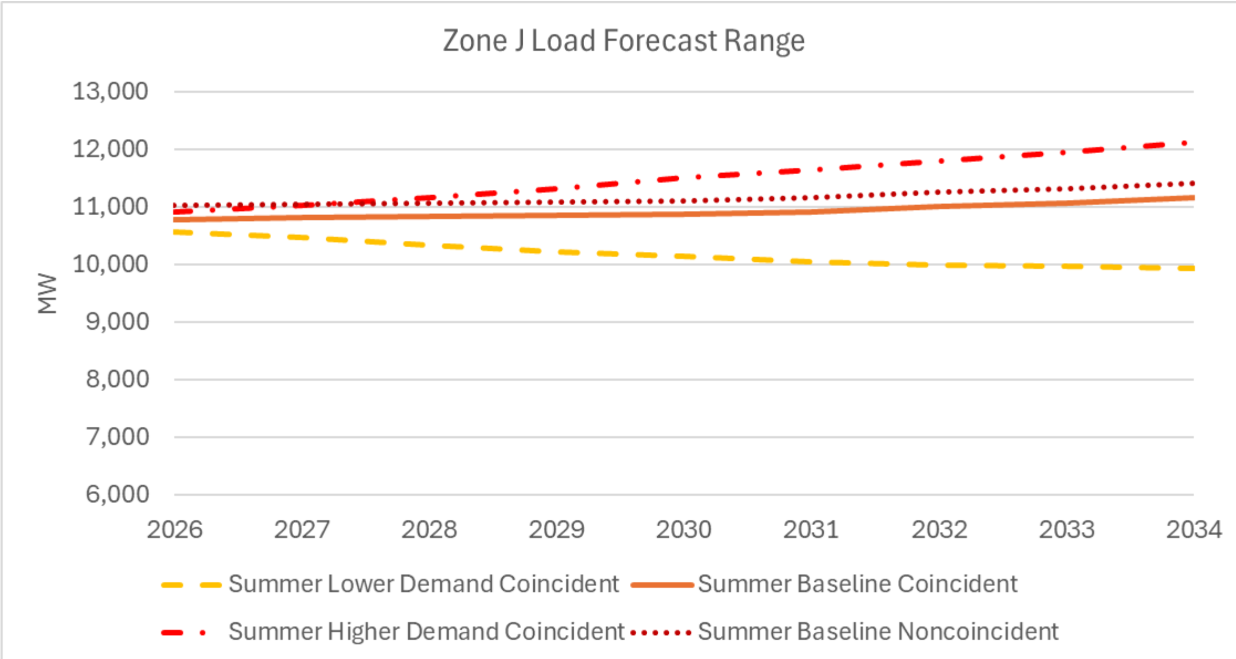
| Summer Peak | **2026** | **2027** | **2028** | **2029** | **2030** |
|---|---|---|---|---|---|
| MW Deficiency | 410-650 | 440-680 | 460-790 | 480-950 | 500-1,130 |
| Duration (hours) | 6-8 | 6-9 | 8-11 | 8-13 | 8-13 |
| MWh | 1,709-3,569 | 1,753-3,782 | 3,014-6,658 | 3,227-8,794 | 3,211-10,922 |

These deficiencies are driven by the deactivation of Gowanus 2 & 3 and Narrows 1 & 2 generators (672 MW nameplate total) in combination with other factors such as: the range in the demand forecasts based on expected weather, expected generator availability, transmission limitations, and risks associated with the availability of key future planned projects.

Once CHPE, Empire Wind, and Propel NY project enter service and demonstrate their planned power capabilities, the margins within Zone J would improve substantially, but the margin gradually erodes thereafter as expected demand for electricity grows. Even with the planned inclusion of these future planned projects entering service according to schedule and demonstrate their planned power capabilities, and assuming no other generators are unavailable, in 2029, Zone J could still remain deficient by 68 MW over 5 hours (871 MWh), which grows to 148 MW over 6 hours (1,249 MWh) in 2030. Beyond 2030, these deficiencies would be further exacerbated with increasing demand for electricity. Figure 11 and Figure 12 depict the reliability margins for Zone J without any planned projects ("status quo") and as planned. The New York City summer peak margin is shown in Figure 13 showing the reliability impact of the status quo as well as future planned generation and transmission projects that have met the Reliability Planning Process inclusion rules.

The range in the demand forecast driven by uncertainties in key assumptions, such as population and economic growth, energy efficiency, the installation of behind-the-meter renewable energy resources, and electric vehicle adoption and charging patterns as described in the 2025 Gold Book. The forecasted summer peak demand in New York City has a range of 460 MW in 2026 growing to 1,360 MW in 2030, primarily driven by assumptions in electrification of transportation and buildings. Details of the different load forecasts used in this STAR are shown below in Figure 10. The assumed available supply has also been adjusted to account for expected reductions of 110 MW in generators' dependable maximum net capability (DMNC) and 175 MW reduction in capacity sales from PJM.

**Figure 10: Zone J Load Forecast**



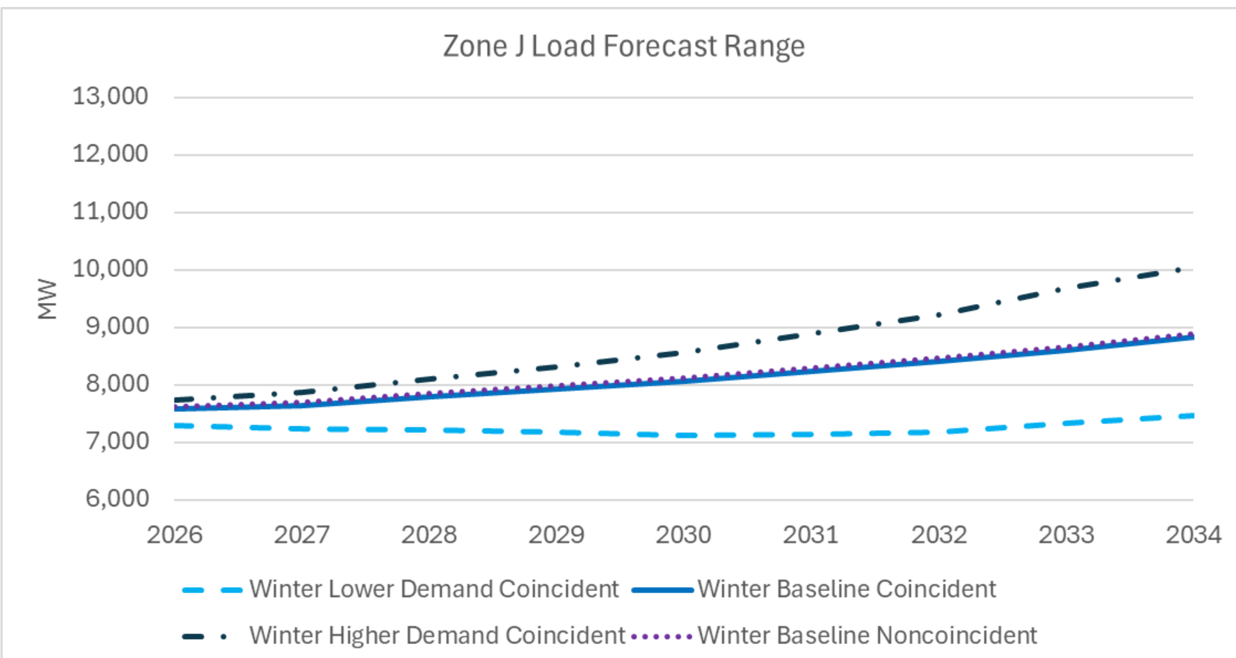



**Figure 11: Zone J Summer Transmission Security Margin**

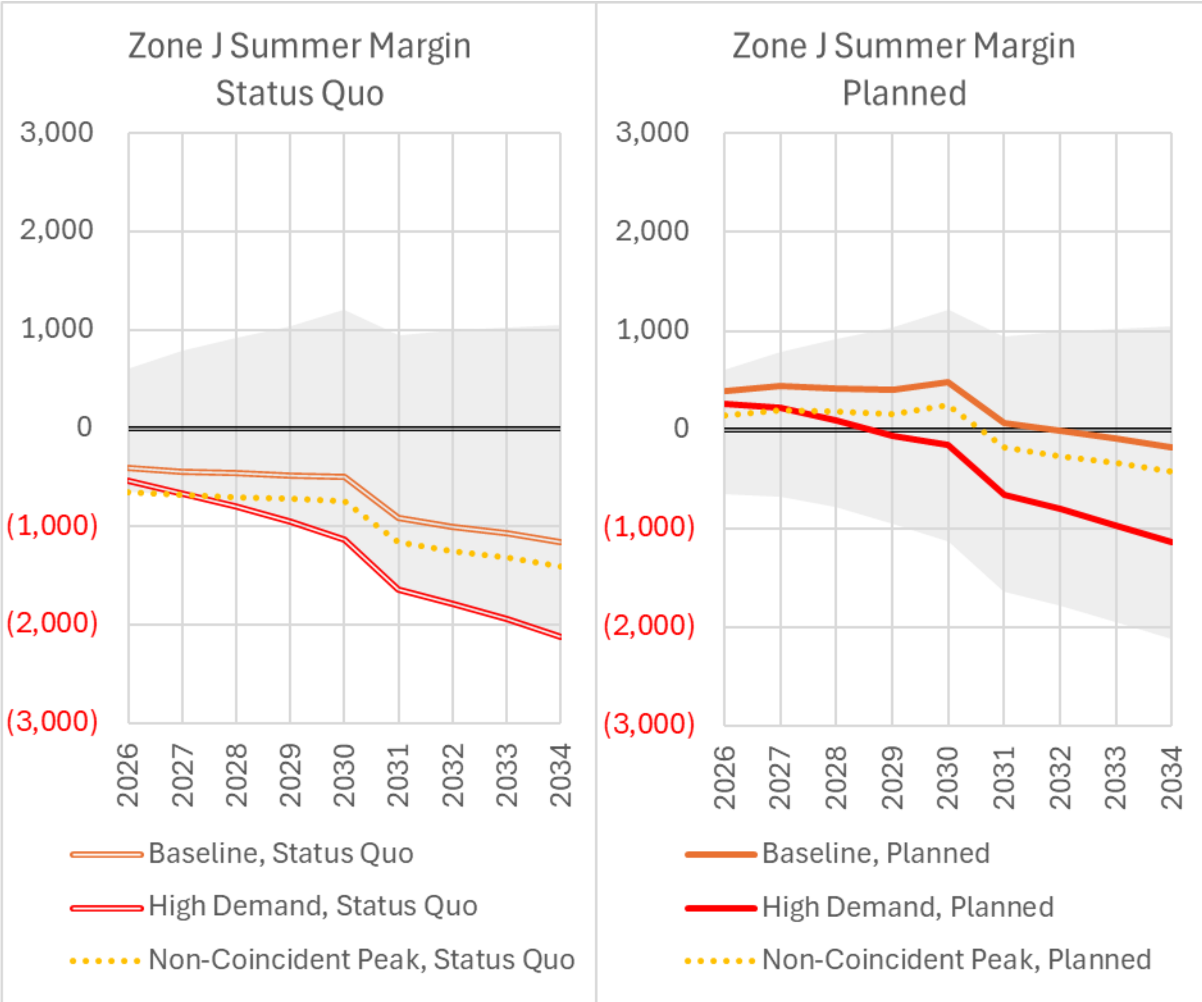


**Figure 12: Zone J Winter Transmission Security Margin**

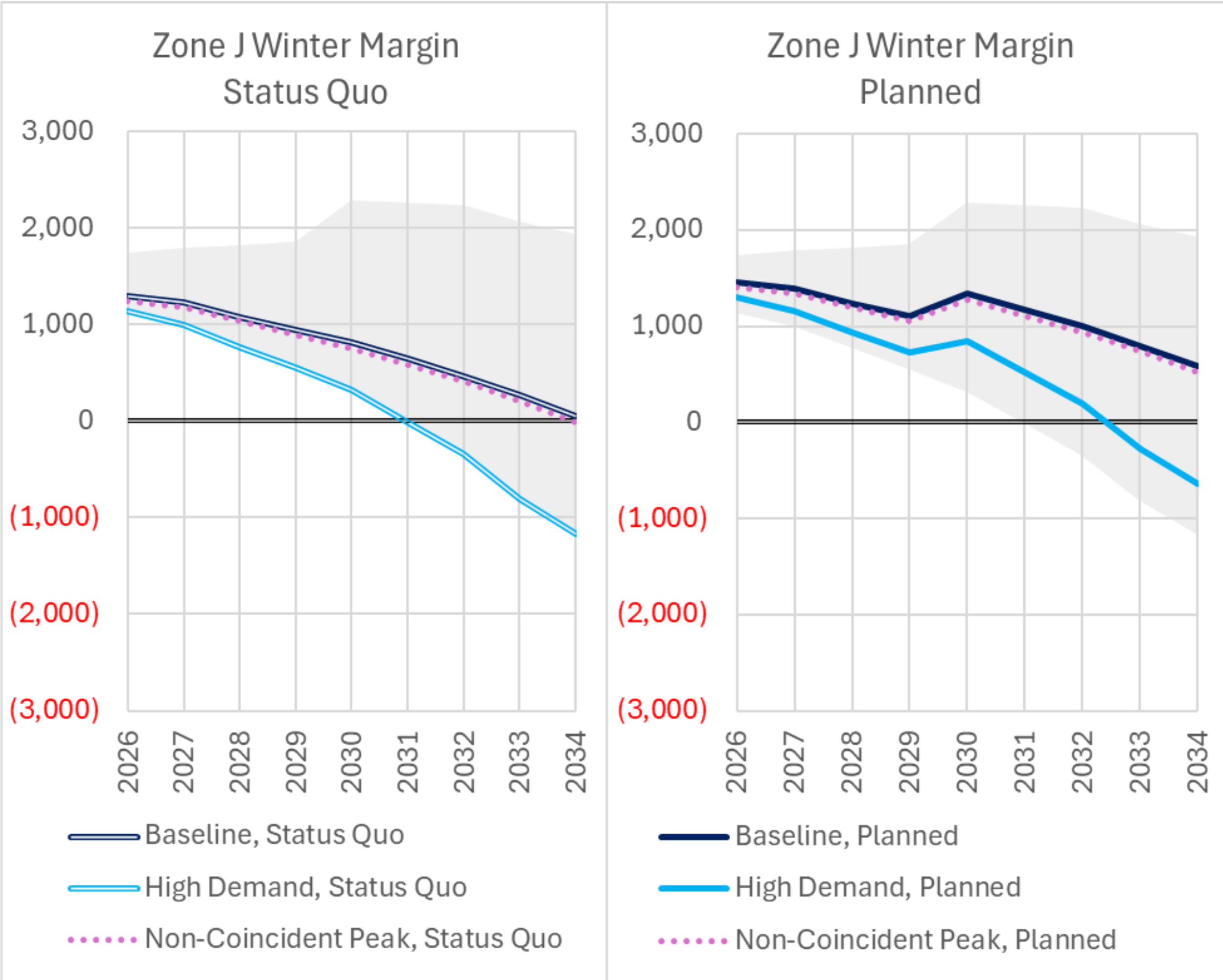
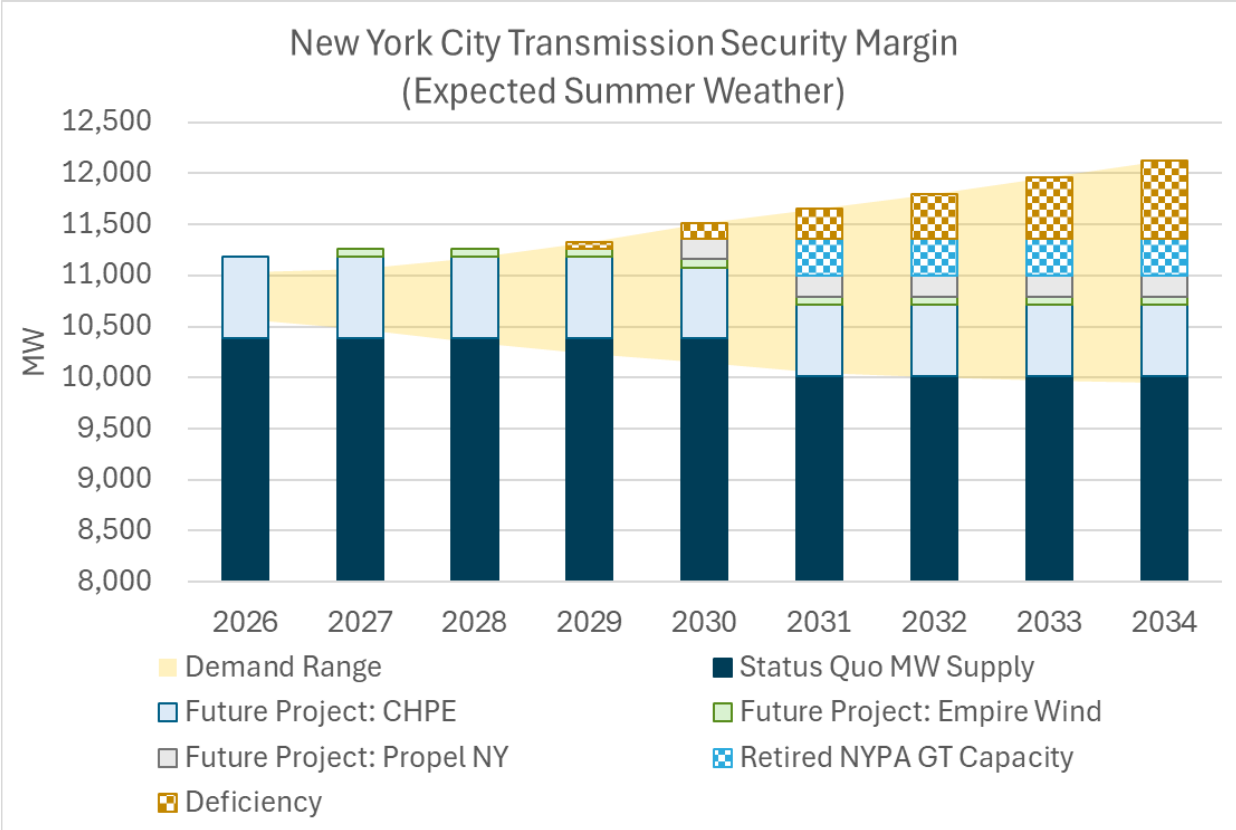


**Figure 13: Factors Affecting New York City Transmission Security Margin**




In the 2025 Quarter 3 STAR, Con Edison's non-BPTF system analysis found no Generator Deactivation Reliability Needs following the retirement of the Narrows and Gowanus generators. However, Con Edison projects a potential 250 MW deficiency starting in 2030 within the 345/138 kV BPTF New York City Transmission Load Area (TLA) assuming CHPE, Empire Wind, and Propel NY project entering service and demonstrate their planned power capabilities. Further information on the local reliability needs for the next decade were provided in Con Edison's 2025 Local Transmission Plan (LTP), discussed at a December 2025 stakeholder meeting.[16]

Additionally, the Lower Hudson Valley locality (Zones G-J) would be deficient by 195 MW over three hours (729 MWh) in summer 2030 without the completion and demonstration of the planned capabilities of the future planned projects associated with New York City and is also impacted by the BPTF Generator Deactivation Reliability Need identified in Zone K. As the need in the Lower Hudson Valley is an exacerbation of the need observed in New York City, it is also a Generator Deactivation Reliability Need, but it is not a Near-Term Reliability Need. This deficiency is further

[16] Con Edison's LTP update was presented to NYISO stakeholders at the December 3, 2025 TPAS/ESPWG meeting (here)

exacerbated through time without any additional capabilities added within the Lower Hudson Valley locality, which includes New York City.

#### Long Island Transmission Security Margin

In the 2025 Quarter 3 STAR, the Pinelawn Power 1 ("Pinelawn") (82 MW nameplate) and Far Rockaway Gas Turbine 1 and 2 ("Far Rockaway GTs") (121 MW nameplate total) completed their generator deactivation notice requiring the NYISO and LIPA to determine if there are any generator deactivation reliability needs. None of these units in the Long Island service territory are impacted by the DEC Peaker Rule.

In the 2025 Quarter 3 STAR, the NYISO found that Zone K is projected to be deficient without the completion and demonstration of planned capabilities of future projects. The following table provides the magnitude and duration of the BPTF deficiency through the five-year study period under summer peak if system plans are not completed. Winter transmission security margins in Zone K remain positive throughout the five-year horizon.

Long Island BPTF Deficiencies

| Summer Peak | **2026** | **2027** | **2028** | **2029** | **2030** |
|---|---|---|---|---|---|
| MW Deficiency | None | 34-111 | 34-111 | 58-136 | 110-189 |
| Duration | None | 1-3 | 2-3 | 2-3 | 3-3 |
| MWh | None | 34-156 | 139-363 | 177-407 | 320-557 |

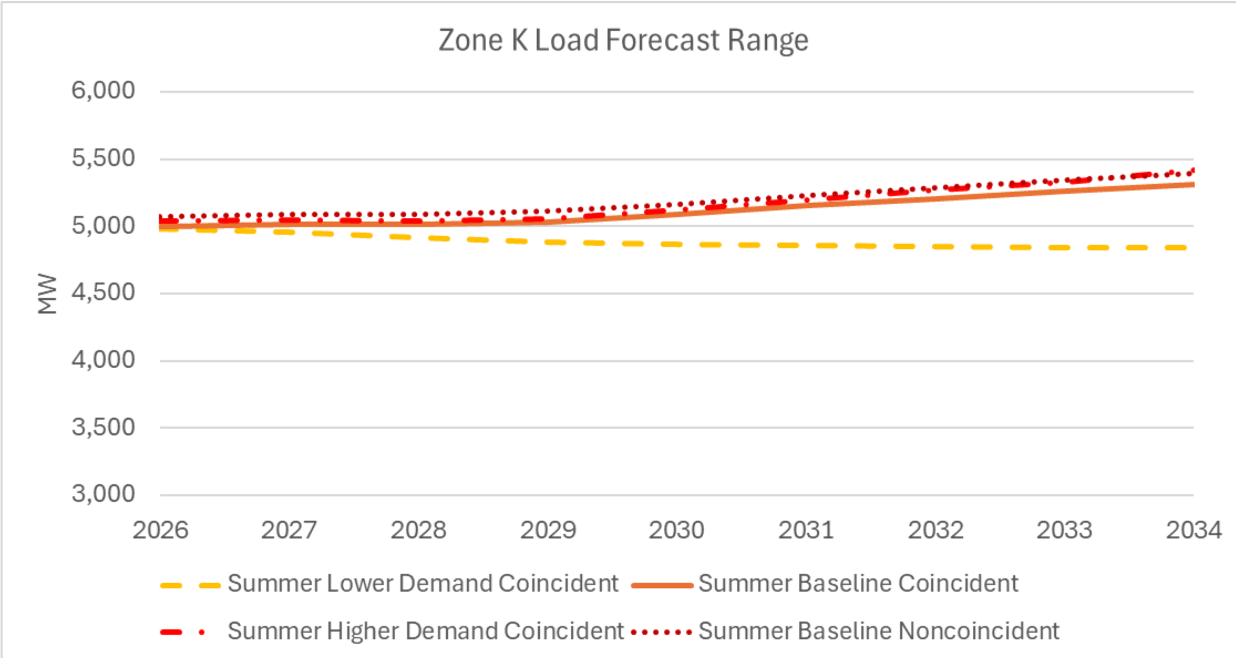
Once Sunrise Wind is delivering power as planned, the margins improve in summer 2028, followed by dramatic improvement in 2030 with the planned energization of the Propel NY project such that margins remain positive throughout the remainder of the planning horizon. However, even if these future planned projects are available according to current schedules, deficiencies under summer peak conditions are still observed in 2027. Specifically, with the planned projects available, the BPTF deficiency is 21 MW over 1 hour (21 MWh) in 2027. The Long Island summer peak margin is shown in Figure 17, which illustrates the reliability impact of the status quo as well as future planned generation and transmission projects that have met the Reliability Planning Process inclusion rules.

These deficiencies are driven by the deactivation of the Pinelawn and Far Rockaway generators in combination with other factors such as: the range in the demand forecasts based on expected weather, expected generator availability, transmission limitations, and risks associated with the availability of key future planned projects. Key inputs into these findings includes planned assumptions from the start of the STAR for external imports from the Cross-Sound Cable at in accordance with planned imports through early 2027, but starting in summer 2027 this import is assumed at 0 MW. In addition to being generator deactivation reliability needs, the 2025 Quarter 3 STAR also identified these deficiencies as near-term reliability needs. Winter margins in Zone K remain positive throughout the five-year horizon.

The range in the demand forecast driven by uncertainties in key assumptions, such as population and economic growth, energy efficiency, the installation of behind-the-meter renewable energy resources, and electric vehicle adoption and charging patterns as described in the 2025 Gold Book. The forecasted summer peak demand in Long Island has a range of 92 MW in 2026 growing to 302 MW in 2030, primarily driven by assumptions in the demand forecast. Details of the demand forecasts for expected weather used in the determination of the need in this STAR are shown below in Figure 14. The assumed available supply has also been adjusted to account for expected reductions of 200 MW in generators' DMNC based on the Correlated Derates explained above.

In October 2025, National Grid Generation amended its DEC Peaker Rule Compliance plan for Shoreham 1, Shoreham 2, and Glenwood GT 3 to install water injection by May 2027. This would allow these units to continue operation. Additionally, the assumed capacity purchases from ISO-NE into Zone K have been adjusted to account for a LIPA import of 288 MW from ISO-NE until April 2027, with zero flow scheduled thereafter. If these additional generation and import resources are available through the five-year horizon, the observed reliability need on the BTPF would be eliminated.

**Figure 14: Zone K Load Forecast Uncertainty**



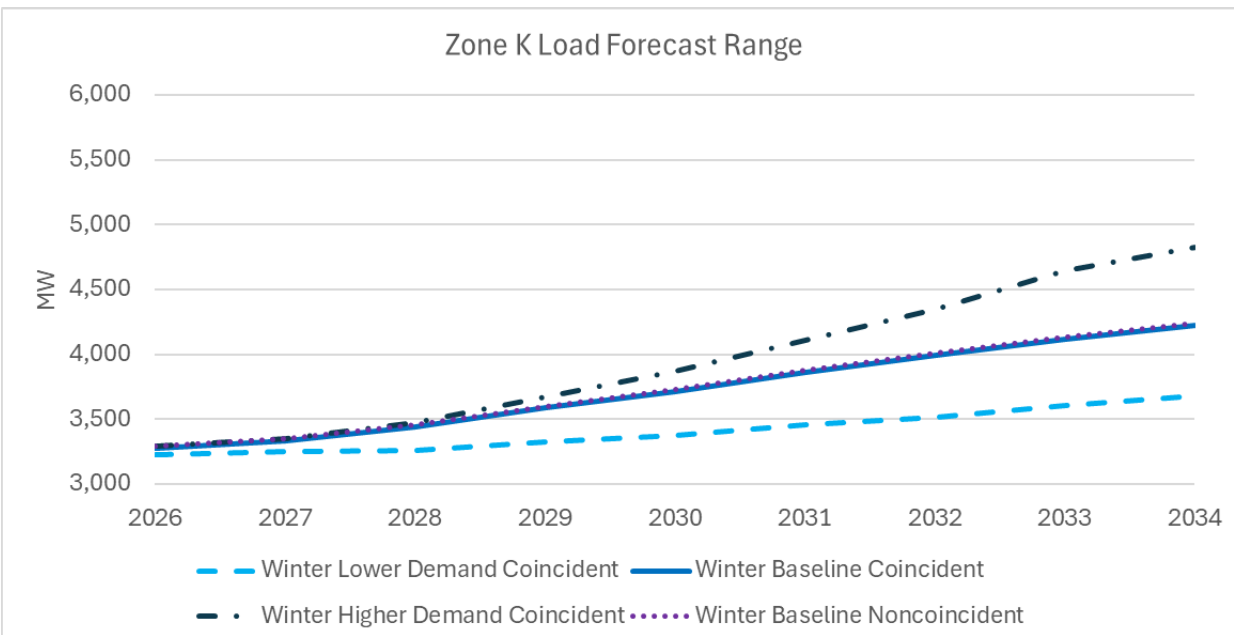



Figure 15: Zone K Summer Transmission Security Margin

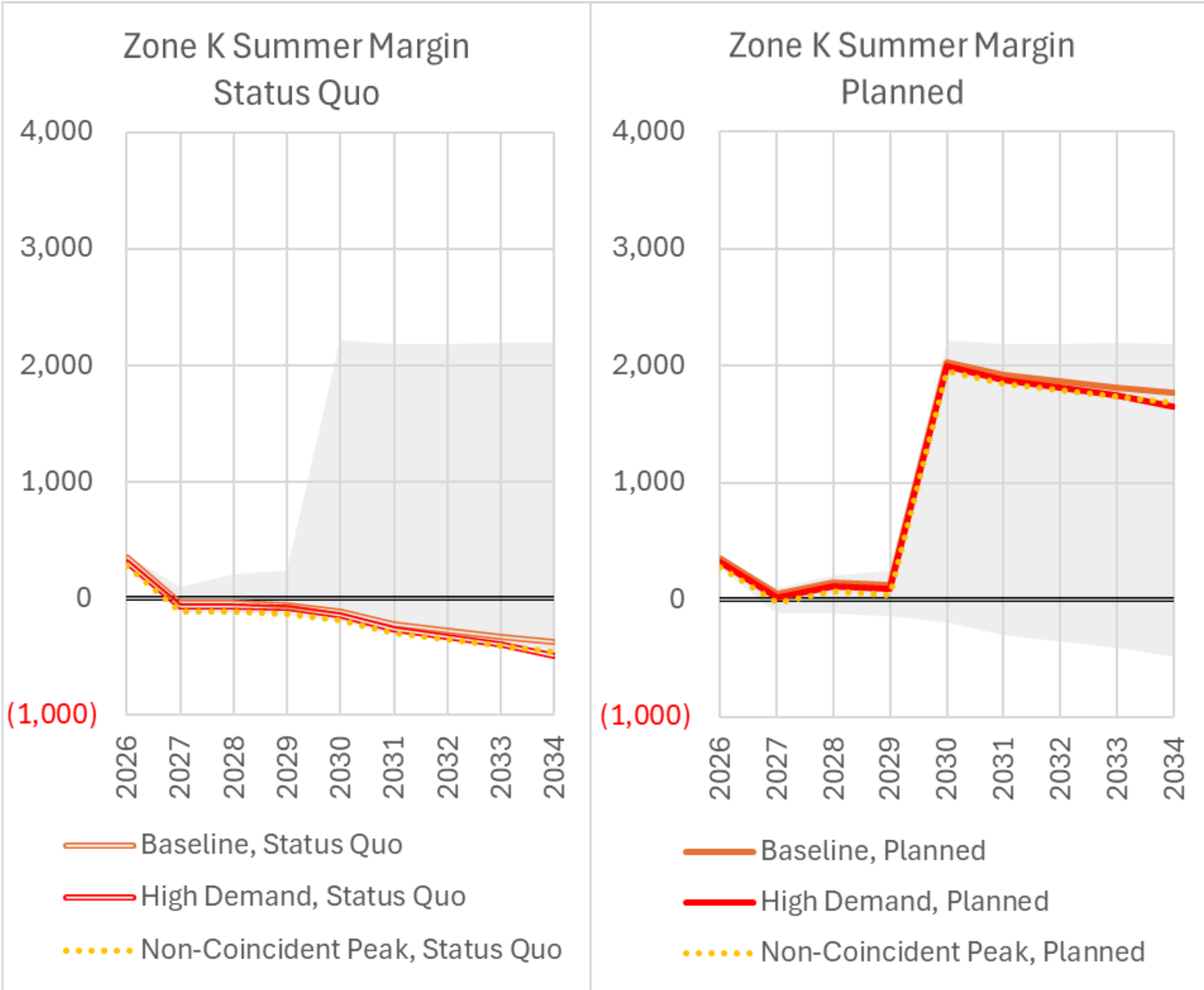


**Figure 16: Zone K Winter Transmission Security Margin**

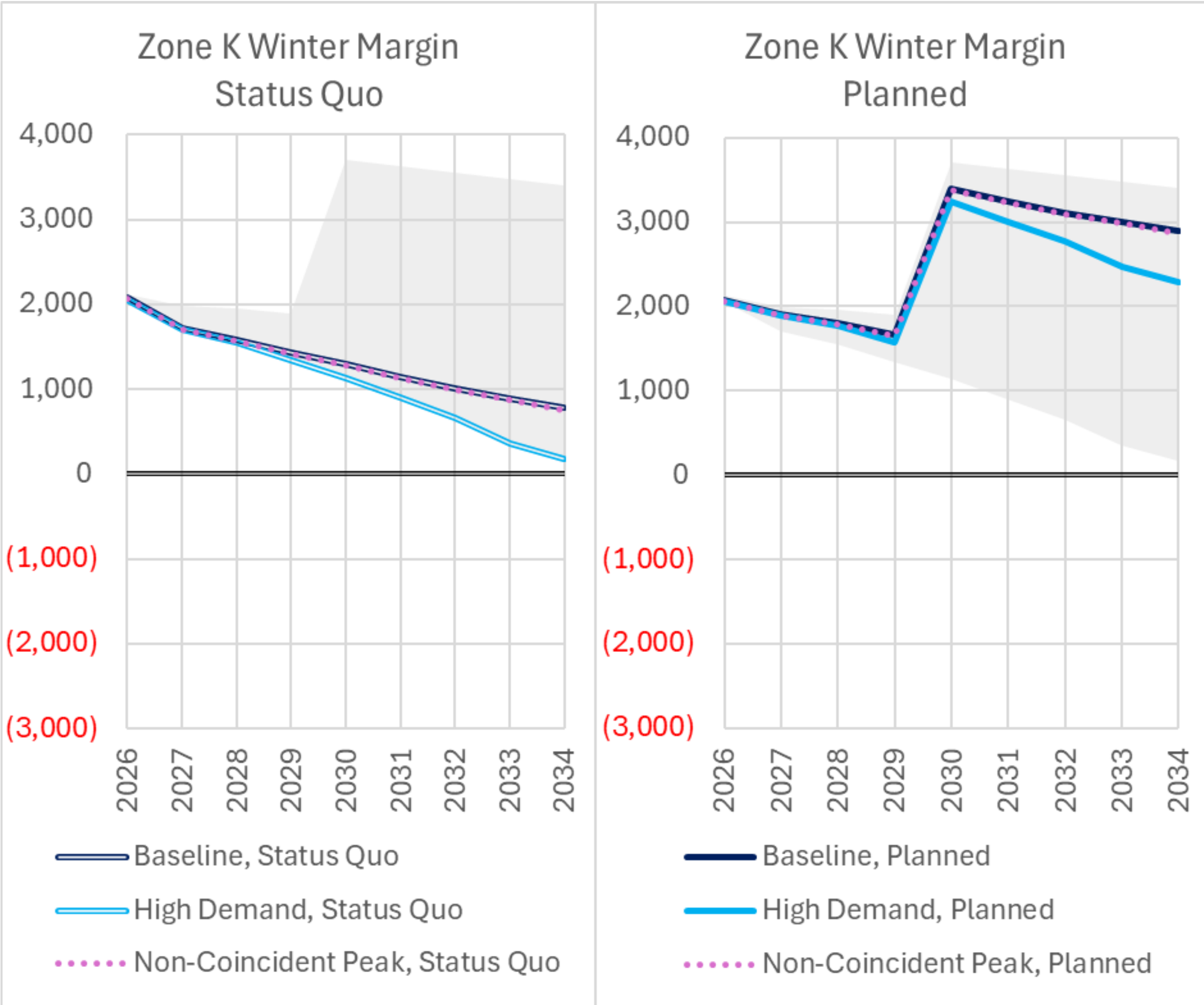
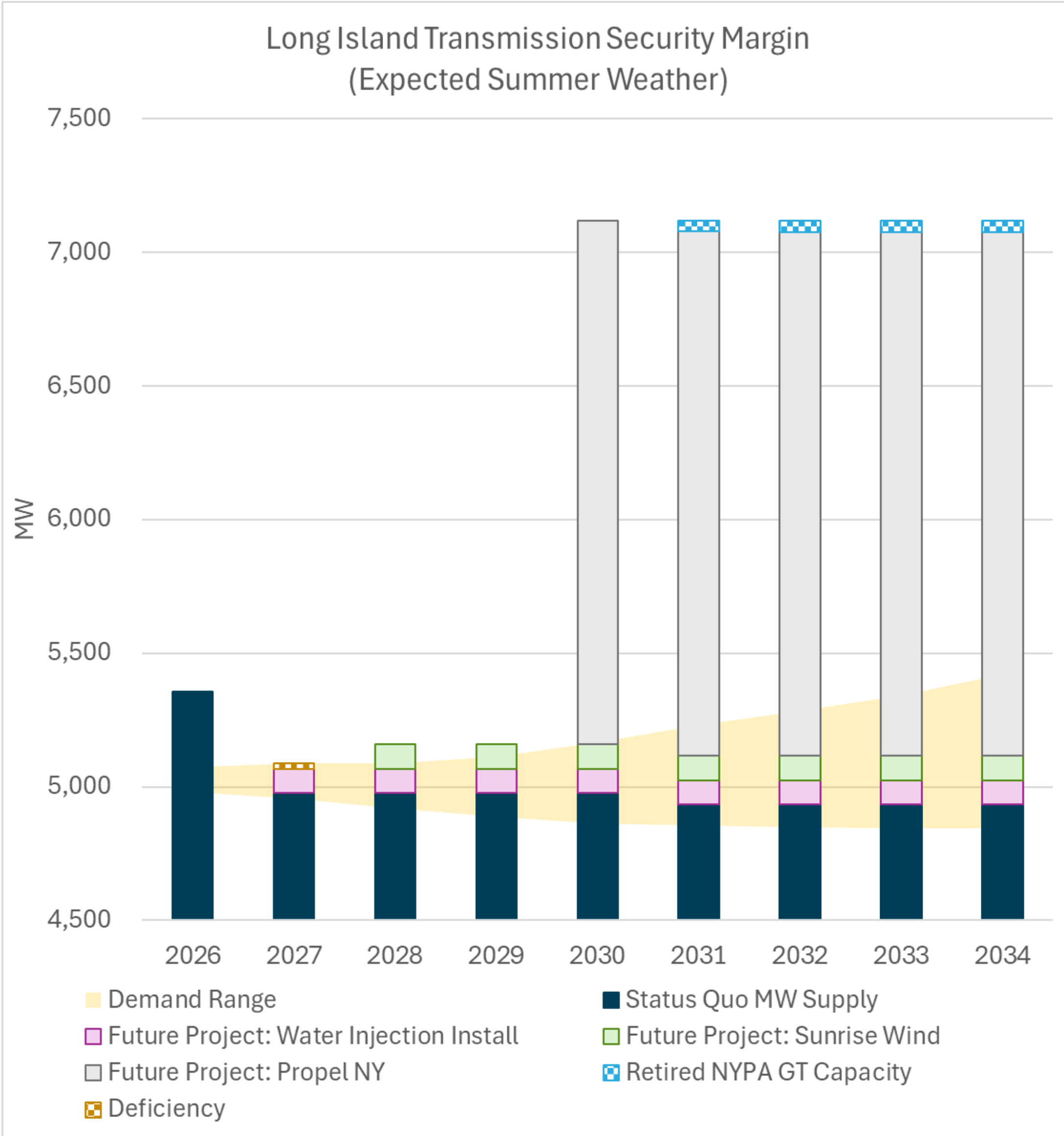


**Figure 17: Factors Affecting Long Island Transmission Security Margin**



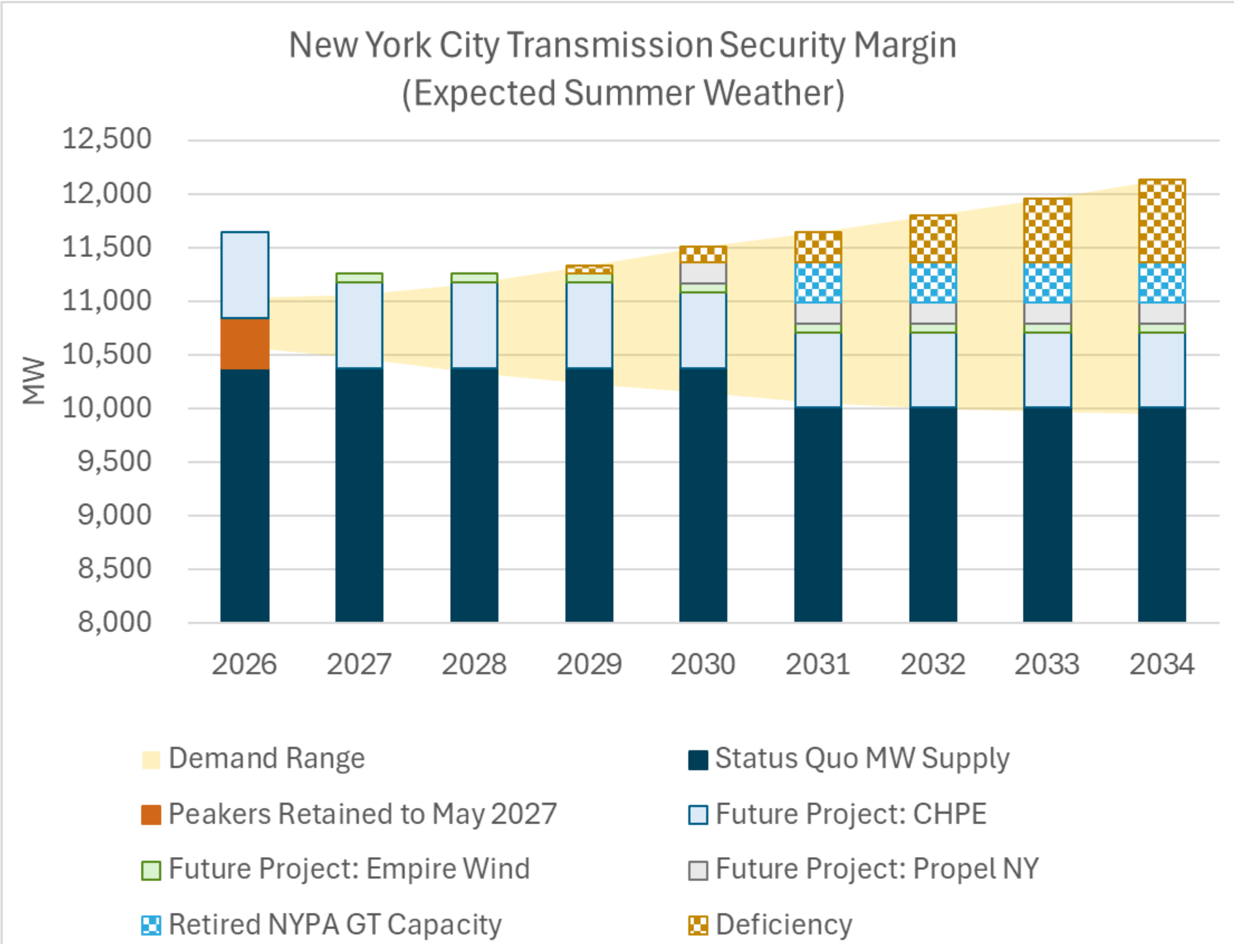
## Solutions to Previously Identified Short-Term Reliability Needs

On October 3, 2023, the NYISO received proposed solutions to the 2023 Quarter 2 STAR need within New York City. On November 20, 2023 the NYISO issued its Short-Term Reliability Process Report identifying the solution selected to address the 2025 New York City need.[17] The results of this determination were reviewed with stakeholders at the November 29, 2023 Management Committee meeting.[18] There were no viable and sufficient solutions submitted to the NYISO in response to its solicitation that met the need in 2025. The NYISO determined that temporarily retaining the peaker generators on the Gowanus 2 & 3 and Narrows 1 & 2 generators is necessary to address the need until a permanent solution is in place. The NYISO's designation of the Gowanus 2 & 3 and Narrows 1 & 2 generators as needed to maintain reliability allows their continued operation beyond May 2025 until the earlier of May 1, 2027, or the date a permanent solution is in place and a reliability need does not exist, consistent with the DEC Peaker Rule. The Gowanus 2 & 3 and Narrows 1 & 2 plant owner, Astoria Generating Company L.P., informed the NYISO that its generators are available to continue operation for so long as they are determined to be needed for reliability and are allowed to continue operating consistent with the Peaker Rule. With the continued operation of these peakers until the earlier of the date (a) the date a permanent solution (*i.e.,* CHPE) is in place and demonstrates dependable capacity supply during summer peak conditions or (b) May 2027, the need for the currently forecasted demand is addressed if CHPE is not delayed beyond 2026, as shown in Figure 18. The deactivation of Gowanus 2 & 3 and Narrows 1 & 2 units is assessed in the 2025 Quarter 3 STAR and the resulting impact to reliability criteria is discussed earlier in the report.

On November 10, 2025 the NYISO issued a solution solicitation to address the New York City and Long Island Generator Deactivation Reliability Needs observed in the 2025 Quarter 2 STAR. On January 9, 2026, the NYISO received the proposed solutions to these needs and is in the process of assessing the proposals.

[17] Short-Term Reliability Process Report: 2025 Near-Term Reliability Need, November 20, 2023 (here).
[18] Short-Term Reliability Process Report, Management Committee Meeting, November 29, 2023 (here).

**Figure 18: New York City Margin with Designated Peakers**




## Local Non-BPTF Reliability Assessment

National Grid evaluated the impact of the generator deactivations on their non-BPTF. The NYISO reviewed and verified the analysis performed by National Grid.

### National Grid Non-BPTF Generator Deactivation Assessment

For this STAR, National Grid performed a deactivation assessment to evaluate the reliability of the local non-BPTF system for the IIFO of Dahowa Hydro. National Grid did not identify Generator Deactivation Reliability Needs with the IIFO of Dahowa Hydro.

## Conclusions and Determination

Consistent with the analysis and explanations above, this assessment finds that the planned BPTF system through the study period meets applicable reliability criteria, other than the reliability needs previously identified in the 2025 Quarter 3 STAR as more fully detailed above. The local non-BPTF issue observed in the 2025 Quarter 3 STAR also continues to be observed. No Generator Deactivation Reliability Needs were identified by National Grid due to the IIFO of Dahowa Hydro.

This STAR observes no changes to the scope, scale, or nature of the Generator Deactivation Reliability Needs in New York City and Long Island included in the solution solicitation issued by the NYISO on November 10, 2025, following the 2025 Quarter 3 STAR. On January 9, 2026, the NYISO received the proposed solutions to these needs and is in the process of assessing the proposals. The NYISO will evaluate the proposed solutions and issue a Short-Term Reliability Process Report indicating NYISO's selection of a solution or combination of solutions, along with a reasoned explanation regarding why particular generation and/or transmission solutions were selected. If proposed solutions, either individually or in combination, are not viable or sufficient to meet the identified needs, interim solutions must be in place to keep the grid reliable. The NYISO's solution selection process is designed to ensure that executing a Reliability Must Run (RMR) Agreement with generators is a last resort to addressing a reliability need.

# Appendix A: List of Short-Term Reliability Needs

**New York City Generator Deactivation Reliability Needs**

Listed below are the Generator Deactivation Reliability Needs in the New York City locality in the solicitation letter for the 2025 Quarter 3 STAR.

BPTF Deficiencies:

| Summer Peak | **2026** | **2027** | **2028** | **2029** | **2030** |
|---|---|---|---|---|---|
| MW Deficiency | 650 | 680 | 790 | 950 | 1,130 |
| Duration (hours) | 8 | 9 | 11 | 13 | 13 |
| MWh | 3,569 | 3,782 | 6,658 | 8,794 | 10,922 |

The deficiency reported in the 2025 Quarter 3 STAR for the Lower Hudson Valley is primarily an exacerbation of the New York City BPTF Need and is also impacted by the BPTF Generator Deactivation Reliability Need identified in Zone K. Accordingly, the NYISO is not separately seeking solutions to address the deficiency for the Lower Hudson Valley beyond the solutions for the identified needs in Zones J and K. If there remains a deficiency in the Lower Hudson Valley following the solicitation and evaluation of proposed solutions to address the needs in Zones J and K, the NYISO would address it through the Reliability Planning Process.

#### Long Island Generator Deactivation Reliability Needs

Listed below are the Generator Deactivation Reliability Needs in the Long Island locality as detailed in the solicitation letter for the 2025 Quarter 3 STAR.

BPTF Deficiencies:

| Summer Peak | **2026** | **2027** | **2028** | **2029** | **2030** |
|---|---|---|---|---|---|
| MW Deficiency | None | 111 | 111 | 136 | 189 |
| Duration | None | 3 | 3 | 3 | 3 |
| MWh | None | 156 | 363 | 407 | 557 |

Non-BPTF Deficiencies (Far Rockaway Load Pocket)

| Summer Peak | **2026** | **2027** | **2028** | **2029** | **2030** |
|---|---|---|---|---|---|
| MW Deficiency | 61 | 68 | 74 | 80 | 72 |
| Duration | 13 | 14 | 15 | 15 | 14 |
| MWh | 505 | 658 | 736 | 813 | 649 |

# Appendix B: Short-Term Reliability Process Solution List

The Short-Term Reliability Process solution list and the status of these solutions is posted on the NYISO website at the following location:

https://www.nyiso.com/documents/20142/19556596/SolutionStatus-03092021.pdf/

# Appendix C: Summary of Study Assumptions

This assessment used the major assumptions included in the 2024 RNA, with the key updates noted below. Consistent with the NYISO's obligations under its tariffs, the NYISO provided information to stakeholders on the modeling assumptions employed in this assessment. Details regarding the 2024 RNA study assumptions were reviewed with stakeholders at the April 18, 2024, joint Electric System Planning Working Group ("ESPWG")/Transmission Planning Advisory Subcommittee ("TPAS") meeting. Details regarding the 2025 Quarter 4 STAR study assumptions were reviewed with stakeholders at the November 7, 2025, joint ESPWG/ TPAS meeting. The meeting materials are posted on the NYISO's website.[19] The figures below (Figure 19, Figure 20, Figure 21, and Figure 22) summarize the changes to generation, load, and transmission.

## Generation Assumptions

[19] Short-Term Assessment of Reliability: 2025 Q3 Key Study Assumptions, ESPWG/TPAS, November 7, 2025 (here). 2024 RNA Key Study Assumptions, ESPWG/TPAS, April 18, 2024 (here),

## Figure 19: Completed Generator Deactivations

| Owner/ Operator | Plant Name | Zone | Nameplate (MW) | CRIS (MW) Summer | CRIS (MW) Winter | Capability (MW) Summer | Capability (MW) Winter | Status | Deactivation Date (2) | STAR Evaluation (3) |
|---|---|---|---|---|---|---|---|---|---|---|
| International Paper Company | Ticonderoga (1) | F | 9.0 | 7.6 | 7.5 | 9.5 | 9.8 | I | 5/1/2017 | - |
| Helix Ravenswood, LLC | Ravenswood 2-4 | J | 42.9 | 39.8 | 50.6 | 30.7 | 41.6 | I | 4/1/2018 | - |
| | Ravenswood 3-1 | J | 42.9 | 40.5 | 51.5 | 31.9 | 40.8 | I | 4/1/2018 | - |
| | Ravenswood 3-2 | J | 42.9 | 38.1 | 48.5 | 29.4 | 40.3 | I | 4/1/2018 | - |
| | Ravenswood 3-4 | J | 42.9 | 35.8 | 45.5 | 31.2 | 40.8 | I | 4/1/2018 | - |
| Rockville Centre, Village of | Charles P Keller 07 | K | 2.0 | 2.0 | 2.0 | 1.9 | 1.9 | R | 3/1/2019 | - |
| Exelon Generation Company LLC | Monroe Livingston | B | 2.4 | 2.4 | 2.4 | 2.4 | 2.4 | R | 9/1/2019 | - |
| Innovative Energy Systems, Inc. | Steuben County LF | C | 3.2 | 3.2 | 3.2 | 3.2 | 3.2 | R | 9/1/2019 | - |
| Consolidated Edison Co. of NY, Inc | Hudson Ave 4 | J | 16.3 | 13.9 | 18.2 | 14.0 | 16.3 | R | 9/10/2019 | - |
| New York State Elec. & Gas Corp. | Auburn - State St | C | 7.4 | 5.8 | 6.2 | 4.1 | 7.3 | R | 10/1/2019 | - |
| Somerset Operating Company, LLC | Somerset | A | 655.1 | 686.5 | 686.5 | 676.4 | 684.4 | R | 3/12/2020 | - |
| Entergy Nuclear Power Marketing, LLC | Indian Point 2 | H | 1,299.0 | 1,026.5 | 1,026.5 | 1,011.5 | 1,029.4 | R | 4/30/2020 | - |
| Cayuga Operating Company, LLC | Cayuga 1 | C | 155.3 | 154.1 | 154.1 | 151.0 | 152.0 | R | 6/4/2020 | - |
| Entergy Nuclear Power Marketing, LLC | Indian Point 3 | H | 1,012.0 | 1,040.4 | 1,040.4 | 1,036.3 | 1,038.3 | R | 4/30/2021 | - |
| Helix Ravenswood, LLC | Ravenswood GT 11 | J | 25.0 | 20.2 | 25.7 | 16.1 | 22.4 | I | 12/1/2021 | 2022 Q1 |
| Helix Ravenswood, LLC | Ravenswood GT 1 | J | 18.6 | 8.8 | 11.5 | 7.7 | 11.1 | I | 1/1/2022 | 2022 Q1 |
| Freeport Electric | Freeport 1-4 | K | 6.0 | 4.4 | 4.4 | 4.5 | 5.0 | R | 5/1/2022 | - |
| Exelon Generation Company LLC | Madison County LF | E | 1.6 | 1.6 | 1.6 | 1.6 | 1.6 | I | 4/1/2022 | 2022 Q2 |
| Nassau Energy, LLC | Trigen CC | K | 55.0 | 51.6 | 60.1 | 38.5 | 51.0 | R | 7/15/2022 | 2022 Q2 |
| Consolidated Edison Co. of NY, Inc. | Hudson Ave 3 | J | 16.3 | 16.0 | 20.9 | 12.3 | 15.6 | R | 11/1/2022 | 2022 Q2 |
| Consolidated Edison Co. of NY, Inc. | Hudson Ave 5 | J | 16.3 | 15.1 | 19.7 | 15.3 | 18.6 | R | 11/1/2022 | 2022 Q2 |
| Astoria Generating Company, L.P. | Gowanus 1-1 through 1-8 | J | 160.0 | 138.7 | 181.1 | 133.1 | 182.2 | R | 11/1/2022 | 2022 Q2 |
| Astoria Generating Company, L.P. | Gowanus 4-1 through 4-8 | J | 160.0 | 140.1 | 182.9 | 138.8 | 183.4 | R | 11/1/2022 | 2022 Q2 |
| NRG Power Marketing LLC | Astoria GT 2-1 | J | 46.5 | 41.2 | 50.7 | 34.9 | 46.5 | R | 5/1/2023 | 2022 Q2 |
| NRG Power Marketing LLC | Astoria GT 2-2 | J | 46.5 | 42.4 | 52.2 | 34.3 | 45.6 | R | 5/1/2023 | 2022 Q2 |
| NRG Power Marketing LLC | Astoria GT 2-3 | J | 46.5 | 41.2 | 50.7 | 36.3 | 46.7 | R | 5/1/2023 | 2022 Q2 |
| NRG Power Marketing LLC | Astoria GT 2-4 | J | 46.5 | 41.0 | 50.5 | 32.5 | 45.4 | R | 5/1/2023 | 2022 Q2 |
| NRG Power Marketing LLC | Astoria GT 3-1 | J | 46.5 | 41.2 | 50.7 | 34.6 | 45.0 | R | 5/1/2023 | 2022 Q2 |
| NRG Power Marketing LLC | Astoria GT 3-2 | J | 46.5 | 43.5 | 53.5 | 35.7 | 45.3 | R | 5/1/2023 | 2022 Q2 |
| NRG Power Marketing LLC | Astoria GT 3-3 | J | 46.5 | 43.0 | 52.9 | 33.9 | 44.6 | R | 5/1/2023 | 2022 Q2 |
| NRG Power Marketing LLC | Astoria GT 3-4 | J | 46.5 | 43.0 | 52.9 | 34.9 | 45.5 | R | 5/1/2023 | 2022 Q2 |
| NRG Power Marketing LLC | Astoria GT 4-1 | J | 46.5 | 42.6 | 52.4 | 33.6 | 43.8 | R | 5/1/2023 | 2022 Q2 |
| NRG Power Marketing LLC | Astoria GT 4-2 | J | 46.5 | 41.4 | 51.0 | 34.3 | 44.3 | R | 5/1/2023 | 2022 Q2 |
| NRG Power Marketing LLC | Astoria GT 4-3 | J | 46.5 | 41.1 | 50.6 | 35.4 | 46.4 | R | 5/1/2023 | 2022 Q2 |
| NRG Power Marketing LLC | Astoria GT 4-4 | J | 46.5 | 42.8 | 52.7 | 35.2 | 44.1 | R | 5/1/2023 | 2022 Q2 |
| Helix Ravenswood, LLC | Ravenswood 10 | J | 25.0 | 21.2 | 27.0 | 16.1 | 20.3 | R | 5/1/2023 | 2022 Q3 |
| Helix Ravenswood, LLC | Ravenswood 01 | J | 18.6 | 8.8 | 11.5 | 7.7 | 11.1 | R | 10/14/2023 | 2023 Q3 |
| Helix Ravenswood, LLC | Ravenswood 11 | J | 25.0 | 20.2 | 25.7 | 16.1 | 22.4 | R | 10/14/2023 | 2023 Q3 |
| Astoria Generating Company, L.P. | Gowanus 3-6 | J | 20.0 | 17.6 | 23.0 | 16.4 | 20.4 | I | 7/14/2026 | 2025 Q2 |
| Astoria Generating Company, L.P. | Narrows 2-1 and 2-7 | J | 44.0 | 40.1 | 52.3 | 37.9 | 48.8 | I | 7/14/2026 | 2025 Q2 |
| Consolidated Edison Co. of NY, Inc. | 59 St. GT 1 (4) | J | 17.1 | 15.4 | 20.1 | 13.9 | 17.4 | R | 5/1/2025 | - |
| Western New York Wind Corp | Western NY Wind Power | B | 6.6 | 0.0 | 0.0 | 0.0 | 0.0 | R | 10/15/2023 | 2023 Q3 |
| Central Hudson Gas & Electric Corp. | South Cairo GT | G | 21.6 | 19.8 | 25.9 | 18.7 | 23.1 | R | 3/31/2024 | 2023 Q4 |
| Cubit Power One Inc. | Arthur Kill Cogen | J | 11.1 | 11.1 | 11.1 | 11.1 | 10.2 | I | 3/2/2024 | 2024 Q2 |
| NRG Power Marketing, LLC | Arthur Kill GT 1 (4) | J | 20 | 16.5 | 21.6 | 12.4 | 16.1 | R | 5/1/2025 | - |
| Eastern Generation, LLC | Astoria GT 01 | J | 16 | 15.7 | 20.5 | 13.8 | 17.6 | R | 5/1/2025 | 2024 Q3 |
| Madison Windpower, LLC | Madison Windpower | E | 11.6 | 11.5 | 11.5 | 11.6 | 11.6 | R | 5/1/2025 | 2025 Q1 |
| Casella Waste Systems, Inc | Hyland LFGE | B | 4.8 | 4.8 | 4.8 | 4.8 | 4.8 | I | 6/1/2025 | 2025 Q3 |
| | | Total | 4,591.5 | 4,200.2 | 4,526.8 | 3,997.5 | 4,366.4 | | | |

Notes
(1) Part of SCR program
(2) This table only includes units that have entered into IIFO (I) or have completed the generator deactivation process (R).
(3) "-" denotes that the generator deactivation was assessed prior to the creation of the Short-Term Reliability Process
(4) Unit no longer subject to NYISO dispatch and is used for local reliability only.

**Figure 20: Proposed Deactivations**

| Owner/ Operator | Plant Name (1) | Zone | Nameplate (MW) | CRIS (MW) | | Capability (MW) | | Status | Deactivation date (2) | STAR Evaluation |
|---|---|---|---|---|---|---|---|---|---|---|
| | | | | Summer | Winter | Summer | Winter | | | |
| Central Hudson Gas & Electric Corp. | Coxsackie GT | G | 21.6 | 21.6 | 26.0 | 19.7 | 22.7 | R | 12/31/2025 (3) | 2024 Q1 |
| MPH Cross Island Power, LLC | Pinelawn Power 1 | K | 82 | 78.0 | 78.0 | 73.6 | 76.5 | R | 11/1/2025 | 2025 Q3 |
| MPH Rockaway Peakers, LLC | Far Rockaway GT1 | K | 60.5 | 53.5 | 73.1 | 48.9 | 52.6 | R | 11/1/2025 | 2025 Q3 |
| MPH Rockaway Peakers, LLC | Far Rockaway GT2 | K | 60.5 | 55.4 | 75.7 | 55.7 | 59.0 | R | 11/1/2025 | 2025 Q3 |
| Astoria Generating Company, L.P. | Gowanus 2-1 through 2-8 | J | 160 | 152.8 | 199.6 | 142.2 | 182.5 | R | 7/14/2026 | 2025 Q3 |
| Astoria Generating Company, L.P. | Gowanus 3-1 through 3-8 (4) | J | 140 | 129.2 | 168.7 | 123.8 | 159.7 | R | 7/14/2026 | 2025 Q3 |
| Astoria Generating Company, L.P. | Narrows 1-1 through 2-8 (5) | J | 308 | 269.0 | 351.3 | 250.4 | 323.7 | R | 7/14/2026 | 2025 Q3 |
| Relevate ReDev Borrower II LLC | Dahowa Hydroelectric | F | 12.3 | 10.5 | 10.5 | 12.3 | 12.3 | IIFO | 9/1/2025 | 2025 Q4 |
| | | Total | 844.9 | 770.0 | 982.9 | 726.6 | 889.0 | | | |

Notes:

(1) This table includes units that have proposed to Retire or enter Mothball Outage and have a completed generator deactivation notice but have yet to complete the generator deactivation process.

(2) Date in which the generator proposed Retire (R) or enter Mothball Outage (MO)

(3) In March 2024, Central Hudson submitted an update to its DEC peaker compliance plan to extend the retirement date of Coxsackie GT until December 31, 2025 until a permanent transmission and distrubition solution to local non-BPTF transmission security issues is completed. At the April 7, 2025 TPAS/ESPWG, Central Hudson presented an LTP update including a delay of the retirement of the Coxsakie GT until May 2026.

(4) Does not include Gowanus GT 3-6.

(5) Does not include Narrows GT 2-1 and 2-7.

**Figure 21: Large Generation Additions**

| Proposed Project Inclusion: Large Generation | | | | | | | |
|---|---|---|---|---|---|---|---|
| Queue | Project Name | MW | Type | Zone | Proposed Date | | Included in Prior STAR |
| | | | | | Prior STAR | Current STAR | |
| 396 | Baron Winds Phase II | 117 | W | C | Dec-25 | | Yes |
| 571 | Heritage Wind, LLC | 200.1 | W | B | Sep-26 | | Yes |
| 596 | Alle Catt II Wind | 339.1 | W | A | Dec-26 | | Yes |
| 704 | Bear Ridge Solar | 100 | S | A | Apr-27 | | Yes |
| 720 | Trelinia Solar Energy Center | 80 | S | C | Apr-28 | | Yes |
| 721 | Excelsior Energy Center | 280 | S | A | Nov-26 | | Yes |
| 737 | Empire Wind 1 | 816 | W | J | Jul-27 | | Yes |
| 811 | Hecate Energy Cider Solar LLC | 500 | S | B | Dec-26 | **Jan-27** | Yes |
| 880 | Brookside Solar | 100 | S | D | May-28 | **Dec-27** | Yes |
| 883 | Garnet Energy Center, LLC | 200 | S | B | Apr-28 | | Yes |
| 950 | Hemlock Ridge Solar | 200 | S | B | May-27 | **Apr-28** | Yes |
| 1079 | Somerset Solar | 125 | S | A | Mar-27 | **Jun-28** | Yes |
| 766/987 | Sunrise Wind LLC | 924 | W | K | Jul-27 | | Yes |

**Figure 22: Small Generation Additions**

| Proposed Project Inclusion: Small Generation | | | | | | | |
|---|---|---|---|---|---|---|---|
| Queue | Project Name | MW | Type | Zone | Proposed Date | | Included in Prior STAR |
| | | | | | Prior STAR | Current STAR | |
| 545 | Sky High Solar | 20 | S | C | Jun-25 | **Dec-26** | Yes |
| 564 | Rock District Solar | 20 | S | F | Feb-27 | | Yes |
| 572 | Greene County 1 | 20 | S | G | May-25 | **Jun-27** | Yes |
| 573 | Greene County 2 | 10 | S | G | May-25 | **Jun-27** | Yes |
| 581 | Hills Solar | 20 | S | E | Dec-26 | | Yes |
| 584 | Dog Corners Solar | 20 | S | C | Apr-26 | | Yes |
| 586 | Watkins Rd Solar | 20 | S | E | Jul-26 | **Feb-27** | Yes |
| 590 | Scipio Solar | 18 | S | C | Dec-26 | | Yes |
| 591 | Highview Solar | 20 | S | C | Feb-25 | **Nov-26** | Yes |
| 592 | Niagara Solar | 20 | S | A | Dec-26 | | Yes |
| 734 | Ticonderoga Solar | 20 | S | F | Dec-26 | | Yes |
| 804 | KCE NY 10 | 20 | ES | A | Oct-26 | | Yes |
| 827 | Arthur Kill Energy Storage 1 | 15 | ES | J | Sep-25 | **Dec-25** | Yes |
| 828 | Valley Solar | 20 | S | C | Nov-24 | **Jan-27** | Yes |
| 832 | CS Hawthorn Solar | 20 | S | F | Dec-26 | | Yes |
| 833 | Dolan Solar | 20 | S | F | Dec-26 | | Yes |
| 848 | Fairway Solar | 20 | S | E | Mar-25 | **May-28** | Yes |
| 855 | NY13 Solar | 20 | S | F | Jun-25 | **Jun-27** | Yes |
| 865 | Flat Hill Solar | 20 | S | E | Dec-25 | | Yes |
| 885 | Grassy Knoll Solar | 20 | S | E | Dec-25 | **May-28** | Yes |
| 1003 | Clear View Solar | 20 | S | C | Dec-25 | | Yes |
| 1015 | Somers Solar, LLC | 20 | S | F | Dec-26 | | Yes |
| 1047 | Millers Grove Solar | 20 | S | E | Dec-26 | | Yes |

*All projects have CRIS.

## Demand Assumptions

The 2025 Quarter 4 STAR uses the demand forecasts for the study years consistent with the 2025 Gold Book for expected weather conditions with changes to Zone K to account for the removal of certain load projects. Details on the demand forecasts utilized for determining reliability needs are provided below.

**Figure 23: Summer Coincident Peak Demand Forecasts**

| Summer Coincident Peak Demand Forecast (MW) | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Year | | A | B | C | D | E | F | G | H | I | J | K | NYCA |
| 2026 | Low Demand | 2,840 | 1,842 | 2,559 | 839 | 1,287 | 2,240 | 2,262 | 615 | 1,316 | 10,570 | 4,980 | 31,350 |
| | Baseline | 2,943 | 1,854 | 2,568 | 1,042 | 1,298 | 2,255 | 2,304 | 620 | 1,320 | 10,790 | 4,996 | 31,990 |
| | High Demand | 3,120 | 1,995 | 2,633 | 1,045 | 1,308 | 2,274 | 2,307 | 625 | 1,324 | 10,920 | 5,039 | 32,590 |
| 2027 | Low Demand | 2,820 | 1,837 | 2,613 | 934 | 1,271 | 2,243 | 2,261 | 613 | 1,317 | 10,470 | 4,961 | 31,340 |
| | Baseline | 2,936 | 1,846 | 2,639 | 1,171 | 1,293 | 2,275 | 2,331 | 625 | 1,327 | 10,820 | 5,012 | 32,275 |
| | High Demand | 3,214 | 2,124 | 2,831 | 1,287 | 1,305 | 2,299 | 2,339 | 627 | 1,333 | 11,040 | 5,046 | 33,445 |
| 2028 | Low Demand | 2,802 | 1,827 | 2,716 | 931 | 1,256 | 2,206 | 2,258 | 610 | 1,318 | 10,340 | 4,946 | 31,210 |
| | Baseline | 2,925 | 1,834 | 2,737 | 1,173 | 1,293 | 2,265 | 2,344 | 625 | 1,336 | 10,840 | 5,011 | 32,383 |
| | High Demand | 3,423 | 2,135 | 3,034 | 1,297 | 1,312 | 2,284 | 2,366 | 628 | 1,343 | 11,170 | 5,041 | 34,033 |
| 2029 | Low Demand | 2,785 | 1,816 | 2,846 | 928 | 1,246 | 2,195 | 2,254 | 606 | 1,319 | 10,230 | 4,911 | 31,136 |
| | Baseline | 2,920 | 1,826 | 2,876 | 1,179 | 1,296 | 2,264 | 2,346 | 627 | 1,343 | 10,860 | 5,034 | 32,571 |
| | High Demand | 3,567 | 2,137 | 3,256 | 1,297 | 1,316 | 2,305 | 2,372 | 631 | 1,352 | 11,330 | 5,058 | 34,621 |
| 2030 | Low Demand | 2,768 | 1,804 | 2,966 | 927 | 1,238 | 2,186 | 2,250 | 603 | 1,320 | 10,150 | 4,898 | 31,110 |
| | Baseline | 2,917 | 1,821 | 3,062 | 1,180 | 1,307 | 2,267 | 2,347 | 627 | 1,351 | 10,880 | 5,086 | 32,845 |
| | High Demand | 3,596 | 2,140 | 3,469 | 1,298 | 1,332 | 2,329 | 2,387 | 632 | 1,360 | 11,510 | 5,122 | 35,175 |

**Figure 24: Winter Coincident Peak Demand Forecasts**

| Winter Coincident Peak Demand Forecast (MW) | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Year | | A | B | C | D | E | F | G | H | I | J | K | NYCA |
| 2026-27 | Low Demand | 2,208 | 1,503 | 2,555 | 1,055 | 1,309 | 1,900 | 1,599 | 519 | 933 | 7,300 | 3,229 | 24,110 |
| | Baseline | 2,323 | 1,525 | 2,583 | 1,249 | 1,333 | 1,917 | 1,662 | 525 | 947 | 7,580 | 3,276 | 24,920 |
| | High Demand | 2,530 | 1,744 | 2,656 | 1,253 | 1,339 | 1,934 | 1,668 | 529 | 951 | 7,740 | 3,296 | 25,640 |
| 2027-28 | Low Demand | 2,202 | 1,499 | 2,655 | 1,094 | 1,300 | 1,900 | 1,612 | 519 | 937 | 7,250 | 3,262 | 24,230 |
| | Baseline | 2,329 | 1,531 | 2,688 | 1,316 | 1,343 | 1,939 | 1,701 | 528 | 956 | 7,650 | 3,335 | 25,316 |
| | High Demand | 2,668 | 1,827 | 2,898 | 1,469 | 1,347 | 1,965 | 1,719 | 530 | 963 | 7,880 | 3,350 | 26,616 |
| 2028-29 | Low Demand | 2,201 | 1,496 | 2,763 | 1,095 | 1,298 | 1,875 | 1,631 | 519 | 941 | 7,220 | 3,291 | 24,330 |
| | Baseline | 2,346 | 1,537 | 2,812 | 1,321 | 1,351 | 1,961 | 1,738 | 533 | 973 | 7,800 | 3,443 | 25,815 |
| | High Demand | 2,962 | 1,843 | 3,182 | 1,477 | 1,363 | 1,997 | 1,787 | 538 | 994 | 8,110 | 3,472 | 27,725 |
| 2029-30 | Low Demand | 2,200 | 1,494 | 2,911 | 1,094 | 1,296 | 1,884 | 1,638 | 515 | 944 | 7,180 | 3,352 | 24,508 |
| | Baseline | 2,361 | 1,540 | 2,966 | 1,322 | 1,374 | 1,988 | 1,771 | 539 | 989 | 7,930 | 3,585 | 26,365 |
| | High Demand | 3,085 | 1,864 | 3,406 | 1,479 | 1,409 | 2,069 | 1,811 | 550 | 1,009 | 8,320 | 3,673 | 28,675 |
| 2030-31 | Low Demand | 2,205 | 1,497 | 3,123 | 1,092 | 1,295 | 1,894 | 1,656 | 517 | 946 | 7,120 | 3,401 | 24,746 |
| | Baseline | 2,386 | 1,556 | 3,189 | 1,324 | 1,398 | 2,020 | 1,814 | 546 | 1,007 | 8,070 | 3,716 | 27,026 |
| | High Demand | 3,156 | 1,913 | 3,679 | 1,485 | 1,469 | 2,158 | 1,886 | 568 | 1,041 | 8,560 | 3,871 | 29,786 |

## Figure 25: Annual Energy Forecasts

| Annual Energy Forecast (GWh) | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Year | | A | B | C | D | E | F | G | H | I | J | K | NYCA |
| 2026 | Low Demand | 15,430 | 9,150 | 14,710 | 6,890 | 7,010 | 10,980 | 9,260 | 2,770 | 5,810 | 48,160 | 19,890 | 150,060 |
| | Baseline | 16,170 | 9,280 | 14,790 | 8,310 | 7,190 | 11,240 | 9,640 | 2,790 | 5,910 | 50,100 | 20,040 | 155,460 |
| | High Demand | 17,240 | 10,040 | 15,260 | 8,350 | 7,240 | 11,350 | 9,790 | 2,820 | 5,940 | 51,010 | 20,270 | 159,310 |
| 2027 | Low Demand | 15,330 | 8,970 | 15,040 | 7,640 | 6,850 | 10,910 | 9,300 | 2,770 | 5,830 | 47,170 | 19,700 | 149,510 |
| | Baseline | 16,160 | 9,150 | 15,200 | 9,280 | 7,130 | 11,410 | 9,830 | 2,800 | 5,950 | 50,260 | 20,040 | 157,210 |
| | High Demand | 18,350 | 10,970 | 16,550 | 10,080 | 7,150 | 11,420 | 10,000 | 2,840 | 5,990 | 51,790 | 20,390 | 165,530 |
| 2028 | Low Demand | 15,240 | 8,850 | 15,640 | 7,630 | 6,780 | 10,820 | 9,370 | 2,770 | 5,870 | 46,830 | 19,630 | 149,430 |
| | Baseline | 16,150 | 9,080 | 15,860 | 9,300 | 7,150 | 11,380 | 10,000 | 2,810 | 6,030 | 50,530 | 20,330 | 158,620 |
| | High Demand | 19,780 | 11,300 | 18,110 | 10,490 | 7,210 | 11,520 | 10,210 | 2,870 | 6,080 | 52,520 | 20,770 | 170,860 |
| 2029 | Low Demand | 15,110 | 8,730 | 16,450 | 7,590 | 6,700 | 10,720 | 9,330 | 2,770 | 5,890 | 46,270 | 19,680 | 149,240 |
| | Baseline | 16,120 | 9,000 | 16,750 | 9,270 | 7,160 | 11,360 | 10,060 | 2,820 | 6,080 | 50,730 | 20,800 | 160,150 |
| | High Demand | 21,220 | 11,330 | 20,020 | 10,520 | 7,420 | 11,710 | 10,320 | 2,890 | 6,160 | 53,250 | 21,350 | 176,190 |
| 2030 | Low Demand | 15,050 | 8,650 | 17,750 | 7,560 | 6,660 | 10,690 | 9,340 | 2,770 | 5,930 | 46,140 | 19,920 | 150,460 |
| | Baseline | 16,150 | 8,980 | 18,140 | 9,260 | 7,250 | 11,410 | 10,150 | 2,840 | 6,150 | 51,110 | 21,420 | 162,860 |
| | High Demand | 21,910 | 11,490 | 22,060 | 10,580 | 7,740 | 12,040 | 10,590 | 2,930 | 6,260 | 54,120 | 22,130 | 181,850 |

## Figure 26: Summer Non-Coincident Peak Demand Forecast

| Baseline Summer Non-Coincident Peak Demand Forecast (MW) | | | | | |
|---|---|---|---|---|---|
| Zone | 2026 | 2027 | 2028 | 2029 | 2030 |
| G-J | 15,280 | 15,349 | 15,392 | 15,423 | 15,452 |
| J | 11,030 | 11,060 | 11,080 | 11,100 | 11,120 |
| K | 5,072 | 5,089 | 5,088 | 5,112 | 5,165 |

## Figure 27: Winter Non-Coincident Peak Demand Forecast

| Baseline Winter Non-Coincident Peak Demand Forecast (MW) | | | | | |
|---|---|---|---|---|---|
| Zone | 2026-27 | 2027-28 | 2028-29 | 2029-30 | 2030-31 |
| G-J | 10,748 | 10,870 | 11,080 | 11,266 | 11,474 |
| J | 7,630 | 7,700 | 7,850 | 7,990 | 8,130 |
| K | 3,289 | 3,348 | 3,457 | 3,600 | 3,731 |

**Figure 28: Large Load Demand Forecast**

Large Loads Summer Peak Forecasts (MW)

| Zone | A | B | C | D | E | F | G | K | NYCA Total | Flexible Total |
|---|---|---|---|---|---|---|---|---|---|---|
| 2025 | 250 | 5 | 0 | 166 | 13 | 0 | 32 | 0 | 466 | 416 |
| 2026 | 335 | 11 | 72 | 518 | 15 | 0 | 72 | 0 | 1,023 | 685 |
| 2027 | 335 | 11 | 168 | 647 | 30 | 40 | 93 | 0 | 1,324 | 685 |
| 2028 | 335 | 11 | 288 | 647 | 41 | 40 | 104 | 7 | 1,473 | 685 |
| 2029 | 335 | 11 | 442 | 651 | 54 | 40 | 107 | 29 | 1,669 | 685 |
| 2030 | 335 | 11 | 653 | 651 | 70 | 40 | 110 | 70 | 1,940 | 685 |

Large Loads Winter Peak Forecasts (MW)

| Zone | A | B | C | D | E | F | G | K | NYCA Total | Flexible Total |
|---|---|---|---|---|---|---|---|---|---|---|
| 025-26 | 250 | 5 | 0 | 177 | 14 | 0 | 32 | 0 | 478 | 416 |
| 026-27 | 335 | 11 | 72 | 582 | 23 | 0 | 72 | 0 | 1,095 | 685 |
| 027-28 | 335 | 11 | 168 | 647 | 36 | 40 | 93 | 3 | 1,333 | 685 |
| 028-29 | 335 | 11 | 288 | 651 | 48 | 40 | 104 | 55 | 1,532 | 685 |
| 029-30 | 335 | 11 | 442 | 651 | 62 | 40 | 107 | 129 | 1,777 | 685 |
| 030-31 | 335 | 11 | 653 | 651 | 70 | 40 | 110 | 182 | 2,052 | 685 |

Note: These projections are included in the baseline zonal forecasts, and should not be added as additional load.

## Transmission Assumptions

The study assumptions for existing transmission facilities that are modeled as out-of-service are listed in Figure 29. Figure 30 shows the Con Edison series reactor status utilized in this STAR. There is one change in Con Edison series reactor assumptions in this STAR compared to the 2024 RNA. Figure 31 and Figure 32 provide a summary of the transmission projects included in the 2024 RNA as listed in the 2025 Gold Book.

**Figure 29: Existing Transmission Facilities Modeled Out-of-Service**

| From | To | kV | ID | Out-of-Service Through | |
|---|---|---|---|---|---|
| | | | | Prior STAR | Current STAR |
| Marion | Farragut | 345 | B3402 | Long-Term | |
| Marion | Farragut | 345 | C3403 | Long-Term | |
| Plattsburgh (1) | Plattsburgh | 230/115 | AT1 | 9/2026 | |
| Stolle Rd | Stolle Rd | 115 | T11-52 | 12/2025 | In-service |
| Station 23 | Station 42 | 115 | 920 | 12/2025 | In-service |
| E13th Street | | 345/69 | BK17 | - | 6/2027 |

Notes

(1) A spare transformer is placed in-service during the outage

**Figure 30: Con Edison Proposed Series Reactor Status**

| Terminals | | ID | kV | Summer | Winter |
|---|---|---|---|---|---|
| Dunwoodie | Mott Haven | 71 | 345 | In-Service | By-Passed |
| Dunwoodie | Mott Haven | 72 | 345 | In-Service | By-Passed |
| Sprainbrook | W. 49th Street | M51 | 345 | In-Service | By-Passed |
| Sprainbrook | W. 49th Street | M52 | 345 | In-Service | By-Passed |
| Farragut | Gowanus | 41 | 345 | By-Passed | In-Service |
| Farragut | Gowanus | 42 | 345 | By-Passed | In-Service |
| Sprainbrook | Uninondale Hub | Y49 | 345 | By-Passed | By-Passed |

**Figure 31: Major Transmission Projects Included in 2024 RNA**

| Queue | Project Name | MW | POI | Zone | Proposed Date |
|---|---|---|---|---|---|
| 631/887 | TDI Champlain Hudson Power Express (CHPE) | 1250 | Astoria Annex 345kV | J | May-26 |
| 1125 | Northern New York Priority Transmission Project (NNYPTP) | N/A | Moses/Adirondack/Porter path | D&E | Dec-25 |
| 1289/1667 | Propel NY Energy - Alternate Sol 5 | N/A | Sprain Brook, Tremont, East Garden City, Shore Road, additional Long Island Substations | I,J,K | May-30 |
| - | Brooklyn Clean Energy Hub | N/A | Between Farragut 345 kV and Rainey 345 kV | J | Jun-28 |
| - | Gowanus/Greenwood PAR Regulated Feeder | N/A | Gowanus 345 kV/Greenwood 138 kV TLA | J | May-25 |
| - | Goethals/Foxhills PAR Regulated Feeder | N/A | Goethals 345 kV/Greenwood 138 kV TLA | J | May-25 |
| - | Eastern Queens Clean Energy Hub | N/A | Between Jamaica 138 kV and Valley Stream/Lake Success 138 kV | J | Jun-28 |
| - | Gowanus/Greenwood PAR Regulated Feeder | N/A | Gowanus 345 kV/Greenwood 138 kV TLA | J | May-26 |

**Figure 32: Transmission Project Inclusion Rules Application for 2024 RNA**

| Transmission Project Inclusion Rules Application: Class Year Transmission, TIP, and Firm LTP Projects Not Included in the 2025 RPP Base Cases | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Transmission Owner | Terminals | | Line Length (Miles) | Proposed In-Service Date | | Nominal Voltage (kV) | | # of CKTs | Thermal Ratings | | Project Description / Conductor Size |
| | | | | Prior to | Year | Operating | Design | | Summer | Winter | |
| NYSEG | New Gardenville | New Gardenville | xfmr | W | 2030 | 115/34.5 | 115/34.5 | 1 | 50 | 60 | NYSEG Transformer #7 and Station Reconfiguration |
| NYSEG | New Gardenville | New Gardenville | xfmr | W | 2030 | 115/34.5 | 115/34.5 | 2 | 50 | 60 | NYSEG Transformer #8 and Station Reconfiguration |
| NYSEG | New Gardenville | New Gardenville | xfmr | W | 2030 | 230/115 | 230/115 | 1 | 316 MVA | 370 MVA | NYSEG Transformer #6 and Station Reconfiguration |
| Clean Path New York LLC | Fraser 345kV | Rainey 345kV | HVDC | S | 2028 | 492 | 492 | 1 | 1300 MW | 1300 MW | -/+ 400kV Bipolar HVDC cable |

# Appendix D: Resource Adequacy Assumptions

## 2025 Q4 STAR MARS Assumptions Matrix

| | Parameter | 2024 RNA Base Cases<br><br>Key Assumptions<br><br>(2024 Gold Book) | 2025 RPP,<br>2025 Q3, Q4 STAR<br><br>Key Assumptions<br><br>(2025 GB) |
|---|---|---|---|
| 0 | Relevant Links | • 2024 RNA Report Appendices<br>• 2025-2034 CRP Report Appendices | • July 23 ESPWG 2025 Q3 STAR Assumptions<br>• Nov. 10, 2025 Q3 STAR Solutions Solicitation<br>• Nov 7 ESPWG 2025 Q4 STAR Assumptions |
| Load Parameters | | | |
| 1 | **Peak** Load Forecast | Adjusted 2024 Gold Book NYCA baseline peak load forecast. It includes large loads from the NYISO interconnection queue, with forecasted impacts. Baseline load represents coincident summer peak demand and includes the reductions due to projected energy efficiency programs, building codes and standards, BtM storage impacts at peak, distributed energy resources and BtM solar photovoltaic resources; it also reflects expected impacts (increases) from projected electric vehicle usage and electrification.<br>The 2024 GB baseline peak load forecast includes the impact (reduction) of behind-the-meter (BtM) solar at the time of NYCA peak. For the BtM Solar adjustment, gross load forecasts that include the impact of the BtM generation are used for the 2024 RNA, which then allows for a discrete modeling of the BtM solar resources using 5 years of inverter data. | Adjusted 2025 Gold Book NYCA baseline peak load forecast. It includes large loads from the NYISO interconnection queue, with forecasted impacts. Baseline load represents coincident summer peak demand and includes the reductions due to projected energy efficiency programs, building codes and standards, BtM storage impacts at peak, distributed energy resources and BtM solar photovoltaic resources; it also reflects expected impacts (increases) from projected electric vehicle usage and electrification.<br>The 2025 GB baseline peak load forecast includes the impact (reduction) of behind-the-meter (BtM) solar at the time of NYCA peak. For the BtM Solar adjustment, gross load forecasts that include the impact of the BtM generation are used for the 2025 RPP, which then allows for a discrete modeling of the BtM solar resources using 5 years of inverter data. |
| 1a | Proposed large loads | As included in the Baseline Peak Load Forecast from the Gold Book. Certain large loads that are assumed flexible (e.g., crypto, hydrogen) are modeled as EOP step. | As included in the Baseline Peak Load Forecast from the Gold Book. Certain large loads that are assumed flexible (e.g., crypto, hydrogen) are modeled as EOP step. |
| 2 | Load **Shapes**<br><br>(Multiple Load Shapes) | Used Multiple Load Shape MARS Feature *(see March 24, 2022 LFTF/ESPWG).*<br>8,760-hour historical gross load shapes were used as base shapes for LFU bins:<br>Load Bins 1 and 2: 2013<br>Load Bins 3 and 4: 2018<br>Load Bins 5 to 7: 2017<br>Historical load shapes are adjusted to meet zonal (as well as G-J) coincident and non-coincident peak forecasts (summer and winter), while maintaining the energy targets.<br><br>For the BtM Solar discrete modeling, gross load forecasts that include the impact of the BtM generation are used (additional details under the BtM Solar category below). | Used Multiple Load Shape MARS Feature *(see March 24, 2022 LFTF/ESPWG).*<br>8,760-hour historical gross load shapes were used as base shapes for LFU bins:<br>Load Bins 1 and 2: 2013<br>Load Bins 3 and 4: 2018<br>Load Bins 5 to 7: 2017<br>Historical load shapes are adjusted to meet zonal (as well as G-J) coincident and non-coincident peak forecasts (summer and winter), while maintaining the energy targets.<br><br>For the BtM Solar discrete modeling, gross load forecasts that include the impact of the BtM generation are used (additional details under the BtM Solar category below). |
| 3 | Load Forecast Uncertainty (LFU)<br><br>The LFU model captures the impacts of weather conditions on future loads. | Same summer LFU values as the ones presented in 2023 *(as presented at the May 26, 2023 LFTF [link] and also presented at the April 18, 2024 LFTF [link])*<br><br>**New Additional Method for Winter:**<br>**Winter Dynamic Load Forecast Uncertainty (LFU)**: In order to reflect uncertainty stemming from | Same summer LFU values as the ones presented in 2023 *(as presented at the May 26, 2023 LFTF [link] and also presented at the April 18, 2024 LFTF [link])*<br><br>**Starting 2024 RNA, winter Dynamic Load Forecast Uncertainty (LFU)**: In order to reflect uncertainty stemming from electrification, electric vehicles |

| | | | |
|---|---|---|---|
| | | electrification, electric vehicles (EVs), and large loads, the 2024 RNA will use a winter LFU multipliers model. Over the study period year 2 through year 10, dynamic winter LFU multipliers were calculated, reflecting the increasing share and load behavior of EV charging load, heating electrification, and large load projects. The dynamic winter LFU multipliers increase over the study horizon, reflecting the increasing winter weather sensitivity due to additional EV charging and electric heating load. Note: the first winter of the study period (winter 2024-25) match those calculated using recent winter load and weather data.<br>Additional details are available in the April 18 TPAS/ESPWG/LFTF presentation [link] | (EVs), and large loads, starting with the 2024 RNA used a winter LFU multipliers model. Over the study period year 2 through year 10, dynamic winter LFU multipliers were calculated, reflecting the increasing share and load behavior of EV charging load, heating electrification, and large load projects. The dynamic winter LFU multipliers increase over the study horizon, reflecting the increasing winter weather sensitivity due to additional EV charging and electric heating load. Note: the first winter of the study period (winter 2024-25) match those calculated using recent winter load and weather data.<br>Additional details are available in the May 29 TPAS/ESPWG/LFTF presentation [link] |
| **Generation Parameters** | | | |
| 1 | **Existing** Generating Unit Capacities (*e.g., thermal units, large hydro)* | 2024 Gold Book values:<br>Summer is min of (DMNC, CRIS).<br>Winter is min of (DMNC, CRIS).<br>Adjusted for RNA Base Case inclusion rules application | 2025 Gold Book values:<br>Summer is min of (DMNC, CRIS).<br>Winter is min of (DMNC, CRIS).<br>Adjusted for RNA Base Case inclusion rules application |
| 2 | **Proposed New Units Inclusion** Determination | 2024 Gold Book with RNA Base Case inclusion rules applied | 2025 Gold Book with RNA Base Case inclusion rules applied |
| 3 | Retirement, Mothballed Units, IIFO | 2024 Gold Book with RNA Base Case inclusion rules applied | 2025 Gold Book with RNA Base Case inclusion rules applied |
| 4 | Forced and Partial Outage Rates (*e.g., thermal units)* | Five-year (2019-2023) GADS data for each unit represented.<br>Transition Rates representing the Equivalent Forced Outage Rates (EFORd) during demand periods over the most recent five-year period.<br><br>For new units or units that are in service for less than three years, NERC 5-year class average EFORd data are used. | Five-year (2020-2024) GADS data for each unit represented.<br>Transition Rates representing the Equivalent Forced Outage Rates (EFORd) during demand periods over the most recent five-year period.<br><br>For new units or units that are in service for less than three years, NERC 5-year class average EFORd data are used. |
| 5 | Modeling of Non-firm Gas Unavailability During Winter Peak Conditions | **New:**<br>In order to simulate anticipated risks from cold snaps on the gas availability, gas plants available MWs in NYCA are further derated, *i.e.,* all gas-only units with non-firm gas within the NYCA are assumed unavailable**.** Also, certain dual-fuel units with duct-burn capability are derated. The forecasted winter coincident peak is used to determine when the gas derates are applied in the RNA Base Cases and for each load bin and Study Year. | **Starting 2024 RNA:**<br>In order to simulate anticipated risks from cold snaps on the gas availability, gas plants available MWs in NYCA are further derated, *i.e.,* all gas-only units with non-firm gas within the NYCA are assumed unavailable**.** Also, certain dual-fuel units with duct-burn capability are derated. The forecasted winter coincident peak is used to determine when the gas derates are applied in the RNA Base Cases and for each load bin and Study Year. |
| 6 | Daily Maintenance | Fixed maintenance based on schedules received by the NYISO. | Fixed maintenance based on schedules received by the NYISO. |
| 7 | Weekly Planned Maintenance | MARS is automatically scheduling maintenance based on NYCA capacity and demand.<br><br>Data: 5y (2019-2023) of historical scheduled maintenance data from Operations and GADS system to determine the number of weeks on maintenance for each thermal unit. | MARS is automatically scheduling maintenance based on NYCA capacity and demand.<br><br>Data: 5y (2020-2024) of historical scheduled maintenance data from Operations and GADS system to determine the number of weeks on maintenance for each thermal unit. |

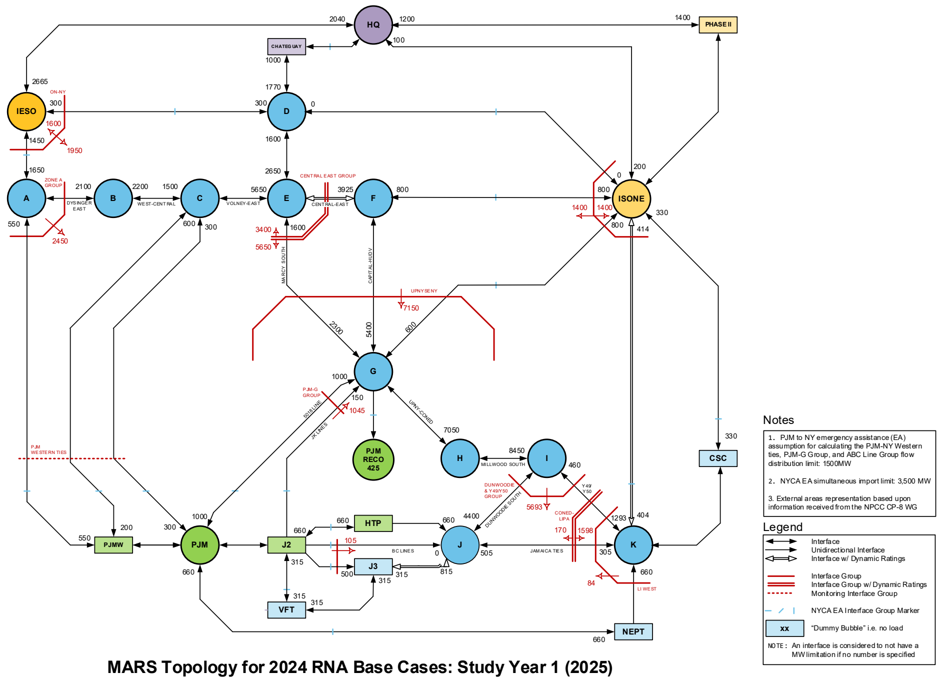
| | | | |
|---|---|---|---|
| 8 | Summer Maintenance | None | None |
| 9 | Combustion Turbine Derates | Derate based on temperature correction curves.<br><br>Thermal derates are based on a ratio of peak load before LFU is applied and LFU applied load.<br><br>For new units: used data for a unit of same type in same zone, or neighboring zone data. | Derate based on temperature correction curves.<br><br>Thermal derates are based on a ratio of peak load before LFU is applied and LFU applied load.<br><br>For new units: used data for a unit of same type in same zone, or neighboring zone data. |
| 10 | Existing Landfill Gas (LFG) Plants | Actual hourly plant output over the last 5 years. Program randomly selects an LFG shape of hourly production over the last 5 years for each model replication.<br><br>Probabilistic model is incorporated based on five years of input shapes, with one shape per replication randomly selected in the Monte Carlo process. | Actual hourly plant output over the last 5 years. Program randomly selects an LFG shape of hourly production over the last 5 years for each model replication.<br><br>Probabilistic model is incorporated based on five years of input shapes, with one shape per replication randomly selected in the Monte Carlo process. |
| 11 | Existing and Proposed **Wind** Units | **New data source:**<br>Model-based hourly data over the available past 5 years (2017-2021 developed by DNV-GL). For any unit that was included in the DNV data the data "as is" was used. For any unit not included a weighted zonal average was modeled.<br><br>Probabilistic model is incorporated based on five years of input shapes with one shape per replication being randomly selected in Monte Carlo process. | **Starting 2024 RNA, new data source:**<br>Model-based hourly data over the available past 5 years (2020-2024 developed by DNV-GL). For any unit that was included in the DNV data the data "as is" was used. For any unit not included a weighted zonal average was modeled.<br><br>Probabilistic model is incorporated based on five years of input shapes with one shape per replication being randomly selected in Monte Carlo process. |
| 12 | Proposed **Offshore Wind** Units | RNA Base Case inclusion rules Applied to determine the generator status.<br><br>**New data source:**<br>5 years of hourly model-based data as developed by DNV-GL (2017-2021) | RNA Base Case inclusion rules Applied to determine the generator status.<br><br>5 years of hourly model-based data as developed by DNV-GL (2020-2024) |
| 13 | Existing and Proposed **Utility-scale Solar Resources** | **New data source:**<br>Probabilistic model chooses from the model-based data shapes covering past available 5 years (2017-2021), as developed by DNV-GL.<br><br>One shape per replication is randomly selected in Monte Carlo process. | Probabilistic model chooses from the model-based data shapes covering past available 5 years (2020-2024), as developed by DNV-GL.<br><br>One shape per replication is randomly selected in Monte Carlo process. |
| 14 | **BtM Solar Resources** | **Supply side:**<br>Past five years (2017-2021) of 8,760 hourly MW profiles based on sampled inverter data.<br>The MARS random shape mechanism randomly picks one 8,760 hourly shape (of five) for each replication year; similar with the past planning modeling and aligns with the method used for wind, utility solar, landfill gas, and run-of-river facilities.<br>**Load side:**<br>Gross load forecasts | **Supply side:**<br>Past five years (2020-2024) of 8,760 hourly MW profiles based on sampled inverter data.<br>The MARS random shape mechanism randomly picks one 8,760 hourly shape (of five) for each replication year; similar with the past planning modeling and aligns with the method used for wind, utility solar, landfill gas, and run-of-river facilities.<br>**Load side:**<br>Gross load forecasts |
| 15 | Existing **BTM-NG Program** | These units are former load modifiers that sell capacity into the ICAP market.<br><br>Modeled as cogen type 1 (or type 2 as applicable) unit in MARS. Unit capacity set to CRIS value, load modeled with weekly pattern that can change monthly. | These units are former load modifiers that sell capacity into the ICAP market.<br><br>Modeled as cogen type 1 (or type 2 as applicable) unit in MARS. Unit capacity set to CRIS value, load modeled with weekly pattern that can change monthly. |
| 16 | Existing **Small Hydro** Resources (*e.g.*, run of river) | Actual hourly plant output over the past 5 years period. Program randomly selects a hydro shape of hourly production over the 5-year window for each model replication. The randomly selected shape is multiplied by their current nameplate rating. | Actual hourly plant output over the past 5 years period. Program randomly selects a hydro shape of hourly production over the 5-year window for each model replication. The randomly selected shape is multiplied by their current nameplate rating. |

| | | | |
|---|---|---|---|
| 17 | Existing **Large Hydro** | Probabilistic Model based on 5 years of GADS data.<br><br>Transition Rates representing the Equivalent Forced Outage Rates (EFORd) during demand periods over the most recent five-year period. Methodology consistent with thermal unit transition rates. | Probabilistic Model based on 5 years of GADS data.<br><br>Transition Rates representing the Equivalent Forced Outage Rates (EFORd) during demand periods over the most recent five-year period. Methodology consistent with thermal unit transition rates. |
| 18 | Proposed front-of-meter **Battery Storage** | GE MARS 'ES' model is used. Units are given a maximum capacity, maximum stored energy, and a dispatch window. | GE MARS 'ES' model is used. Units are given a maximum capacity, maximum stored energy, and a dispatch window. |
| 19 | Existing Energy Limited Resources (**ELRs**) | GE developed MARS functionality to be used for ELRs.<br><br>Resource output is aligned with the NYISO's peak load window when most loss-of-load events are expected to occur. | GE developed MARS functionality to be used for ELRs.<br><br>Resource output is aligned with the NYISO's peak load window when most loss-of-load events are expected to occur. |
| **Transaction – Imports/ Exports** | | | |
| 1 | Capacity Purchases | Grandfathered Rights and other awarded long-term rights<br><br>Modeled using MARS explicit contracts feature. | Grandfathered Rights and other awarded long-term rights<br><br>Modeled using MARS explicit contracts feature. |
| 2 | Capacity Sales | These are long-term contracts filed with FERC.<br><br>Modeled using MARS explicit contracts feature. Contracts sold from ROS (Zones: A-F). ROS ties to external pool are derated by sales MW amount | These are long-term contracts filed with FERC.<br><br>Modeled using MARS explicit contracts feature. Contracts sold from ROS (Zones: A-F). ROS ties to external pool are derated by sales MW amount |
| 3 | FCM Sales | Model sales for known years<br><br>Modeled using MARS explicit contracts feature. Contracts sold from ROS (Zones: A-F). ROS ties to external pool are derated by sales MW amount | Model sales for known years<br><br>Modeled using MARS explicit contracts feature. Contracts sold from ROS (Zones: A-F). ROS ties to external pool are derated by sales MW amount |
| 4 | UDRs | Updated with most recent elections/awards information (VFT, HTP, Neptune, CSC)<br><br>Added CHPE HVDC (from Hydro Quebec into Zone J) at 1250 MW (summer only) starting 2026. | Updated with most recent elections/awards information (VFT, HTP, Neptune, CSC)<br><br>Added CHPE HVDC (from Hydro Quebec into Zone J) at 1250 MW (summer only) starting 2026. |
| 5 | External Deliverability Rights (EDRs) | Cedars Uprate 80 MW. Modeled reflecting External CRIS rights. | Cedars Uprate 80 MW. Modeled reflecting External CRIS rights. |
| 6 | Wheel-Through Contract | 300 MW HQ through NYISO to ISO-NE.<br>Modeled as firm contract; reduced the transfer limit from HQ to NYISO by 300 MW and increased the transfer limit from NYISO to ISO-NE by 300 MW. | 300 MW HQ through NYISO to ISO-NE.<br>Modeled as firm contract; reduced the transfer limit from HQ to NYISO by 300 MW and increased the transfer limit from NYISO to ISO-NE by 300 MW. |
| **MARS Topology:** a simplified bubble-and-pipe representation of the transmission system | | | |
| 1 | Interface Limits | Developed by review of previous studies and specific analysis prior and during the RNA study process. | Developed by review of previous studies and specific analysis prior and during the RNA study process. **Starting with the 2025 models, Chateaugay to NY limit set to zero for winter.** |
| 2 | New Transmission | Based on TO-provided firm plans via Gold Book/LTP 2024 processes) and proposed merchant transmission and public policy facilities meeting the RNA Base Case inclusion rules. | Based on TO-provided firm plans (via Gold Book/LTP 2025 processes) and proposed merchant transmission and public policy facilities meeting the Base Case inclusion rules. |

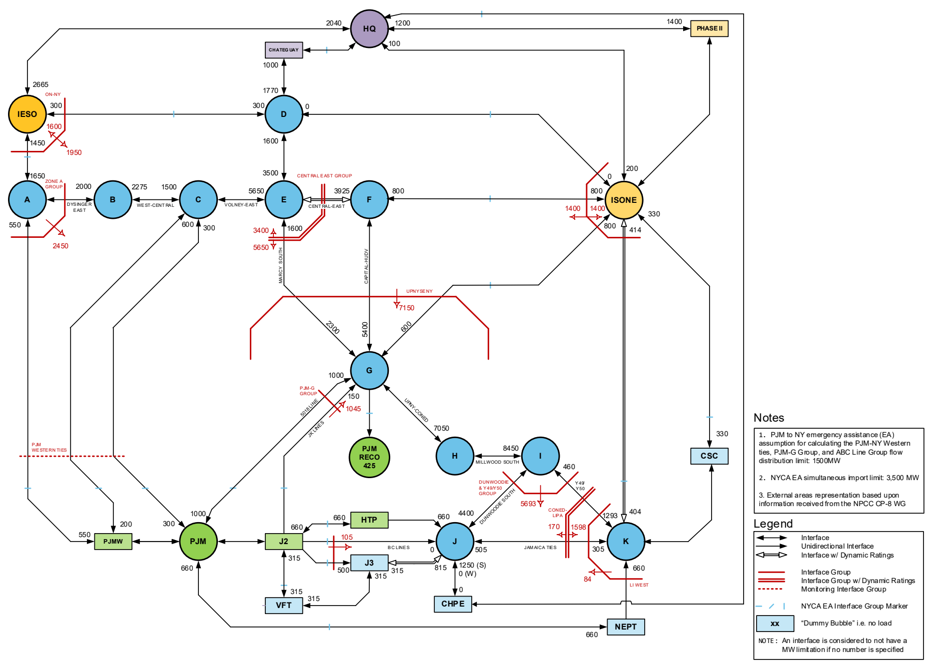
| | | | |
|---|---|---|---|
| 3 | AC Cable Forced Outage Rates | All existing cable transition rates updated with data received from ConEd and PSEG-LIPA to reflect most recent five-year history. | All existing cable transition rates updated with data received from ConEd and PSEG-LIPA to reflect most recent ten-year history. |
| 4 | UDR unavailability | Five-year history of forced outages. | Ten-year history of forced outages. |
| **Emergency Operating Procedures (EOPs)** | | | |
| 1 | EOP Steps Order | **New order, and new flexible large loads at step 2:**<br>1. No EOP Support<br>2. Flexible Large Loads (400-900 MW)<br>3. Special Case Resources (SCRs) (Load and Generator)<br>4. 5% Manual Voltage Reduction<br>5. 30-Minute Operating Reserve to Zero (655 MW)<br>6. Voluntary Load Curtailment<br>7. Public Appeals<br>8. 5% Remote Controlled Voltage Reduction<br>9. Emergency Assistance from External Areas<br>10. Part of the 10-Minute Operating Reserve (910 MW of 1310 MW) to Zero | **Starting 2024 RNA, new EOP order and flexible large loads:**<br>1. No EOP Support<br>2. Flexible Large Loads (about 485 MW at max)<br>3. Special Case Resources (SCRs) (Load and Generator)<br>4. 5% Manual Voltage Reduction<br>5. 30-Minute Operating Reserve to Zero (655MW)<br>6. Voluntary Load Curtailment<br>7. Public Appeals<br>8. 5% Remote Controlled Voltage Reduction<br>9. Emergency Assistance from External Areas<br>10. Part of the 10-Minute Operating Reserve (910 MW of 1310 MW) to Zero |
| 2 | Special Case Resources (SCR) | SCRs sold for the program discounted to historic availability (“effective capacity”). Monthly variation based on historical experience.<br><br>Summer values calculated from the latest available July registrations (July 2023 SCR enrollment) held constant for all years of study.<br><br>**New Method:**<br><br>SCRs are modeled as duration-limited resources. The duration limited units are constrained to be called once in a day when a loss of load event occurs, and are invoked between 5 and 7 hours (defined by zone), which is determined based on historical SCR performance in the applicable zone. Hourly response rates are used. The contribution by the SCRs vary monthly by applicable zone. These monthly values are also derived from historical performance of the SCRs. Additional details in the January 3, 2024 ICS/ICAP presentation [link] and May 1, 2024 ICS [link]. | SCRs sold for the program discounted to historic availability (“effective capacity”). Monthly variation based on historical experience.<br><br>Summer values calculated from the latest available July registrations (July 2024 SCR enrollment) held constant for all years of study.<br><br>**Starting 2024 RNA, new method:**<br><br>SCRs are modeled as duration-limited resources. The duration limited units are constrained to be called once in a day when a loss of load event occurs, and are invoked between 5 and 7 hours (defined by zone), which is determined based on historical SCR performance in the applicable zone. Hourly response rates are used. The contribution by the SCRs vary monthly by applicable zone. These monthly values are also derived from historical performance of the SCRs. Additional details in the January 3, 2024 ICS/ICAP presentation [link] and May 1, 2024 ICS [link]. |
| 3 | EDRP Resources | Not modeled if the values are less than 2 MW. | Not modeled if the values are less than 2 MW. |
| 4 | Operating Reserves | 655 MW 30-min reserve to zero<br>910 MW (of 1310 MW) 10-min reserve to zero<br><br>Note: the 10-min reserve modeling method is updated per NYISO’s recommendation (approved at the Oct. 3, 2023 NYSRC ICS [link]) to maintain (or no longer deplete/use) 400 MW of the 1,310 MW 10-min operating reserve at the applicable EOP step. Therefore, the 10-min operating reserve MARS EOP step will use, as needed each MARS replication: 910 MW (=1,310 MW–400 MW). | 655 MW 30-min reserve to zero<br>910 MW (of 1310 MW) 10-min reserve to zero<br><br>Note: the 10-min reserve modeling method is updated per NYISO’s recommendation (approved at the Oct. 3, 2023 NYSRC ICS [link]) to maintain (or no longer deplete/use) 400 MW of the 1,310 MW 10-min operating reserve at the applicable EOP step. Therefore, the 10-min operating reserve MARS EOP step will use, as needed each MARS replication: 910 MW (=1,310 MW–400 MW). |
| 5 | Other EOPs<br><br>*(e.g., manual voltage reduction, voltage curtailments, public appeals, external assistance, as listed above)* | Based on TO information, measured data, and NYISO forecasts. Will use 2024 elections, as available. | Based on TO information, measured data, and NYISO forecasts. Will use 2024 elections, as available. |
| **External Control Areas Modeling Assumptions** | | | |

| | | | |
|---|---|---|---|
| • External models (NE, HQ, Ontario, PJM) received via the NPCC CP-8 WG process.<br>• Starting 2024 RNA, the top 5 (instead of 3) summer and winter peak load days of an external Control Area modeled as coincident with the NYCA top 5 peak load days.<br>• Load and capacity fixed through the study years.<br>• The renewable and energy limited shapes are removed.<br>• EOPs are not represented for the external Control Area capacity models.<br>• External Areas adjusted to be between 0.1 and 0.15 event-days/year LOLE by adjusting capacity pro-rata in all areas.<br>• Implemented a statewide emergency assistance (from the neighboring systems) limit of 3500 MW.<br>• LFU is applied to neighboring systems.<br>• Same load historical years are used as NY. | | | |
| 1 | PJM | Simplified model: The 5 PJM MARS areas (bubbles) were consolidated into one starting 2020 RNA. As per RNA procedure. | Simplified model: The 5 PJM MARS areas (bubbles) were consolidated into one starting 2020 RNA. As per RNA procedure. |
| 2 | ISONE | Simplified model: The 8 ISO-NE MARS areas (bubbles) were consolidated into one starting 2020 RNA | Simplified model: The 8 ISO-NE MARS areas (bubbles) were consolidated into one starting 2020 RNA |
| 3 | HQ | Per RNA Procedure. | Per RNA Procedure. |
| 4 | IESO | Per RNA procedure. | Per RNA procedure. |
| 5 | Reserve Sharing | All NPCC Control Areas indicate that they will share reserves equally among all members before sharing with PJM. | All NPCC Control Areas indicate that they will share reserves equally among all members before sharing with PJM. |
| 6 | NYCA Emergency Assistance Limit | Implemented a statewide limit of 3,500 MW, additional to the “pipe” limits. | Implemented a statewide limit of 3,500 MW, additional to the “pipe” limits. |
| Miscellaneous | | | |
| 1 | MARS Model Version | 4.14.2179 | 5.7.3765 |

## 2024 RNA MARS Topology[20]




**MARS Topology for 2024 RNA Base Cases: Study Year 1 (2025)**




**MARS Topology for 2024 RNA Base Cases: Study Years 2 through 5 (2026-2029) (with CHPE)**

[20] This is the MARS topology used for 2024 Reliability Needs Assessment studies and is not fully re-evaluated for each quarterly STAR.

# Appendix E: Transmission Security Margin Assessment

## Introduction

The purpose of this assessment is to identify plausible changes in conditions or assumptions that might adversely impact the reliability of the BPTF or "tip" the system into a violation of a transmission security criterion. This assessment is performed using a deterministic approach through a spreadsheet-based method using input from the 2025 Gold Book and the projects that meet the reliability planning inclusion rules for the 2025 Quarter 4 STAR. For this assessment, the statewide system margin is calculated and transmission security margins for the Lower Hudson Valley, New York City, and Long Island localities are calculated.

A BPTF reliability need is identified when the transmission security margin in the Lower Hudson Valley, New York City, or Long Island localities is less than zero. Additional details beyond the system design conditions regarding the statewide system margin, impact of extreme weather, or conditions are provided to more fully understand the impact of various changes to the system such as demand forecast or other parameters in the assessment.

For the evaluation of winter peak conditions, all gas-only units within the NYCA are assumed unavailable with consideration of firm gas fuel contracts. Dual-fuel units with gas-only duct-burn capability are assumed to be available at a lower capacity, accounting for the unavailability of duct-burn. This assessment assumes the remaining units have available fuel for the peak period. This shortage impacts approximately 6,325 MW of gas generation throughout the NYCA.

Transmission security analysis represents discrete snapshots in time of various credible combinations of system conditions. Therefore, the identification of reliability needs only indicates the magnitude of the need (*e.g.*, a thermal overload expressed in terms of percentage of the applicable rating) under those specific system conditions. Additional details are required to fully describe the nature of the need. To describe the nature of the transmission security and statewide system margins more fully, the NYISO uses load shapes to reflect the expected behavior of the load over 24 hours on the summer peak day for the 10-year study horizon. Details of the load shapes are provided in the body of this report in  and .

Further details on the assumptions utilized in this assessment are provided in Appendix C. Under expected weather conditions this assessment recognizes that there is a range of possibilities for the expected weather demand forecast driven by key assumptions, such as population and economic growth, energy efficiency, installation of behind-the-meter renewable energy resources, and electric vehicle adoption and charging patterns that are captured in the 2025 Gold Book. Extreme weather and other risk factors were further explored in the 2025–2034 CRP.

Key to the determination of generator deactivation reliability needs is the availability of future planned projects, such as CHPE, Empire Wind, Sunrise Wind, and the Propel NY project. These evaluations are labeled with "status quo." The status quo evaluation assumes that transmission and generation projects that are currently planned for but not currently in service (3,600 MW generation projects, as described above) do not enter service during the planning horizon, while maintaining the assumption that demand grows as forecasted, including large load development.

### Statewide System Margin

The statewide system margin for New York is evaluated under expected weather for summer and winter conditions with normal transfer criteria. The statewide system margin is the ability to meet the forecasted load and largest loss-of-source contingency (*i.e.,* total capacity requirement) against the NYCA generation (including derates) and external area interchanges. The NYCA generation (from line-item A in the following figures) is comprised of the existing generation plus additions of future generation resources, as well as the removal of deactivating generation, that meet the reliability planning process inclusion rules. The dispatch of renewable generation is aligned with current transmission planning practices for transmission security. Derates for thermal resources based on their NERC five-year class average EFORd are also included.[21] Additionally, for the statewide system margin, the NYCA generation includes the Oswego export limit with all lines in service.

The decreasing statewide system margin in both summer and winter can be attributed to increasing demand that is not matched by incoming proposed generation that meets inclusion rules. Additionally, the unavailability of non-firm gas is a key driver of deficient statewide margins in the winter peak condition. A negative statewide system margin is not, on its own, a violation of the Reliability Criteria. It is, however, a leading indicator of the system's inability to securely serve demand under normal operations. This metric is further explored in the 2025-2034 CRP.[22]

[21] The NERC five-year class average EFORd data is available here. NERC class average derating factors used in the STAR do not have a mechanism for excluding 9300 events (generator outages due to transmission system problems), see further discussion in Oct. 7, 2024 ICAP/MIWG/PRLWG presentation.
[22] The most recent draft of the NYISO's 2025-2034 Comprehensive Reliability Plan is found with the October, 16, 2025 Operating Committee Materials (here)

## Figure 33: Summer Peak Statewide System Margin Calculation - Planned System, Flexible Large Loads Offline

| Line | Item | Summer Peak - Expected Summer Weather, Normal Transfer Criteria (MW) | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 |
| A | NYCA Generation (1) | 37,705 | 40,483 | 41,787 | 41,787 | 41,787 | 41,333 | 41,333 | 41,333 | 41,333 |
| B | NYCA Generation Unavailability (2) | (6,700) | (9,133) | (10,302) | (10,328) | (10,353) | (10,332) | (10,357) | (10,357) | (10,383) |
| C | Temperature Based Generation Derates | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| D | External Area Interchanges (3) | 3,208 | 2,919 | 2,919 | 2,919 | 2,919 | 2,919 | 2,919 | 2,919 | 2,919 |
| E | **Total Resources (A+B+C+D)** | 34,212 | 34,269 | 34,405 | 34,379 | 34,353 | 33,920 | 33,894 | 33,894 | 33,869 |
| | | | | | | | | | | |
| F | Demand Forecast (5) | (31,305) | (31,590) | (31,698) | (31,886) | (32,160) | (32,434) | (32,757) | (33,101) | (33,399) |
| G | Largest Loss-of-Source Contingency | (1,310) | (1,310) | (1,310) | (1,310) | (1,310) | (1,310) | (1,310) | (1,310) | (1,310) |
| H | **Total Capability Requirement (F+G)** | (32,615) | (32,900) | (33,008) | (33,196) | (33,470) | (33,744) | (34,067) | (34,411) | (34,709) |
| | | | | | | | | | | |
| I | **Statewide System Margin (E+H)** | 1,597 | 1,369 | 1,397 | 1,183 | 883 | 176 | (173) | (517) | (840) |
| J | Higher Demand Impact | (600) | (1,170) | (1,650) | (2,050) | (2,330) | (2,520) | (2,660) | (2,830) | (3,160) |
| K | **Higher Demand Statewide System Margin (I+J)** | 997 | 199 | (253) | (867) | (1,447) | (2,344) | (2,833) | (3,347) | (4,000) |
| L | SCRs (6), (7) | 804 | 804 | 804 | 804 | 804 | 804 | 804 | 804 | 804 |
| M | **Statewide System Margin with SCR (K+L)** | 1,801 | 1,003 | 550 | (63) | (643) | (1,540) | (2,029) | (2,543) | (3,197) |
| N | Operating Reserve | (1,310) | (1,310) | (1,310) | (1,310) | (1,310) | (1,310) | (1,310) | (1,310) | (1,310) |
| O | **Statewide System Margin with Full Operating Reserve (M+N) (4)** | 491 | (307) | (760) | (1,373) | (1,953) | (2,850) | (3,339) | (3,853) | (4,507) |

Notes:

1. Reflects the 2025 Gold Book existing summer capacity plus projected additions and deactivations.
2. Reflects the derates for generating resources. For this evaluation land-based wind generation is assumed to have a capability of 5% of the total nameplate, off-shore wind at 15% of the total nameplate, solar generation is based on the ratio of solar PV nameplate capacity (2025 Gold Book Table I-9a) and solar PV peak reductions (2025 Gold Book Table I-9c). Derates for run-of-river hydro are included as well as the Oswego Export limit for all lines in-service. Includes derates for thermal resources based on NERC five-year class average EFORd data published October 2024 (https://www.nerc.com/pa/RAPA/gads/Pages/Reports.aspx). Also includes a reduction of 310 MW based on the impact of Correlated Derates to DMNC on resources impacted by the Modeling Improvements for "Capacity Accreditation project – Correlated Derates" requirements are reflected in the NYISO ICAP manual and the Market Services Tariff Section 5.
3. Interchanges are based on ERAG MMWG values and firm transactions. Includes a 175 MW reduction in capacity sales from PJM. Includes external imports from the Cross-Sound Cable in accordance with planned imports through early 2027, but starting in summer 2027 this import is assumed at 0 MW.
4. For informational purposes.
5. Reflects the 2025 Gold Book Forecast.
6. SCRs are not applied for transmission security analysis of normal operations, but are included for emergency operations.
7. Includes a derate of 401 MW for SCRs

### Figure 34: Winter Peak Statewide System Margin – Planned System, Flexible Large Loads Offline

| Line | Item | Winter Peak - Baseline Expected Winter Weather, Normal Transfer Criteria (MW) | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | | **2026-27** | **2027-28** | **2028-29** | **2029-30** | **2030-31** | **2031-32** | **2032-33** | **2033-34** | **2034-35** |
| A | NYCA Generation (1) | 42,115 | 43,484 | 43,864 | 43,864 | 43,407 | 43,407 | 43,407 | 43,407 | 43,407 |
| B | NYCA Generation Unavailability (2) | (8,575) | (9,759) | (10,139) | (10,139) | (10,139) | (10,139) | (10,139) | (10,139) | (10,139) |
| C | Unavailability of Non-Firm Gas (6) | (6,328) | (6,328) | (6,328) | (6,328) | (5,870) | (5,870) | (5,870) | (5,870) | (5,870) |
| D | Temperature Based Generation Derates | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| E | External Area Interchanges (3) | 849 | 560 | 560 | 560 | 560 | 560 | 560 | 560 | 560 |
| F | **Total Resources (A+B+C+D+E)** | 28,061 | 27,957 | 27,957 | 27,957 | 27,958 | 27,958 | 27,958 | 27,958 | 27,958 |
| | | | | | | | | | | |
| G | Demand Forecast (5) | (24,920) | (25,316) | (25,815) | (26,365) | (27,026) | (27,671) | (28,378) | (29,146) | (29,905) |
| H | Large Load Flexibility | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| I | Largest Loss-of-Source Contingency | (1,310) | (1,310) | (1,310) | (1,310) | (1,310) | (1,310) | (1,310) | (1,310) | (1,310) |
| J | **Total Capability Requirement (G+H+I)** | (26,230) | (26,626) | (27,125) | (27,675) | (28,336) | (28,981) | (29,688) | (30,456) | (31,215) |
| | | | | | | | | | | |
| K | **Statewide System Margin (F+J)** | 1,831 | 1,331 | 832 | 282 | (378) | (1,023) | (1,730) | (2,498) | (3,257) |
| L | SCRs (7), (8) | 721 | 721 | 721 | 721 | 721 | 721 | 721 | 721 | 721 |
| M | **Statewide System Margin with SCR (K+L)** | 2,552 | 2,052 | 1,553 | 1,003 | 343 | (302) | (1,009) | (1,777) | (2,536) |
| N | Operating Reserve | (1,310) | (1,310) | (1,310) | (1,310) | (1,310) | (1,310) | (1,310) | (1,310) | (1,310) |
| O | **Statewide System Margin with Full Operating Reserve (M+N) (4)** | 1,242 | 742 | 243 | (307) | (967) | (1,612) | (2,319) | (3,087) | (3,846) |

Notes:

1. Reflects the 2025 Gold Book existing winter capacity plus projected additions and deactivations.
2. Reflects the derates for generating resources. For this evaluation land-based wind generation is assumed to have a capability of 15% of the total nameplate, off-shore wind at 20% of the total nameplate. Solar generation is assumed offline for the winter peak hour. Includes derates for thermal resources based on NERC five-year class average EFORd data published October 2024 (https://www.nerc.com/pa/RAPA/gads/Pages/Reports.aspx). Also includes a reduction of 310 MW based on the impact of Correlated Derates to DMNC on resources impacted by the Modeling Improvements for “Capacity Accreditation project – Correlated Derates” requirements are reflected in the NYISO ICAP manual and the Market Services Tariff Section 5.
3. Interchanges are based on ERAG MMWG values and firm transactions. Includes a 175 MW reduction in capacity sales from PJM. Includes external imports from the Cross-Sound Cable in accordance with planned imports through early 2027, but starting in summer 2027 this import is assumed at 0 MW.
4. For informational purposes.
5. Reflects the 2025 Gold Book Forecast.
6. Includes all gas only units that do not have a firm gas contract. Also includes reductions in units with duct burner capabilities.
7. SCRs are not applied for transmission security analysis of normal operations, but are included for emergency operations.
8. Includes a derate of 305 MW for SCRs.

### Figure 35: Summer Peak Statewide System Margin Calculation – Planned System, Flexible Large Loads Online

| Line | Item | Summer Peak - Expected Summer Weather, Normal Transfer Criteria (MW) | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 |
| A | NYCA Generation (1) | 37,705 | 40,483 | 41,787 | 41,787 | 41,787 | 41,333 | 41,333 | 41,333 | 41,333 |
| B | NYCA Generation Unavailability (2) | (6,700) | (9,133) | (10,302) | (10,328) | (10,353) | (10,332) | (10,357) | (10,357) | (10,383) |
| C | Temperature Based Generation Derates | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| D | External Area Interchanges (3) | 3,208 | 2,919 | 2,919 | 2,919 | 2,919 | 2,919 | 2,919 | 2,919 | 2,919 |
| E | **Total Resources (A+B+C+D)** | 34,212 | 34,269 | 34,405 | 34,379 | 34,353 | 33,920 | 33,894 | 33,894 | 33,869 |
| | | | | | | | | | | |
| F | Demand Forecast (5) | (31,990) | (32,275) | (32,383) | (32,571) | (32,845) | (33,119) | (33,442) | (33,786) | (34,084) |
| G | Largest Loss-of-Source Contingency | (1,310) | (1,310) | (1,310) | (1,310) | (1,310) | (1,310) | (1,310) | (1,310) | (1,310) |
| H | **Total Capability Requirement (F+G)** | (33,300) | (33,585) | (33,693) | (33,881) | (34,155) | (34,429) | (34,752) | (35,096) | (35,394) |
| | | | | | | | | | | |
| I | **Statewide System Margin (E+H)** | 912 | 684 | 712 | 498 | 198 | (509) | (858) | (1,202) | (1,525) |
| J | Higher Demand Impact | (600) | (1,170) | (1,650) | (2,050) | (2,330) | (2,520) | (2,660) | (2,830) | (3,160) |
| K | **Higher Demand Statewide System Margin (I+J)** | 312 | (486) | (938) | (1,552) | (2,132) | (3,029) | (3,518) | (4,032) | (4,685) |
| L | SCRs (6), (7) | 804 | 804 | 804 | 804 | 804 | 804 | 804 | 804 | 804 |
| M | **Statewide System Margin with SCR (K+L)** | 1,116 | 318 | (135) | (748) | (1,328) | (2,225) | (2,714) | (3,228) | (3,882) |
| N | Operating Reserve | (1,310) | (1,310) | (1,310) | (1,310) | (1,310) | (1,310) | (1,310) | (1,310) | (1,310) |
| O | **Statewide System Margin with Full Operating Reserve (M+N) (4)** | (194) | (992) | (1,445) | (2,058) | (2,638) | (3,535) | (4,024) | (4,538) | (5,192) |

Notes:

1. Reflects the 2025 Gold Book existing summer capacity plus projected additions and deactivations.
2. Reflects the derates for generating resources. For this evaluation land-based wind generation is assumed to have a capability of 5% of the total nameplate, off-shore wind at 15% of the total nameplate, solar generation is based on the ratio of solar PV nameplate capacity (2025 Gold Book Table I-9a) and solar PV peak reductions (2025 Gold Book Table I-9c). Derates for run-of-river hydro are included as well as the Oswego Export limit for all lines in-service. Includes derates for thermal resources based on NERC five-year class average EFORd data published October 2024 (https://www.nerc.com/pa/RAPA/gads/Pages/Reports.aspx). Also includes a reduction of 310 MW based on the impact of Correlated Derates to DMNC on resources impacted by the Modeling Improvements for "Capacity Accreditation project – Correlated Derates" requirements are reflected in the NYISO ICAP manual and the Market Services Tariff Section 5.
3. Interchanges are based on ERAG MMWG values and firm transactions. Includes a 175 MW reduction in capacity sales from PJM. Includes external imports from the Cross-Sound Cable in accordance with planned imports through early 2027, but starting in summer 2027 this import is assumed at 0 MW.
4. For informational purposes.
5. Reflects the 2025 Gold Book Forecast.
6. SCRs are not applied for transmission security analysis of normal operations, but are included for emergency operations.
7. Includes a derate of 401 MW for SCRs

### Figure 36: Winter Statewide System Margin Calculation – Planned System Flexible Large Loads Online

| Line | Item | Winter Peak - Baseline Expected Winter Weather, Normal Transfer Criteria (MW) | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | | **2026-27** | **2027-28** | **2028-29** | **2029-30** | **2030-31** | **2031-32** | **2032-33** | **2033-34** | **2034-35** |
| A | NYCA Generation (1) | 42,115 | 43,484 | 43,864 | 43,864 | 43,407 | 43,407 | 43,407 | 43,407 | 43,407 |
| B | NYCA Generation Unavailability (2) | (8,575) | (9,759) | (10,139) | (10,139) | (10,139) | (10,139) | (10,139) | (10,139) | (10,139) |
| C | Unavailability of Non-Firm Gas (6) | (6,328) | (6,328) | (6,328) | (6,328) | (5,870) | (5,870) | (5,870) | (5,870) | (5,870) |
| D | Temperature Based Generation Derates | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| E | External Area Interchanges (3) | 849 | 560 | 560 | 560 | 560 | 560 | 560 | 560 | 560 |
| F | **Total Resources (A+B+C+D+E)** | 28,061 | 27,957 | 27,957 | 27,957 | 27,958 | 27,958 | 27,958 | 27,958 | 27,958 |
| | | | | | | | | | | |
| G | Demand Forecast (5) | (24,920) | (25,316) | (25,815) | (26,365) | (27,026) | (27,671) | (28,378) | (29,146) | (29,905) |
| H | Large Load Flexibility | 685 | 685 | 685 | 685 | 685 | 685 | 685 | 685 | 685 |
| I | Largest Loss-of-Source Contingency | (1,310) | (1,310) | (1,310) | (1,310) | (1,310) | (1,310) | (1,310) | (1,310) | (1,310) |
| J | **Total Capability Requirement (G+H+I)** | (25,545) | (25,941) | (26,440) | (26,990) | (27,651) | (28,296) | (29,003) | (29,771) | (30,530) |
| | | | | | | | | | | |
| K | **Statewide System Margin (F+J)** | 2,516 | 2,016 | 1,517 | 967 | 307 | (338) | (1,045) | (1,813) | (2,572) |
| L | SCRs (7), (8) | 721 | 721 | 721 | 721 | 721 | 721 | 721 | 721 | 721 |
| M | **Statewide System Margin with SCR (K+L)** | 3,237 | 2,737 | 2,238 | 1,688 | 1,028 | 383 | (324) | (1,092) | (1,851) |
| N | Operating Reserve | (1,310) | (1,310) | (1,310) | (1,310) | (1,310) | (1,310) | (1,310) | (1,310) | (1,310) |
| O | **Statewide System Margin with Full Operating Reserve (M+N) (4)** | 1,927 | 1,427 | 928 | 378 | (282) | (927) | (1,634) | (2,402) | (3,161) |

Notes:

1. Reflects the 2025 Gold Book existing winter capacity plus projected additions and deactivations.
2. Reflects the derates for generating resources. For this evaluation land-based wind generation is assumed to have a capability of 15% of the total nameplate, off-shore wind at 20% of the total nameplate. Solar generation is assumed offline for the winter peak hour. Includes derates for thermal resources based on NERC five-year class average EFORd data published October 2024 (https://www.nerc.com/pa/RAPA/gads/Pages/Reports.aspx). Also includes a reduction of 310 MW based on the impact of Correlated Derates to DMNC on resources impacted by the Modeling Improvements for "Capacity Accreditation project – Correlated Derates" requirements are reflected in the NYISO ICAP manual and the Market Services Tariff Section 5.

3. Interchanges are based on ERAG MMWG values and firm transactions. Includes a 175 MW reduction in capacity sales from PJM. Includes external imports from the Cross-Sound Cable in accordance with planned imports through early 2027, but starting in summer 2027 this import is assumed at 0 MW.
4. For informational purposes.
5. Reflects the 2025 Gold Book Forecast.
6. Includes all gas only units that do not have a firm gas contract. Also includes reductions in units with duct burner capabilities.
7. SCRs are not applied for transmission security analysis of normal operations, but are included for emergency operations.
8. Includes a derate of 305 MW for SCRs.

**Figure 37: Summer Statewide System Margin Calculation – Status Quo System**

| Line | Item | Summer Peak - Expected Summer Weather, Normal Transfer Criteria (MW) | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 |
| A | NYCA Generation (1) | 37,363 | 37,263 | 37,263 | 37,263 | 37,263 | 36,809 | 36,809 | 36,809 | 36,809 |
| B | NYCA Generation Unavailability (2) | (6,406) | (6,408) | (6,413) | (6,419) | (6,425) | (6,383) | (6,389) | (6,389) | (6,395) |
| C | Temperature Based Generation Derates | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| D | External Area Interchanges (3) | 1,958 | 1,669 | 1,669 | 1,669 | 1,669 | 1,669 | 1,669 | 1,669 | 1,669 |
| E | **Total Resources (A+B+C+D)** | 32,915 | 32,525 | 32,519 | 32,513 | 32,507 | 32,094 | 32,088 | 32,088 | 32,083 |
| | | | | | | | | | | |
| F | Demand Forecast (5) | (31,305) | (31,590) | (31,698) | (31,886) | (32,160) | (32,434) | (32,757) | (33,101) | (33,399) |
| G | Largest Loss-of-Source Contingency | (1,310) | (1,310) | (1,310) | (1,310) | (1,310) | (1,310) | (1,310) | (1,310) | (1,310) |
| H | **Total Capability Requirement (F+G)** | (32,615) | (32,900) | (33,008) | (33,196) | (33,470) | (33,744) | (34,067) | (34,411) | (34,709) |
| | | | | | | | | | | |
| I | **Statewide System Margin (E+H)** | 300 | (375) | (489) | (683) | (963) | (1,650) | (1,979) | (2,323) | (2,626) |
| J | Higher Demand Impact | (600) | (1,170) | (1,650) | (2,050) | (2,330) | (2,520) | (2,660) | (2,830) | (3,160) |
| K | **Higher Demand Statewide System Margin (I+J)** | (300) | (1,545) | (2,139) | (2,733) | (3,293) | (4,170) | (4,639) | (5,153) | (5,786) |
| L | SCRs (6), (7) | 804 | 804 | 804 | 804 | 804 | 804 | 804 | 804 | 804 |
| M | **Statewide System Margin with SCR (K+L)** | 503 | (742) | (1,336) | (1,929) | (2,489) | (3,366) | (3,835) | (4,349) | (4,983) |
| N | Operating Reserve | (1,310) | (1,310) | (1,310) | (1,310) | (1,310) | (1,310) | (1,310) | (1,310) | (1,310) |
| O | **Statewide System Margin with Full Operating Reserve (M+N) (4)** | (807) | (2,052) | (2,646) | (3,239) | (3,799) | (4,676) | (5,145) | (5,659) | (6,293) |

Notes:

1. Reflects the 2025 Gold Book existing summer capacity plus projected additions and deactivations.
2. Reflects the derates for generating resources. For this evaluation land-based wind generation is assumed to have a capability of 5% of the total nameplate, off-shore wind at 15% of the total nameplate, solar generation is based on the ratio of solar PV nameplate capacity (2025 Gold Book Table I-9a) and solar PV peak reductions (2025 Gold Book Table I-9c). Derates for run-of-river hydro are included as well as the Oswego Export limit for all lines in-service. Includes derates for thermal resources based on NERC five-year class average EFORd data published October 2024 (https://www.nerc.com/pa/RAPA/gads/Pages/Reports.aspx). Also includes a reduction of 310 MW based on the impact of Correlated Derates to DMNC on resources impacted by the Modeling Improvements for “Capacity Accreditation project – Correlated Derates” requirements are reflected in the NYISO ICAP manual and the Market Services Tariff Section 5.
3. Interchanges are based on ERAG MMWG values and firm transactions. Includes a 175 MW reduction in capacity sales from PJM. Includes external imports from the Cross-Sound Cable in accordance with planned imports through early 2027, but starting in summer 2027 this import is assumed at 0 MW.
4. For informational purposes.
5. Reflects the 2025 Gold Book Forecast.
6. SCRs are not applied for transmission security analysis of normal operations, but are included for emergency operations.
7. Includes a derate of 401 MW for SCRs

### Figure 38: Winter Statewide System Margin Calculation – Status Quo System

| Line | Item | Winter Peak - Baseline Expected Winter Weather, Normal Transfer Criteria (MW) | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | | 2026-27 | 2027-28 | 2028-29 | 2029-30 | 2030-31 | 2031-32 | 2032-33 | 2033-34 | 2034-35 |
| A | NYCA Generation (1) | 39,440 | 39,323 | 39,323 | 39,323 | 38,865 | 38,865 | 38,865 | 38,865 | 38,865 |
| B | NYCA Generation Unavailability (2) | (6,162) | (6,150) | (6,150) | (6,150) | (6,149) | (6,149) | (6,149) | (6,149) | (6,149) |
| C | Unavailability of Non-Firm Gas (6) | (6,328) | (6,328) | (6,328) | (6,328) | (5,870) | (5,870) | (5,870) | (5,870) | (5,870) |
| D | Temperature Based Generation Derates | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| E | External Area Interchanges (3) | 849 | 560 | 560 | 560 | 560 | 560 | 560 | 560 | 560 |
| F | **Total Resources (A+B+C+D+E)** | 27,799 | 27,406 | 27,406 | 27,406 | 27,406 | 27,406 | 27,406 | 27,406 | 27,406 |
| | | | | | | | | | | |
| G | Demand Forecast (5) | (24,920) | (25,316) | (25,815) | (26,365) | (27,026) | (27,671) | (28,378) | (29,146) | (29,905) |
| H | Large Load Flexibility | 685 | 685 | 685 | 685 | 685 | 685 | 685 | 685 | 685 |
| I | Largest Loss-of-Source Contingency | (1,310) | (1,310) | (1,310) | (1,310) | (1,310) | (1,310) | (1,310) | (1,310) | (1,310) |
| J | **Total Capability Requirement (G+H+I)** | (25,545) | (25,941) | (26,440) | (26,990) | (27,651) | (28,296) | (29,003) | (29,771) | (30,530) |
| | | | | | | | | | | |
| K | **Statewide System Margin (F+J)** | 2,254 | 1,465 | 966 | 416 | (245) | (890) | (1,597) | (2,365) | (3,124) |
| L | SCRs (7), (8) | 721 | 721 | 721 | 721 | 721 | 721 | 721 | 721 | 721 |
| M | **Statewide System Margin with SCR (K+L)** | 2,975 | 2,185 | 1,686 | 1,136 | 476 | (169) | (876) | (1,644) | (2,403) |
| N | Operating Reserve | (1,310) | (1,310) | (1,310) | (1,310) | (1,310) | (1,310) | (1,310) | (1,310) | (1,310) |
| O | **Statewide System Margin with Full Operating Reserve (M+N) (4)** | 1,665 | 875 | 376 | (174) | (834) | (1,479) | (2,186) | (2,954) | (3,713) |

Notes:

1. Reflects the 2025 Gold Book existing winter capacity plus projected additions and deactivations.
2. Reflects the derates for generating resources. For this evaluation land-based wind generation is assumed to have a capability of 15% of the total nameplate, off-shore wind at 20% of the total nameplate. Solar generation is assumed offline for the winter peak hour. Includes derates for thermal resources based on NERC five-year class average EFORd data published October 2024 (https://www.nerc.com/pa/RAPA/gads/Pages/Reports.aspx). Also includes a reduction of 310 MW based on forecasted impacts to DMNC.
3. Interchanges are based on ERAG MMWG values and firm transactions. Includes a 175 MW reduction in capacity sales from PJM. Includes an additional 289MW tie line contract in 2026 only.
4. For informational purposes.
5. Reflects the 2025 Gold Book Forecast.
6. Includes all gas only units that do not have a firm gas contract. Also includes reductions in units with duct burner capabilities.
7. SCRs are not applied for transmission security analysis of normal operations, but are included for emergency operations.
8. Includes a derate of 305 MW for SCRs.

### Lower Hudson Valley (Zones G-J)

The Lower Hudson Valley or southeastern New York (SENY) locality comprises Zones G-J and includes the electrical connections to the RECO load in PJM. To determine the transmission security margin for this area, the NYISO determines the most limiting combination of two non-simultaneous contingency events (N-1-1) to the transmission security margin. As the system changes, the limiting contingency combination may also change.

In summer throughout the study period, the limiting contingency combination is the loss of Knickerbocker – Pleasant Valley 345 kV followed by the loss of Athens-Van Wagner 345 kV (91). The limiting contingency combination for winter throughout the study period is the loss of Ravenswood 3 followed by the loss of Pleasant Valley-Wood St. 345 kV (F30/F31).

Figure 40 and Figure 42 show the calculation of the summer and winter Lower Hudson Valley transmission security margin for baseline expected weather, expected load conditions for the statewide coincident peak hour with normal transfer criteria. This STAR finds that the Lower Hudson Valley is deficient beginning in summer 2030. Under the demand range for expected weather, the Lower Hudson Valley deficiency in 2030 is 195 MW over 3 hours (729 MWh). This deficiency is further exacerbated through time without any additional capabilities added to this locality.

### Figure 39: Summer Peak Lower Hudson Valley Margin Calculation – Status Quo System

| Summer Peak - Expected Weather, Normal Transfer Criteria (MW) | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| **Line** | **Item** | **2026** | **2027** | **2028** | **2029** | **2030** | **2031** | **2032** | **2033** | **2034** |
| A | G-J Demand Forecast | (15,034) | (15,103) | (15,145) | (15,176) | (15,205) | (15,280) | (15,401) | (15,515) | (15,652) |
| B | RECO Demand | (407) | (407) | (407) | (404) | (404) | (404) | (404) | (404) | (417) |
| C | **Total Demand (A+B)** | (15,441) | (15,510) | (15,552) | (15,580) | (15,609) | (15,684) | (15,805) | (15,919) | (16,069) |
| | | | | | | | | | | |
| D | UPNY-SENY Limit (3) | 4,700 | 4,700 | 4,700 | 4,700 | 4,700 | 4,700 | 4,700 | 4,700 | 4,700 |
| E | ABC PARs to J | (11) | (11) | (11) | (11) | (11) | (11) | (11) | (11) | (11) |
| F | K - SENY | 47 | (274) | (274) | (298) | (350) | (456) | (508) | (565) | (616) |
| G | **Total SENY AC Import (D+E+F)** | 4,736 | 4,415 | 4,415 | 4,391 | 4,339 | 4,233 | 4,181 | 4,124 | 4,073 |
| | | | | | | | | | | |
| H | Loss of Source Contingency | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| I | **Resource Need (C+G+H)** | (10,705) | (11,095) | (11,137) | (11,189) | (11,270) | (11,451) | (11,624) | (11,795) | (11,996) |
| | | | | | | | | | | |
| J | G-J Generation (1) | 12,849 | 12,849 | 12,849 | 12,849 | 12,849 | 12,439 | 12,439 | 12,439 | 12,439 |
| K | G-J Generation Unavailability (2) | (1,230) | (1,230) | (1,230) | (1,230) | (1,230) | (1,188) | (1,188) | (1,188) | (1,188) |
| L | Temperature Based Generation Derates | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| M | Net ICAP External Imports (4) | 140 | 140 | 140 | 140 | 140 | 140 | 140 | 140 | 140 |
| N | **Total Resources Available (J+K+L+M)** | 11,759 | 11,759 | 11,759 | 11,759 | 11,759 | 11,392 | 11,392 | 11,392 | 11,392 |
| | | | | | | | | | | |
| O | **Transmission Security Margin (I+N)** | 1,054 | 664 | 622 | 570 | 489 | (59) | (233) | (404) | (604) |
| P | Higher Demand Impact | (142) | (236) | (362) | (509) | (684) | (791) | (865) | (971) | (1,067) |
| Q | **Higher Demand Transmission Security Margin (O+P)** | 912 | 428 | 260 | 61 | (195) | (850) | (1,098) | (1,375) | (1,671) |
| R | Noncoincident Peak Demand Impact | (246) | (246) | (247) | (247) | (247) | (248) | (250) | (252) | (256) |
| S | **Noncoincident Peak Transmission Security Margin (O+R)** | 808 | 418 | 375 | 323 | 242 | (307) | (483) | (656) | (860) |

Notes:

1. Reflects the 2025 Gold Book existing summer capacity plus projected additions and deactivations.
2. Reflects the derates for generating resources. For this evaluation land-based wind generation is assumed to have a capability of 5% of the total nameplate, off-shore wind at 15% of the total nameplate,
3. Limits for 2026 through 2029 are based on summer peak 2029 representations evaluated in the 2024 RNA. Limits for 2030 through 2034 are based on summer peak 2034 representations evaluated in the
4. Interchanges are based on ERAG MMWG values and firm transactions. Includes a 175 MW reduction in capacity sales from PJM.

### Figure 40: Summer Peak Lower Hudson Valley Margin Calculation – Planned System

| Summer Peak - Expected Weather, Normal Transfer Criteria (MW) | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| **Line** | **Item** | **2026** | **2027** | **2028** | **2029** | **2030** | **2031** | **2032** | **2033** | **2034** |
| A | G-J Demand Forecast | (15,034) | (15,103) | (15,145) | (15,176) | (15,205) | (15,280) | (15,401) | (15,515) | (15,652) |
| B | RECO Demand | (407) | (407) | (407) | (404) | (404) | (404) | (404) | (404) | (417) |
| C | **Total Demand (A+B)** | (15,441) | (15,510) | (15,552) | (15,580) | (15,609) | (15,684) | (15,805) | (15,919) | (16,069) |
| | | | | | | | | | | |
| D | UPNY-SENY Limit (3) | 4,700 | 4,700 | 4,700 | 4,700 | 4,500 | 4,500 | 4,500 | 4,500 | 4,500 |
| E | ABC PARs to J | (11) | (11) | (11) | (11) | (11) | (11) | (11) | (11) | (11) |
| F | K - SENY | 47 | (184) | (91) | (115) | (168) | (273) | (326) | (383) | (433) |
| G | **Total SENY AC Import (D+E+F)** | 4,736 | 4,505 | 4,598 | 4,574 | 4,321 | 4,216 | 4,163 | 4,106 | 4,056 |
| | | | | | | | | | | |
| H | Loss of Source Contingency | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| I | **Resource Need (C+G+H)** | (10,705) | (11,005) | (10,954) | (11,006) | (11,288) | (11,468) | (11,642) | (11,813) | (12,013) |
| | | | | | | | | | | |
| J | G-J Generation (1) | 12,894 | 13,710 | 13,710 | 13,710 | 13,710 | 13,300 | 13,300 | 13,300 | 13,300 |
| K | G-J Generation Unavailability (2) | (1,269) | (2,004) | (2,005) | (2,005) | (2,005) | (1,963) | (1,963) | (1,964) | (1,964) |
| L | Temperature Based Generation Derates | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| M | Net ICAP External Imports (4) | 1,390 | 1,390 | 1,390 | 1,390 | 1,390 | 1,390 | 1,390 | 1,390 | 1,390 |
| N | **Total Resources Available (J+K+L+M)** | 13,014 | 13,096 | 13,095 | 13,095 | 13,095 | 12,727 | 12,727 | 12,726 | 12,726 |
| | | | | | | | | | | |
| O | **Transmission Security Margin (I+N)** | 2,309 | 2,090 | 2,141 | 2,089 | 1,807 | 1,259 | 1,085 | 914 | 713 |
| P | Higher Demand Impact | (142) | (236) | (362) | (509) | (684) | (791) | (865) | (971) | (1,067) |
| Q | **Higher Demand Transmission Security Margin (O+P)** | 2,167 | 1,854 | 1,779 | 1,580 | 1,123 | 468 | 220 | (57) | (354) |
| R | Noncoincident Peak Demand Impact | (246) | (246) | (247) | (247) | (247) | (248) | (250) | (252) | (256) |
| S | **Noncoincident Peak Transmission Security Margin (O+R)** | 2,063 | 1,844 | 1,894 | 1,842 | 1,560 | 1,011 | 835 | 662 | 457 |

Notes:

1. Reflects the 2025 Gold Book existing summer capacity plus projected additions and deactivations.
2. Reflects the derates for generating resources. For this evaluation land-based wind generation is assumed to have a capability of 5% of the total nameplate, off-shore wind at 15% of the total nameplate, solar generation is based on the ratio of solar PV nameplate capacity (2025 Gold Book Table I-9a) and solar PV peak reductions (2025 Gold Book Table I-9c). Derates for run-of-river hydro are included. Includes derates for thermal resources based on NERC five-year class average EFORd data published October 2024 (https://www.nerc.com/pa/RAPA/gads/Pages/Reports.aspx). Also includes a reduction of 110 MW based on the impact of Correlated Derates to DMNC on resources impacted by the Modeling Improvements for "Capacity Accreditation project – Correlated Derates" requirements are reflected in the NYISO ICAP manual and the Market Services Tariff Section 5.
3. Limits for 2026 through 2029 are based on summer peak 2029 representations evaluated in the 2024 RNA. Limits for 2030 through 2034 are based on summer peak 2034 representations evaluated in the 2024 RNA.
4. Interchanges are based on ERAG MMWG values and firm transactions. Includes a 175 MW reduction in capacity sales from PJM.

## Figure 41: Winter Peak Lower Hudson Valley Margin Calculation – Status Quo System

| Winter Peak - Expected Weather, Normal Transfer Criteria (MW) | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| **Line** | **Item** | **2026-27** | **2027-28** | **2028-29** | **2029-30** | **2030-31** | **2031-32** | **2032-33** | **2033-34** | **2034-35** |
| A | G-J Demand Forecast | (10,714) | (10,835) | (11,044) | (11,229) | (11,437) | (11,682) | (11,944) | (12,248) | (12,588) |
| B | RECO Demand | (246) | (246) | (246) | (236) | (236) | (236) | (236) | (236) | (313) |
| C | **Total Demand (A+B)** | (10,960) | (11,081) | (11,290) | (11,465) | (11,673) | (11,918) | (12,180) | (12,484) | (12,901) |
| | | | | | | | | | | |
| D | UPNY-SENY Limit (3) | 5,300 | 5,300 | 5,300 | 5,300 | 5,300 | 5,300 | 5,300 | 5,300 | 5,300 |
| E | ABC PARs to J | (11) | (11) | (11) | (11) | (11) | (11) | (11) | (11) | (11) |
| F | K - SENY | 47 | 47 | 47 | 47 | 1,013 | 1,013 | 1,013 | 969 | 862 |
| G | **Total SENY AC Import (D+E+F)** | 5,336 | 5,336 | 5,336 | 5,336 | 6,302 | 6,302 | 6,302 | 6,258 | 6,151 |
| | | | | | | | | | | |
| H | Loss of Source Contingency | (973) | (973) | (973) | (973) | (973) | (973) | (973) | (973) | (973) |
| I | **Resource Need (C+G+H)** | (6,597) | (6,718) | (6,927) | (7,102) | (6,344) | (6,589) | (6,851) | (7,199) | (7,723) |
| | | | | | | | | | | |
| J | G-J Generation (1) | 13,580 | 13,580 | 13,580 | 13,580 | 13,169 | 13,169 | 13,169 | 13,169 | 13,169 |
| K | G-J Generation Unavailability (2) | (1,118) | (1,118) | (1,118) | (1,118) | (1,117) | (1,117) | (1,117) | (1,117) | (1,117) |
| L | Shortage of Gas Fuel Supply (4) | (2,719) | (2,719) | (2,719) | (2,719) | (2,308) | (2,308) | (2,308) | (2,308) | (2,308) |
| M | Temperature Based Generation Derates | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| N | Net ICAP External Imports (5) | 140 | 140 | 140 | 140 | 140 | 140 | 140 | 140 | 140 |
| O | **Total Resources Available (J+K+L+M+N)** | 9,883 | 9,883 | 9,883 | 9,883 | 9,883 | 9,883 | 9,883 | 9,883 | 9,883 |
| | | | | | | | | | | |
| P | **Transmission Security Margin (I+O)** | 3,286 | 3,165 | 2,956 | 2,781 | 3,540 | 3,295 | 3,033 | 2,685 | 2,161 |
| Q | Higher Demand Impact | (174) | (257) | (385) | (461) | (618) | (854) | (1,097) | (1,494) | (1,737) |
| R | **Higher Demand Transmission Security Margin (P+Q)** | 3,112 | 2,908 | 2,571 | 2,320 | 2,922 | 2,441 | 1,936 | 1,191 | 424 |
| S | Noncoincident Peak Demand Impact | (34) | (35) | (36) | (37) | (37) | (37) | (38) | (40) | (41) |
| T | **Noncoincident Peak Transmission Security Margin (P+S)** | 3,252 | 3,130 | 2,920 | 2,744 | 3,503 | 3,258 | 2,995 | 2,645 | 2,120 |

Notes:

1. Reflects the 2025 Gold Book existing winter capacity plus projected additions and deactivations.
2. Reflects the derates for generating resources. For this evaluation land-based wind generation is assumed to have a capability of 15% of the total nameplate, off-shore wind at 20% of the total nameplate. Solar generation is assumed offline for the winter peak hour. Includes derates for thermal resources based on NERC five-year class average EFORd data published October 2024 (https://www.nerc.com/pa/RAPA/gads/Pages/Reports.aspx). Also includes a reduction of 110 MW based on the impact of Correlated Derates to DMNC on resources impacted by the Modeling Improvements for "Capacity Accreditation project – Correlated Derates" requirements are reflected in the NYISO ICAP manual and the Market Services Tariff Section 5.
3. Limits for 2026 through 2029 are based on summer peak 2029 representations evaluated in the 2024 RNA. Limits for 2030 through 2034 are based on summer peak 2034 representations evaluated in the 2024 RNA.
4. Includes all gas only units that do not have a firm gas contract.
5. Interchanges are based on ERAG MMWG values and firm transactions. Includes a 175 MW reduction in capacity sales from PJM.

## Figure 42: Winter Peak Lower Hudson Valley Margin Calculation – Planned System

| Winter Peak - Expected Weather, Normal Transfer Criteria (MW) | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| **Line** | **Item** | **2026-27** | **2027-28** | **2028-29** | **2029-30** | **2030-31** | **2031-32** | **2032-33** | **2033-34** | **2034-35** |
| A | G-J Demand Forecast | (10,714) | (10,835) | (11,044) | (11,229) | (11,437) | (11,682) | (11,944) | (12,248) | (12,588) |
| B | RECO Demand | (246) | (246) | (246) | (236) | (236) | (236) | (236) | (236) | (313) |
| C | **Total Demand (A+B)** | (10,960) | (11,081) | (11,290) | (11,465) | (11,673) | (11,918) | (12,180) | (12,484) | (12,901) |
| | | | | | | | | | | |
| D | UPNY-SENY Limit (3) | 5,300 | 5,300 | 5,300 | 5,300 | 5,700 | 5,700 | 5,700 | 5,700 | 5,700 |
| E | ABC PARs to J | (11) | (11) | (11) | (11) | (11) | (11) | (11) | (11) | (11) |
| F | K - SENY | 47 | 47 | 47 | 47 | 1,013 | 1,013 | 1,013 | 1,013 | 1,013 |
| G | **Total SENY AC Import (D+E+F)** | 5,336 | 5,336 | 5,336 | 5,336 | 6,702 | 6,702 | 6,702 | 6,702 | 6,702 |
| | | | | | | | | | | |
| H | Loss of Source Contingency | (973) | (973) | (973) | (973) | (973) | (973) | (973) | (973) | (973) |
| I | **Resource Need (C+G+H)** | (6,597) | (6,718) | (6,927) | (7,102) | (5,944) | (6,189) | (6,451) | (6,755) | (7,172) |
| | | | | | | | | | | |
| J | G-J Generation (1) | 14,441 | 14,441 | 14,441 | 14,441 | 14,030 | 14,030 | 14,030 | 14,030 | 14,030 |
| K | G-J Generation Unavailability (2) | (1,816) | (1,816) | (1,816) | (1,816) | (1,815) | (1,815) | (1,815) | (1,815) | (1,815) |
| L | Shortage of Gas Fuel Supply (4) | (2,719) | (2,719) | (2,719) | (2,719) | (2,308) | (2,308) | (2,308) | (2,308) | (2,308) |
| M | Temperature Based Generation Derates | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| N | Net ICAP External Imports (5) | 140 | 140 | 140 | 140 | 140 | 140 | 140 | 140 | 140 |
| O | **Total Resources Available (J+K+L+M+N)** | 10,046 | 10,046 | 10,046 | 10,046 | 10,047 | 10,047 | 10,047 | 10,047 | 10,047 |
| | | | | | | | | | | |
| P | **Transmission Security Margin (I+O)** | 3,449 | 3,328 | 3,119 | 2,944 | 4,103 | 3,858 | 3,596 | 3,292 | 2,875 |
| Q | Higher Demand Impact | (174) | (257) | (385) | (461) | (618) | (854) | (1,097) | (1,494) | (1,737) |
| R | **Higher Demand Transmission Security Margin (P+Q)** | 3,275 | 3,071 | 2,734 | 2,483 | 3,485 | 3,004 | 2,499 | 1,798 | 1,138 |
| S | Noncoincident Peak Demand Impact | (34) | (35) | (36) | (37) | (37) | (37) | (38) | (40) | (41) |
| T | **Noncoincident Peak Transmission Security Margin (P+S)** | 3,415 | 3,293 | 3,083 | 2,907 | 4,066 | 3,821 | 3,558 | 3,252 | 2,834 |

Notes:

1. Reflects the 2025 Gold Book existing winter capacity plus projected additions and deactivations.
2. Reflects the derates for generating resources. For this evaluation land-based wind generation is assumed to have a capability of 15% of the total nameplate, off-shore wind at 20% of the total nameplate. Solar generation is assumed offline for the winter peak hour. Includes derates for thermal resources based on NERC five-year class average EFORd data published October 2024 (https://www.nerc.com/pa/RAPA/gads/Pages/Reports.aspx). Also includes a reduction of 110 MW based on the impact of Correlated Derates to DMNC on resources impacted by the Modeling Improvements for "Capacity Accreditation project – Correlated Derates" requirements are reflected in the NYISO ICAP manual and the Market Services Tariff Section 5.

3. Limits for 2026 through 2029 are based on summer peak 2029 representations evaluated in the 2024 RNA. Limits for 2030 through 2034 are based on summer peak 2034 representations evaluated in the 2024 RNA.
4. Includes all gas only units that do not have a firm gas contract.
5. Interchanges are based on ERAG MMWG values and firm transactions. Includes a 175 MW reduction in capacity sales from PJM.

## New York City (Zone J)

The New York City locality comprises Zone J. Within the Con Edison service territory, the 345 kV transmission system, along with specific portions of the 138 kV transmission system, is designed for the occurrence of two non-simultaneous contingencies and a return to normal (N-1-1-0).[23] Therefore, unlike the Lower Hudson Valley and Long Island localities, the New York City transmission security margin is calculated based on the most limiting N-1-1-0 contingency combination. As the system changes, the limiting contingency combination may also change.

Starting in summer 2026 and continuing throughout the study period, the limiting contingency combination is the loss of the CHPE HVDC cable followed by the loss of Ravenswood 3. In winter 2026-2027 through winter 2029-2030, the limiting contingency combination is the loss of Ravenswood 3 followed by the loss of Mott Haven – Rainey 345 kV (Q12). Starting in winter 2030-2031 and continuing throughout the remainder of the study period, the limiting contingency combination changes to the loss of Ravenswood 3 followed by the loss of Bayonne. The CHPE cable is not included in limiting contingencies in winter due to the assumption that following the in service status of CHPE, it is scheduled at 0 MW for the winter seasons.

This assessment recognizes that there is a range in the demand forecast driven by uncertainties in key assumptions, such as population and economic growth, energy efficiency, the installation of behind-the-meter renewable energy resources, and electric vehicle adoption and charging patterns. The forecasted summer peak demand in New York City has a range of 460 MW in 2026 growing to 1,360 MW in 2030, primarily driven by assumptions in electrification of transportation and buildings. Baseline demand lies approximately in the middle of the range and is used for the baseline margin (line-item L) in Figure 44. The upper range of this forecast band is used for the higher demand margin (line-item N). The assumed available supply has also been adjusted to account for expected reductions of 110 MW in generators' dependable maximum net capability (DMNC) and 175 MW reduction in capacity sales from PJM.

23 https://www.coned.com/-/media/files/coned/documents/business-partners/transmission-planning/transmission-planning-criteria.pdf

**Figure 43: Summer Peak New York City Transmission Security Margin Calculation – Status Quo System**

| Summer Peak - Baseline Expected Weather, Normal Transfer Criteria (MW) | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| **Line** | **Item** | **2026** | **2027** | **2028** | **2029** | **2030** | **2031** | **2032** | **2033** | **2034** |
| A | **Zone J Demand Forecast** | (10,790) | (10,820) | (10,840) | (10,860) | (10,880) | (10,930) | (11,010) | (11,080) | (11,170) |
| | | | | | | | | | | |
| B | I+K to J (3) | 3,900 | 3,900 | 3,900 | 3,900 | 3,900 | 3,900 | 3,900 | 3,900 | 3,900 |
| C | ABC PARs to J | (11) | (11) | (11) | (11) | (11) | (11) | (11) | (11) | (11) |
| D | **Total J AC Import (B+C)** | 3,889 | 3,889 | 3,889 | 3,889 | 3,889 | 3,889 | 3,889 | 3,889 | 3,889 |
| | | | | | | | | | | |
| E | Loss of Source Contingency | (985) | (985) | (985) | (985) | (985) | (985) | (985) | (985) | (985) |
| F | **Resource Need (A+D+E)** | (7,886) | (7,916) | (7,936) | (7,956) | (7,976) | (8,026) | (8,106) | (8,176) | (8,266) |
| | | | | | | | | | | |
| G | J Generation (1) | 8,108 | 8,108 | 8,108 | 8,108 | 8,108 | 7,698 | 7,698 | 7,698 | 7,698 |
| H | J Generation Unavailability (2) | (772) | (772) | (772) | (772) | (772) | (730) | (730) | (730) | (730) |
| I | Temperature Based Generation Derates | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| J | Net ICAP External Imports (4) | 140 | 140 | 140 | 140 | 140 | 140 | 140 | 140 | 140 |
| K | **Total Resources Available (G+H+I+J)** | 7,476 | 7,476 | 7,476 | 7,476 | 7,476 | 7,109 | 7,109 | 7,109 | 7,109 |
| | | | | | | | | | | |
| L | **Baseline Transmission Security Margin (F+K)** | (410) | (440) | (460) | (480) | (500) | (917) | (997) | (1,067) | (1,157) |
| M | Higher Demand Impact | (130) | (220) | (330) | (470) | (630) | (720) | (790) | (880) | (960) |
| N | **Higher Demand Transmission Security Margin (L+M)** | (540) | (660) | (790) | (950) | (1,130) | (1,637) | (1,787) | (1,947) | (2,117) |
| O | Noncoincident Peak Demand Impact | (240) | (240) | (240) | (240) | (240) | (240) | (250) | (250) | (250) |
| P | **Noncoincident Peak Transmission Security Margin (L+O)** | (650) | (680) | (700) | (720) | (740) | (1,157) | (1,247) | (1,317) | (1,407) |

Notes:

1. Reflects the 2025 Gold Book existing summer capacity plus projected additions and deactivations.
2. Reflects the derates for generating resources. For this evaluation land-based wind generation is assumed to have a capability of 5% of the total nameplate, off-shore wind at 10% of the total nameplate, solar generation is based on the ratio of solar PV nameplate capacity (2025 Gold Book Table I-9a) and solar PV peak reductions (2025 Gold Book Table I-9c). Includes derates for thermal resources based on NERC five-year class average EFORd data published October 2024 (https://www.nerc.com/pa/RAPA/gads/Pages/Reports.aspx). Also includes a reduction of 110 MW based on the impact of Correlated Derates to DMNC on resources impacted by the Modeling Improvements for "Capacity Accreditation project – Correlated Derates" requirements are reflected in the NYISO ICAP manual and the Market Services Tariff Section 5.

3. Limits for 2026 through 2029 are based on the summer peak 2029 representations evaluated in the 2024 RNA. Limits for 2030 through 2034 are based on the summer peak 2034 representations evaluated in the 2024 RNA.
4. Interchanges are based on ERAG MMWG values and firm transactions. Includes a 175 MW reduction in capacity sales from PJM.

### Figure 44: Summer Peak New York City Transmission Security Margin Calculation – Planned System

| Summer Peak - Expected Weather, Normal Transfer Criteria (MW) | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| **Line** | **Item** | **2026** | **2027** | **2028** | **2029** | **2030** | **2031** | **2032** | **2033** | **2034** |
| A | **Zone J Demand Forecast** | (10,790) | (10,820) | (10,840) | (10,860) | (10,880) | (10,930) | (11,010) | (11,080) | (11,170) |
| | | | | | | | | | | |
| B | I+K to J (3) | 4,700 | 4,700 | 4,700 | 4,700 | 4,800 | 4,800 | 4,800 | 4,800 | 4,800 |
| C | ABC PARs to J | (11) | (11) | (11) | (11) | (11) | (11) | (11) | (11) | (11) |
| D | **Total J AC Import (B+C)** | 4,689 | 4,689 | 4,689 | 4,689 | 4,789 | 4,789 | 4,789 | 4,789 | 4,789 |
| | | | | | | | | | | |
| E | Loss of Source Contingency | (2,235) | (2,235) | (2,235) | (2,235) | (2,235) | (2,235) | (2,235) | (2,235) | (2,235) |
| F | **Resource Need (A+D+E)** | (8,336) | (8,366) | (8,386) | (8,406) | (8,326) | (8,376) | (8,456) | (8,526) | (8,616) |
| | | | | | | | | | | |
| G | J Generation (1) | 8,123 | 8,939 | 8,939 | 8,939 | 8,939 | 8,529 | 8,529 | 8,529 | 8,529 |
| H | J Generation Unavailability (2) | (787) | (1,521) | (1,521) | (1,521) | (1,521) | (1,479) | (1,479) | (1,479) | (1,479) |
| I | Temperature Based Generation Derates | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| J | Net ICAP External Imports (4) | 1,390 | 1,390 | 1,390 | 1,390 | 1,390 | 1,390 | 1,390 | 1,390 | 1,390 |
| K | **Total Resources Available (G+H+I+J)** | 8,726 | 8,808 | 8,808 | 8,808 | 8,808 | 8,440 | 8,440 | 8,440 | 8,440 |
| | | | | | | | | | | |
| L | **Baseline Transmission Security Margin (F+K)** | 390 | 442 | 422 | 402 | 482 | 64 | (16) | (86) | (176) |
| M | Higher Demand Impact | (130) | (220) | (330) | (470) | (630) | (720) | (790) | (880) | (960) |
| N | **Higher Demand Transmission Security Margin (L+M)** | 260 | 222 | 92 | (68) | (148) | (656) | (806) | (966) | (1,136) |
| O | Noncoincident Peak Demand Impact | (240) | (240) | (240) | (240) | (240) | (240) | (250) | (250) | (250) |
| P | **Noncoincident Peak Transmission Security Margin (L+O)** | 150 | 202 | 182 | 162 | 242 | (176) | (266) | (336) | (426) |

Notes:

1. Reflects the 2025 Gold Book existing summer capacity plus projected additions and deactivations.
2. Reflects the derates for generating resources. For this evaluation land-based wind generation is assumed to have a capability of 5% of the total nameplate, off-shore wind at 10% of the total nameplate, solar generation is based on the ratio of solar PV nameplate capacity (2025 Gold Book Table I-9a) and solar PV peak reductions (2025 Gold Book Table I-9c). Includes derates for thermal resources based on NERC five-year class average EFORd data published October 2024 (https://www.nerc.com/pa/RAPA/gads/Pages/Reports.aspx). Also includes a reduction of 110 MW based on the impact of Correlated Derates to DMNC on resources impacted by the Modeling Improvements for "Capacity Accreditation project – Correlated Derates" requirements are reflected in the NYISO ICAP manual and the Market Services Tariff Section 5.
3. Limits for 2026 through 2029 are based on the summer peak 2029 representations evaluated in the 2024 RNA. Limits for 2030 through 2034 are based on the summer peak 2034 representations evaluated in the 2024 RNA.
4. Interchanges are based on ERAG MMWG values and firm transactions. Includes a 175 MW reduction in capacity sales from PJM.

**Figure 45: Winter Peak New York City Transmission Security Margin Calculation – Status Quo System**

| Winter Peak - Baseline Expected Weather, Normal Transfer Criteria (MW) | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| **Line** | **Item** | **2026-27** | **2027-28** | **2028-29** | **2029-30** | **2030-31** | **2031-32** | **2032-33** | **2033-34** | **2034-35** |
| A | **Zone J Demand Forecast** | (7,580) | (7,650) | (7,800) | (7,930) | (8,070) | (8,240) | (8,410) | (8,610) | (8,830) |
| | | | | | | | | | | |
| B | I+K to J (3) | 3,900 | 3,900 | 3,900 | 3,900 | 3,900 | 3,900 | 3,900 | 3,900 | 3,900 |
| C | ABC PARs to J | (11) | (11) | (11) | (11) | (11) | (11) | (11) | (11) | (11) |
| D | **Total J AC Import (B+C)** | 3,889 | 3,889 | 3,889 | 3,889 | 3,889 | 3,889 | 3,889 | 3,889 | 3,889 |
| | | | | | | | | | | |
| E | Loss of Source Contingency | (973) | (973) | (973) | (973) | (973) | (973) | (973) | (973) | (973) |
| F | **Resource Need (A+D+E)** | (4,664) | (4,734) | (4,884) | (5,014) | (5,154) | (5,324) | (5,494) | (5,694) | (5,914) |
| | | | | | | | | | | |
| G | J Generation (1) | 8,602 | 8,602 | 8,602 | 8,602 | 8,190 | 8,190 | 8,190 | 8,190 | 8,190 |
| H | J Generation Unavailability (2) | (721) | (721) | (721) | (721) | (721) | (721) | (721) | (721) | (721) |
| I | Unavailability of Non-Firm Gas (4) | (2,057) | (2,057) | (2,057) | (2,057) | (1,646) | (1,646) | (1,646) | (1,646) | (1,646) |
| J | Temperature Based Generation Derates | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| K | Net ICAP External Imports (5) | 140 | 140 | 140 | 140 | 140 | 140 | 140 | 140 | 140 |
| L | **Total Resources Available (G+H+I+J+K)** | 5,963 | 5,963 | 5,963 | 5,963 | 5,964 | 5,964 | 5,964 | 5,964 | 5,964 |
| | | | | | | | | | | |
| M | **Transmission Security Margin (F+L)** | 1,300 | 1,230 | 1,080 | 950 | 810 | 640 | 470 | 270 | 50 |
| N | Higher Demand Impact | (160) | (230) | (310) | (390) | (490) | (650) | (810) | (1,080) | (1,220) |
| O | **Higher Demand Transmission Security Margin (M+N)** | 1,140 | 1,000 | 770 | 560 | 320 | (10) | (340) | (810) | (1,170) |
| P | Noncoincident Peak Demand Impact | (50) | (50) | (50) | (60) | (60) | (60) | (60) | (60) | (60) |
| Q | **Noncoincident Peak Transmission Security Margin (M+P)** | 1,250 | 1,180 | 1,030 | 890 | 750 | 580 | 410 | 210 | (10) |

Notes:

1. Reflects the 2025 Gold Book existing summer capacity plus projected additions and deactivations.
2. Reflects the derates for generating resources. For this evaluation land-based wind generation is assumed to have a capability of 15% of the total nameplate, off-shore wind at 20% of the total nameplate. Solar generation is assumed offline for the winter peak hour. Includes derates for thermal resources based on NERC five-year class average EFORd data published October 2024 (https://www.nerc.com/pa/RAPA/gads/Pages/Reports.aspx). Also includes a reduction of 110 MW based on the impact of Correlated Derates to DMNC on resources impacted by the Modeling Improvements for "Capacity Accreditation project – Correlated Derates" requirements are reflected in the NYISO ICAP manual and the Market Services Tariff Section 5.
3. Limits for 2026 through 2029 are based on the winter peak 2029 representations evaluated in the 2024 RNA. Limits for 2030 through 2034 are based on the winter peak 2034 representations evaluated in the 2024 RNA.
4. Unavailability of non-firm gas is modeled per NYSRC Reliability Rule 154a which became effective May 2024. Includes all gas only units that do not have a firm gas contract.
5. Interchanges are based on ERAG MMWG values and firm transactions. Includes a 175 MW reduction in capacity sales from PJM.

### Figure 46: Winter Peak New York City Transmission Security Margin Calculation – Planned System

| Winter Peak - Expected Weather, Normal Transfer Criteria (MW) | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| **Line** | **Item** | **2026-27** | **2027-28** | **2028-29** | **2029-30** | **2030-31** | **2031-32** | **2032-33** | **2033-34** | **2034-35** |
| A | **Zone J Demand Forecast** | (7,580) | (7,650) | (7,800) | (7,930) | (8,070) | (8,240) | (8,410) | (8,610) | (8,830) |
| | | | | | | | | | | |
| B | I+K to J (3) | 3,900 | 3,900 | 3,900 | 3,900 | 4,900 | 4,900 | 4,900 | 4,900 | 4,900 |
| C | ABC PARs to J | (11) | (11) | (11) | (11) | (11) | (11) | (11) | (11) | (11) |
| D | **Total J AC Import (B+C)** | 3,889 | 3,889 | 3,889 | 3,889 | 4,889 | 4,889 | 4,889 | 4,889 | 4,889 |
| | | | | | | | | | | |
| E | Loss of Source Contingency | (973) | (973) | (973) | (973) | (1,606) | (1,606) | (1,606) | (1,606) | (1,606) |
| F | **Resource Need (A+D+E)** | (4,664) | (4,734) | (4,884) | (5,014) | (4,787) | (4,957) | (5,127) | (5,327) | (5,547) |
| | | | | | | | | | | |
| G | J Generation (1) | 9,433 | 9,433 | 9,433 | 9,433 | 9,021 | 9,021 | 9,021 | 9,021 | 9,021 |
| H | J Generation Unavailability (2) | (1,389) | (1,389) | (1,389) | (1,389) | (1,388) | (1,388) | (1,388) | (1,388) | (1,388) |
| I | Unavailability of Non-Firm Gas (4) | (2,057) | (2,057) | (2,057) | (2,057) | (1,646) | (1,646) | (1,646) | (1,646) | (1,646) |
| J | Temperature Based Generation Derates | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| K | Net ICAP External Imports (5) | 140 | 140 | 140 | 140 | 140 | 140 | 140 | 140 | 140 |
| L | **Total Resources Available (G+H+I+J+K)** | 6,127 | 6,127 | 6,127 | 6,127 | 6,127 | 6,127 | 6,127 | 6,127 | 6,127 |
| | | | | | | | | | | |
| M | **Transmission Security Margin (F+L)** | 1,463 | 1,393 | 1,243 | 1,113 | 1,340 | 1,170 | 1,000 | 800 | 580 |
| N | Higher Demand Impact | (160) | (230) | (310) | (390) | (490) | (650) | (810) | (1,080) | (1,220) |
| O | **Higher Demand Transmission Security Margin (M+N)** | 1,303 | 1,163 | 933 | 723 | 850 | 520 | 190 | (280) | (640) |
| P | Noncoincident Peak Demand Impact | (50) | (50) | (50) | (60) | (60) | (60) | (60) | (60) | (60) |
| Q | **Noncoincident Peak Transmission Security Margin (M+P)** | 1,413 | 1,343 | 1,193 | 1,053 | 1,280 | 1,110 | 940 | 740 | 520 |

Notes:

1. Reflects the 2025 Gold Book existing summer capacity plus projected additions and deactivations.
2. Reflects the derates for generating resources. For this evaluation land-based wind generation is assumed to have a capability of 15% of the total nameplate, off-shore wind at 20% of the total nameplate. Solar generation is assumed offline for the winter peak hour. Includes derates for thermal resources based on NERC five-year class average EFORd data published October 2024 (https://www.nerc.com/pa/RAPA/gads/Pages/Reports.aspx). Also includes a reduction of 110 MW based on the impact of Correlated Derates to DMNC on resources impacted by the Modeling Improvements for "Capacity Accreditation project – Correlated Derates" requirements are reflected in the NYISO ICAP manual and the Market Services Tariff Section 5.
3. Limits for 2026 through 2029 are based on the winter peak 2029 representations evaluated in the 2024 RNA. Limits for 2030 through 2034 are based on the winter peak 2034 representations evaluated in the 2024 RNA.
4. Unavailability of non-firm gas is modeled per NYSRC Reliability Rule 154a which became effective May 2024. Includes all gas only units that do not have a firm gas contract.
5. Interchanges are based on ERAG MMWG values and firm transactions. Includes a 175 MW reduction in capacity sales from PJM.

### Long Island (Zone K)

The Long Island locality comprises Zone K. Within the Long Island Power Authority (LIPA) service territory, the BPTF system (primarily comprised of 138 kV transmission) is designed for N-1-1. To determine the transmission security margin for this area, the most limiting combination of two non-simultaneous contingency events (N-1-1) to the transmission security margin is determined.

For summer 2026 through summer 2029, the most limiting contingency combination is the loss of the Neptune HVDC cable followed by a stuck breaker event at Sprain Brook leading to loss of the Y49 cable. From summer 2030 onward, after the Propel NY project is in service, the limiting contingency combination changes to the loss of the Y50 cable followed by a stuck breaker event at Uniondale. For winter 2026-2027 through winter 2029-2030, the most limiting contingency combination is the loss of the Neptune HVDC cable followed by a stuck breaker event at Sprain Brook. From winter 2030-2031 onward, after the Propel NY project is in service, the limiting contingency combination changes to the loss of the Northport 1 unit followed by loss of a Shore Road-Lake Success 138 kV line (367).

Figures below show the calculation of the summer and winter Long Island transmission security margin. Significant increases in transmission security margins are seen after the Long Island Public Policy transmission project is placed in service.

## Figure 47: Summer Peak Long Island Margin Calculation – Status Quo System

| Summer Peak - Expected Weather, Normal Transfer Criteria (MW) | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| **Line** | **Item** | **2026** | **2027** | **2028** | **2029** | **2030** | **2031** | **2032** | **2033** | **2034** |
| A | **Zone K Demand Forecast** | (4,996) | (5,012) | (5,011) | (5,034) | (5,086) | (5,151) | (5,203) | (5,260) | (5,310) |
| | | | | | | | | | | |
| B | I+J to K (3) | 900 | 900 | 900 | 900 | 900 | 900 | 900 | 900 | 900 |
| C | New England Import (NNC) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| D | **Total K AC Import (B+C)** | 900 | 900 | 900 | 900 | 900 | 900 | 900 | 900 | 900 |
| | | | | | | | | | | |
| E | Loss of Source Contingency | (660) | (660) | (660) | (660) | (660) | (660) | (660) | (660) | (660) |
| F | **Resource Need (A+D+E)** | (4,756) | (4,772) | (4,771) | (4,794) | (4,846) | (4,911) | (4,963) | (5,020) | (5,070) |
| | | | | | | | | | | |
| G | K Generation (1) | 5,001 | 4,901 | 4,901 | 4,901 | 4,901 | 4,856 | 4,856 | 4,856 | 4,856 |
| H | K Generation Unavailability (2) | (832) | (823) | (823) | (824) | (825) | (820) | (821) | (821) | (821) |
| I | Temperature Based Generation Derates | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| J | Net ICAP External Imports (4) | 949 | 660 | 660 | 660 | 660 | 660 | 660 | 660 | 660 |
| K | **Total Resources Available (G+H+I+J)** | 5,117 | 4,738 | 4,737 | 4,736 | 4,736 | 4,695 | 4,695 | 4,695 | 4,694 |
| | | | | | | | | | | |
| L | **Transmission Security Margin (F+K)** | 361 | (34) | (34) | (58) | (110) | (216) | (268) | (325) | (376) |
| M | Higher Demand Impact | (43) | (34) | (30) | (24) | (36) | (47) | (63) | (65) | (110) |
| N | **Higher Demand Transmission Security Margin (L+M)** | 318 | (68) | (64) | (82) | (146) | (263) | (331) | (390) | (486) |
| O | Noncoincident Peak Demand Impact | (76) | (77) | (77) | (78) | (79) | (80) | (81) | (82) | (83) |
| P | **Noncoincident Peak Transmission Security Margin (L+O)** | 285 | (111) | (111) | (136) | (189) | (296) | (349) | (407) | (459) |

Notes:

1. Reflects the 2025 Gold Book existing summer capacity plus projected additions and deactivations.
2. Reflects the derates for generating resources. For this evaluation land-based wind generation is assumed to have a capability of 5% of the total nameplate, off-shore wind at 10% of the total nameplate, solar generation is based on the ratio of solar PV nameplate capacity (2025 Gold Book Table I-9a) and solar PV peak reductions (2025 Gold Book Table I-9c). Derates for run-of-river hydro are included. Includes derates for thermal resources based on NERC five-year class average EFORd data published October 2023 https://www.nerc.com/pa/RAPA/gads/Pages/Reports.aspx). Also includes a reduction of 200 MW based on the impact of Correlated Derates to DMNC on resources impacted by the Modeling Improvements for "Capacity Accreditation project – Correlated Derates" requirements are reflected in the NYISO ICAP manual and the Market Services Tariff Section 5.
3. Limits for 2026 through 2029 are based on the 2024 LIPA Summer Operating Study. Limits for 2030 through 2034 are based on the 2034-2035W winter peak representations evaluated in the 2024RNA.
4. Interchanges are based on ERAG MMWG values and firm transactions. Includes a 175 MW reduction in capacity sales from PJM. Includes external imports from the Cross-Sound Cable in accordance with planned imports through early 2027, but starting in summer 2027 this import is assumed at 0 MW.

### Figure 48: Summer Peak Long Island Margin Calculation – Planned System

| Summer Peak - Expected Weather, Normal Transfer Criteria (MW) | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| **Line** | **Item** | **2026** | **2027** | **2028** | **2029** | **2030** | **2031** | **2032** | **2033** | **2034** |
| A | **Zone K Demand Forecast** | (4,996) | (5,012) | (5,011) | (5,034) | (5,086) | (5,151) | (5,203) | (5,260) | (5,310) |
| | | | | | | | | | | |
| B | I+J to K (3) | 900 | 900 | 900 | 900 | 2,200 | 2,200 | 2,200 | 2,200 | 2,200 |
| C | New England Import (NNC) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| D | **Total K AC Import (B+C)** | 900 | 900 | 900 | 900 | 2,200 | 2,200 | 2,200 | 2,200 | 2,200 |
| | | | | | | | | | | |
| E | Loss of Source Contingency | (660) | (660) | (660) | (660) | 0 | 0 | 0 | 0 | 0 |
| F | **Resource Need (A+D+E)** | (4,756) | (4,772) | (4,771) | (4,794) | (2,886) | (2,951) | (3,003) | (3,060) | (3,110) |
| | | | | | | | | | | |
| G | K Generation (1) | 5,001 | 5,001 | 5,925 | 5,925 | 5,925 | 5,880 | 5,880 | 5,880 | 5,880 |
| H | K Generation Unavailability (2) | (832) | (833) | (1,665) | (1,666) | (1,666) | (1,662) | (1,662) | (1,662) | (1,663) |
| I | Temperature Based Generation Derates | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| J | Net ICAP External Imports (4) | 949 | 660 | 660 | 660 | 660 | 660 | 660 | 660 | 660 |
| K | **Total Resources Available (G+H+I+J)** | 5,117 | 4,828 | 4,920 | 4,919 | 4,918 | 4,878 | 4,877 | 4,877 | 4,877 |
| | | | | | | | | | | |
| L | **Transmission Security Margin (F+K)** | 361 | 56 | 149 | 125 | 2,032 | 1,927 | 1,874 | 1,817 | 1,767 |
| M | Higher Demand Impact | (43) | (34) | (30) | (24) | (36) | (47) | (63) | (65) | (110) |
| N | **Higher Demand Transmission Security Margin (L+M)** | 318 | 22 | 119 | 101 | 1,996 | 1,880 | 1,811 | 1,752 | 1,657 |
| O | Noncoincident Peak Demand Impact | (76) | (77) | (77) | (78) | (79) | (80) | (81) | (82) | (83) |
| P | **Noncoincident Peak Transmission Security Margin (L+O)** | 285 | (21) | 72 | 47 | 1,953 | 1,847 | 1,793 | 1,735 | 1,684 |

Notes:

1. Reflects the 2025 Gold Book existing summer capacity plus projected additions and deactivations.
2. Reflects the derates for generating resources. For this evaluation land-based wind generation is assumed to have a capability of 5% of the total nameplate, off-shore wind at 10% of the total nameplate, solar generation is based on the ratio of solar PV nameplate capacity (2025 Gold Book Table I-9a) and solar PV peak reductions (2025 Gold Book Table I-9c). Derates for run-of-river hydro are included. Includes derates for thermal resources based on NERC five-year class average EFORd data published October 2023 https://www.nerc.com/pa/RAPA/gads/Pages/Reports.aspx). Also includes a reduction of 200 MW based on the impact of Correlated Derates to DMNC on resources impacted by the Modeling Improvements for "Capacity Accreditation project – Correlated Derates" requirements are reflected in the NYISO ICAP manual and the Market Services Tariff Section 5.
3. Limits for 2026 through 2029 are based on the 2024 LIPA Summer Operating Study. Limits for 2030 through 2034 are based on the 2034-2035W winter peak representations evaluated in the 2024RNA.
4. Interchanges are based on ERAG MMWG values and firm transactions. Includes a 175 MW reduction in capacity sales from PJM. Includes external imports from the Cross-Sound Cable in accordance with planned imports through early 2027, but starting in summer 2027 this import is assumed at 0 MW.

## Figure 49: Winter Peak Long Island Margin Calculation – Status Quo System

| Winter Peak - Expected Weather, Normal Transfer Criteria (MW) | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| **Line** | **Item** | **2026-27** | **2027-28** | **2028-29** | **2029-30** | **2030-31** | **2031-32** | **2032-33** | **2033-34** | **2034-35** |
| A | **Zone K Demand Forecast** | (3,276) | (3,335) | (3,443) | (3,585) | (3,716) | (3,860) | (3,995) | (4,114) | (4,221) |
| | | | | | | | | | | |
| B | I+J to K (3), (4) | 900 | 900 | 900 | 900 | 900 | 900 | 900 | 900 | 900 |
| C | New England Import (NNC) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| D | **Total K AC Import (B+C)** | 900 | 900 | 900 | 900 | 900 | 900 | 900 | 900 | 900 |
| | | | | | | | | | | |
| E | Loss of Source Contingency | (660) | (660) | (660) | (660) | (660) | (660) | (660) | (660) | (660) |
| F | **Resource Need (A+D+E)** | (3,036) | (3,095) | (3,203) | (3,345) | (3,476) | (3,620) | (3,755) | (3,874) | (3,981) |
| | | | | | | | | | | |
| G | K Generation (1) | 5,437 | 5,320 | 5,320 | 5,320 | 5,274 | 5,274 | 5,274 | 5,274 | 5,274 |
| H | K Generation Unavailability (2) | (852) | (840) | (840) | (840) | (839) | (839) | (839) | (839) | (839) |
| I | Shortage of Gas Fuel Supply (5) | (318) | (318) | (318) | (318) | (272) | (272) | (272) | (272) | (272) |
| J | Temperature Based Generation Derates | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| K | Net ICAP External Imports (6) | 949 | 660 | 660 | 660 | 660 | 660 | 660 | 660 | 660 |
| L | **Total Resources Available (G+H+I+J+K)** | 5,216 | 4,822 | 4,822 | 4,822 | 4,823 | 4,823 | 4,823 | 4,823 | 4,823 |
| | | | | | | | | | | |
| M | **Transmission Security Margin (F+L)** | 2,180 | 1,727 | 1,619 | 1,477 | 1,347 | 1,203 | 1,068 | 949 | 842 |
| N | Higher Demand Impact | (20) | (15) | (29) | (88) | (155) | (246) | (348) | (529) | (601) |
| O | **Higher Demand Transmission Security Margin (M+N)** | 2,160 | 1,712 | 1,590 | 1,389 | 1,192 | 957 | 720 | 420 | 241 |
| P | Noncoincident Peak Demand Impact | (13) | (13) | (14) | (15) | (15) | (16) | (16) | (17) | (17) |
| Q | **Noncoincident Peak Transmission Security Margin (M+P)** | 2,167 | 1,714 | 1,605 | 1,462 | 1,332 | 1,187 | 1,052 | 932 | 825 |

Notes:

1. Reflects the 2025 Gold Book existing winter capacity plus projected additions and deactivations.
2. Reflects the derates for generating resources. For this evaluation land-based wind generation is assumed to have a capability of 15% of the total nameplate, off-shore wind at 20% of the total nameplate. For winter the expected solar PV output at peak is 0 MW. Derates for run-of-river hydro are included. Includes derates for thermal resources based on NERC five-year class average EFORd data published October 2024 (https://www.nerc.com/pa/RAPA/gads/Pages/Reports.aspx). Also includes a reduction of 200 MW based on the impact of Correlated Derates to DMNC on resources impacted by the Modeling Improvements for "Capacity Accreditation project – Correlated Derates" requirements are reflected in the NYISO ICAP manual and the Market Services Tariff Section 5.
3. Limits for 2026 through 2029 are based on the 2024 LIPA Summer Operating Study. Limits for 2030 through 2034 are based on the 2034-2035W winter peak representations evaluated in the 2024RNA.
4. As a conservative winter peak assumption these limits utilize the summer values through 2029-2030W.
5. Includes all gas only units that do not have a firm gas contract.
6. Interchanges are based on ERAG MMWG values and firm transactions. Includes a 175 MW reduction in capacity sales from PJM. Includes external imports from the Cross-Sound Cable in accordance with planned imports through early 2027, but starting in summer 2027 this import is assumed at 0 MW.

## Figure 50: Winter Peak Long Island Margin Calculation – Planned System

| Winter Peak - Baseline Weather, Normal Transfer Criteria (MW) | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| **Line** | **Item** | **2026-27** | **2027-28** | **2028-29** | **2029-30** | **2030-31** | **2031-32** | **2032-33** | **2033-34** | **2034-35** |
| A | **Zone K Demand Forecast** | (3,276) | (3,335) | (3,443) | (3,585) | (3,716) | (3,860) | (3,995) | (4,114) | (4,221) |
| | | | | | | | | | | |
| B | I+J to K (3), (4) | 900 | 900 | 900 | 900 | 2,500 | 2,500 | 2,500 | 2,500 | 2,500 |
| C | New England Import (NNC) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| D | **Total K AC Import (B+C)** | 900 | 900 | 900 | 900 | 2,500 | 2,500 | 2,500 | 2,500 | 2,500 |
| | | | | | | | | | | |
| E | Loss of Source Contingency | (660) | (660) | (660) | (660) | (399) | (399) | (399) | (399) | (399) |
| F | **Resource Need (A+D+E)** | (3,036) | (3,095) | (3,203) | (3,345) | (1,615) | (1,759) | (1,894) | (2,013) | (2,120) |
| | | | | | | | | | | |
| G | K Generation (1) | 5,437 | 6,361 | 6,361 | 6,361 | 6,315 | 6,315 | 6,315 | 6,315 | 6,315 |
| H | K Generation Unavailability (2) | (852) | (1,591) | (1,591) | (1,591) | (1,591) | (1,591) | (1,591) | (1,591) | (1,591) |
| I | Shortage of Gas Fuel Supply (5) | (318) | (318) | (318) | (318) | (272) | (272) | (272) | (272) | (272) |
| J | Temperature Based Generation Derates | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| K | Net ICAP External Imports (6) | 949 | 660 | 660 | 660 | 660 | 660 | 660 | 660 | 660 |
| L | **Total Resources Available (G+H+I+J+K)** | 5,216 | 5,112 | 5,112 | 5,112 | 5,113 | 5,113 | 5,113 | 5,113 | 5,113 |
| | | | | | | | | | | |
| M | **Transmission Security Margin (F+L)** | 2,180 | 2,017 | 1,909 | 1,767 | 3,498 | 3,354 | 3,219 | 3,100 | 2,993 |
| N | Higher Demand Impact | (20) | (15) | (29) | (88) | (155) | (246) | (348) | (529) | (601) |
| O | **Higher Demand Transmission Security Margin (M+N)** | 2,160 | 2,002 | 1,880 | 1,679 | 3,343 | 3,108 | 2,871 | 2,571 | 2,392 |
| P | Noncoincident Peak Demand Impact | (13) | (13) | (14) | (15) | (15) | (16) | (16) | (17) | (17) |
| Q | **Noncoincident Peak Transmission Security Margin (M+P)** | 2,167 | 2,004 | 1,895 | 1,752 | 3,483 | 3,338 | 3,203 | 3,083 | 2,976 |

Notes:

1. Reflects the 2025 Gold Book existing winter capacity plus projected additions and deactivations.
2. Reflects the derates for generating resources. For this evaluation land-based wind generation is assumed to have a capability of 15% of the total nameplate, off-shore wind at 20% of the total nameplate. For winter the expected solar PV output at peak is 0 MW. Derates for run-of-river hydro are included. Includes derates for thermal resources based on NERC five-year class average EFORd data published October 2024 (https://www.nerc.com/pa/RAPA/gads/Pages/Reports.aspx). Also includes a reduction of 200 MW based on the impact of Correlated Derates to DMNC on resources impacted by the Modeling Improvements for "Capacity Accreditation project – Correlated Derates" requirements are reflected in the NYISO ICAP manual and the Market Services Tariff Section 5.
3. Limits for 2026 through 2029 are based on the 2024 LIPA Summer Operating Study. Limits for 2030 through 2034 are based on the 2034-2035W winter peak representations evaluated in the 2024RNA.
4. As a conservative winter peak assumption these limits utilize the summer values through 2029-2030W.
5. Includes all gas only units that do not have a firm gas contract.
6. Interchanges are based on ERAG MMWG values and firm transactions. Includes external imports from the Cross-Sound Cable in accordance with planned imports through early 2027, but starting in summer 2027 this import is assumed at 0 MW.

## Appendix F – Additional Outage Impacts to Margins

The figures in this section show the impact of additional generator and plant outages, or Additional Outage Impacts (AOI), on the statewide system margin and transmission security margins for each locality. The impact of the outages is shown relative to the base margins considering the higher demand forecast with flexible large loads modeled offline.

- Figure 51: AOI - Statewide System Margin
- Figure 52: AOI - Lower Hudson Valley Transmission Security Margin
- Figure 53: AOI - New York City Transmission Security Margin
- Figure 54: AOI - Long Island Transmission Security Margin

**Figure 51: AOI - Statewide System Margin**

| Statewide System Margin | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Year | | | | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 |
| Statewide System Margin Summer Peak - Baseline Expected Summer Weather, Normal Transfer Criteria (MW) (1) | | | | 312 | (486) | (938) | (1,552) | (2,132) | (3,029) | (3,518) | (4,032) | (4,685) |
| Unit Name | Summer DMNC (MW) | NERC 5-Year Class Average De-Rate (MW) | Summer De-Rated Capability (MW) | Transmission Security Margin Considering Impact of Generator Outage (Retire, Mothball, IIFO) | | | | | | | | |
| Jamestown 5, 6 & 7 | 74.7 | (7.90) | 66.80 | 246 | (552) | (1,005) | (1,619) | (2,199) | (3,096) | (3,584) | (4,098) | (4,752) |
| Jamestown 5 | 19.0 | (2.06) | 16.94 | 296 | (503) | (955) | (1,569) | (2,149) | (3,046) | (3,535) | (4,049) | (4,702) |
| Jamestown 6 | 16.5 | (1.79) | 14.71 | 298 | (500) | (953) | (1,567) | (2,146) | (3,044) | (3,532) | (4,046) | (4,700) |
| Jamestown 7 | 39.2 | (4.05) | 35.15 | 277 | (521) | (974) | (1,587) | (2,167) | (3,064) | (3,553) | (4,067) | (4,720) |
| Indeck-Yerkes | 43.1 | (2.03) | 41.07 | 271 | (527) | (980) | (1,593) | (2,173) | (3,070) | (3,559) | (4,073) | (4,726) |
| Indeck-Olean | 79.0 | (3.72) | 75.28 | 237 | (561) | (1,014) | (1,627) | (2,207) | (3,104) | (3,593) | (4,107) | (4,761) |
| American Ref-Fuel 1 & 2 | 37.6 | (4.08) | 33.52 | 279 | (519) | (972) | (1,586) | (2,165) | (3,062) | (3,551) | (4,065) | (4,719) |
| American Ref-Fuel 1 | 18.8 | (2.04) | 16.76 | 296 | (502) | (955) | (1,569) | (2,149) | (3,046) | (3,534) | (4,048) | (4,702) |
| American Ref-Fuel 2 | 18.8 | (2.04) | 16.76 | 296 | (502) | (955) | (1,569) | (2,149) | (3,046) | (3,534) | (4,048) | (4,702) |
| Fortistar - N.Tonawanda (BTM:NG) | 46.5 | (2.19) | 44.31 | 268 | (530) | (983) | (1,596) | (2,176) | (3,073) | (3,562) | (4,076) | (4,730) |
| Model City Energy | 5.6 | (0.74) | 4.86 | 308 | (490) | (943) | (1,557) | (2,137) | (3,034) | (3,522) | (4,036) | (4,690) |
| Modern LF | 6.4 | (0.84) | 5.56 | 307 | (491) | (944) | (1,558) | (2,137) | (3,034) | (3,523) | (4,037) | (4,691) |
| Chaffee | 6.4 | (0.84) | 5.56 | 307 | (491) | (944) | (1,558) | (2,137) | (3,034) | (3,523) | (4,037) | (4,691) |
| Chautauqua LFGE | 0.0 | 0.00 | 0.00 | 312 | (486) | (938) | (1,552) | (2,132) | (3,029) | (3,518) | (4,032) | (4,685) |
| Lockport CC1, CC2, and CC3 | 210.0 | (9.89) | 200.11 | 112 | (686) | (1,139) | (1,752) | (2,332) | (3,229) | (3,718) | (4,232) | (4,885) |
| Lockport CC1 | 70.0 | (3.30) | 66.70 | 246 | (552) | (1,005) | (1,619) | (2,198) | (3,096) | (3,584) | (4,098) | (4,752) |
| Lockport CC2 | 70.0 | (3.30) | 66.70 | 246 | (552) | (1,005) | (1,619) | (2,198) | (3,096) | (3,584) | (4,098) | (4,752) |
| Lockport CC3 | 70.0 | (3.30) | 66.70 | 246 | (552) | (1,005) | (1,619) | (2,198) | (3,096) | (3,584) | (4,098) | (4,752) |

| Statewide System Margin | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | Year | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 |
| Statewide System Margin Summer Peak - Baseline Expected Summer Weather, Normal Transfer Criteria (MW) (1) | | | | 312 | (486) | (938) | (1,552) | (2,132) | (3,029) | (3,518) | (4,032) | (4,685) |
| Unit Name | Summer DMNC (MW) | NERC 5-Year Class Average De-Rate (MW) | Summer De-Rated Capability (MW) | Transmission Security Margin Considering Impact of Generator Outage (Retire, Mothball, IIFO) | | | | | | | | |
| Allegany | 62.7 | (2.95) | 59.75 | 253 | (545) | (998) | (1,612) | (2,192) | (3,089) | (3,577) | (4,091) | (4,745) |
| R. E. Ginna | 578.8 | (11.98) | 566.82 | (254) | (1,052) | (1,505) | (2,119) | (2,699) | (3,596) | (4,084) | (4,598) | (5,252) |
| Batavia | 47.5 | (2.24) | 45.26 | 267 | (531) | (984) | (1,597) | (2,177) | (3,074) | (3,563) | (4,077) | (4,731) |
| Nine Mile Point 2[2] | 1,283.4 | (23.10) | 1,260.30 | (659) | (1,457) | (1,910) | (2,524) | (3,104) | (4,001) | (4,489) | (5,003) | (5,657) |
| Mill Seat | 6.4 | (0.84) | 5.56 | 307 | (491) | (944) | (1,558) | (2,137) | (3,034) | (3,523) | (4,037) | (4,691) |
| Hyland LFGE | 4.8 | (0.63) | 4.17 | 308 | (490) | (943) | (1,556) | (2,136) | (3,033) | (3,522) | (4,036) | (4,689) |
| Synergy Biogas | 0.0 | 0.00 | 0.00 | 312 | (486) | (938) | (1,552) | (2,132) | (3,029) | (3,518) | (4,032) | (4,685) |
| Red Rochester (BTM:NG) | 16.5 | (1.79) | 14.71 | 298 | (500) | (953) | (1,567) | (2,146) | (3,044) | (3,532) | (4,046) | (4,700) |
| James A. FitzPatrick | 844.0 | (15.19) | 828.81 | (516) | (1,314) | (1,767) | (2,381) | (2,961) | (3,858) | (4,346) | (4,860) | (5,514) |
| Oswego 6 | 791.7 | (85.90) | 705.80 | (393) | (1,191) | (1,644) | (2,258) | (2,838) | (3,735) | (4,223) | (4,737) | (5,391) |
| Oswego 5 | 820.5 | (89.02) | 731.48 | (419) | (1,217) | (1,670) | (2,284) | (2,863) | (3,760) | (4,249) | (4,763) | (5,417) |
| Nine Mile Point 1 | 619.7 | (11.15) | 608.55 | (296) | (1,094) | (1,547) | (2,161) | (2,740) | (3,637) | (4,126) | (4,640) | (5,294) |
| Independence GS1, GS2, GS3, & GS4 | 996.4 | (46.93) | 949.47 | (637) | (1,435) | (1,888) | (2,502) | (3,081) | (3,978) | (4,467) | (4,981) | (5,635) |
| Independence GS1 | 249.1 | (11.73) | 237.37 | 75 | (723) | (1,176) | (1,789) | (2,369) | (3,266) | (3,755) | (4,269) | (4,923) |
| Independence GS2 | 249.1 | (11.73) | 237.37 | 75 | (723) | (1,176) | (1,789) | (2,369) | (3,266) | (3,755) | (4,269) | (4,923) |
| Independence GS3 | 249.1 | (11.73) | 237.37 | 75 | (723) | (1,176) | (1,789) | (2,369) | (3,266) | (3,755) | (4,269) | (4,923) |
| Independence GS4 | 249.1 | (11.73) | 237.37 | 75 | (723) | (1,176) | (1,789) | (2,369) | (3,266) | (3,755) | (4,269) | (4,923) |
| Syracuse | 86.2 | (4.06) | 82.14 | 230 | (568) | (1,021) | (1,634) | (2,214) | (3,111) | (3,600) | (4,114) | (4,767) |

| Statewide System Margin | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Year | | | | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 |
| Statewide System Margin Summer Peak - Baseline Expected Summer Weather, Normal Transfer Criteria (MW) (1) | | | | 312 | (486) | (938) | (1,552) | (2,132) | (3,029) | (3,518) | (4,032) | (4,685) |
| Unit Name | Summer DMNC (MW) | NERC 5-Year Class Average De-Rate (MW) | Summer De-Rated Capability (MW) | Transmission Security Margin Considering Impact of Generator Outage (Retire, Mothball, IIFO) | | | | | | | | |
| Carr St.-E. Syr | 89.6 | (4.22) | 85.38 | 227 | (571) | (1,024) | (1,637) | (2,217) | (3,114) | (3,603) | (4,117) | (4,771) |
| Indeck-Oswego | 51.9 | (2.44) | 49.46 | 263 | (535) | (988) | (1,602) | (2,181) | (3,078) | (3,567) | (4,081) | (4,735) |
| Indeck-Silver Springs | 52.7 | (2.48) | 50.22 | 262 | (536) | (989) | (1,602) | (2,182) | (3,079) | (3,568) | (4,082) | (4,735) |
| Greenidge 4 (BTM:NG) | 29.8 | (3.23) | 26.57 | 286 | (1,047) | 169 | (36) | (240) | (494) | (834) | (1,328) | (1,823) |
| Ontario LFGE | 11.2 | (1.48) | 9.72 | 303 | (495) | (948) | (1,562) | (2,141) | (3,039) | (3,527) | (4,041) | (4,695) |
| High Acres | 9.6 | (1.27) | 8.33 | 304 | (494) | (947) | (1,560) | (2,140) | (3,037) | (3,526) | (4,040) | (4,694) |
| Seneca Energy 1 & 2 | 17.6 | (2.32) | 15.28 | 297 | (501) | (954) | (1,567) | (2,147) | (3,044) | (3,533) | (4,047) | (4,701) |
| Seneca Energy 1 | 8.8 | (1.16) | 7.64 | 305 | (493) | (946) | (1,560) | (2,139) | (3,037) | (3,525) | (4,039) | (4,693) |
| Seneca Energy 2 | 8.8 | (1.16) | 7.64 | 305 | (493) | (946) | (1,560) | (2,139) | (3,037) | (3,525) | (4,039) | (4,693) |
| Broome LFGE | 2.4 | (0.32) | 2.08 | 310 | (488) | (941) | (1,554) | (2,134) | (3,031) | (3,520) | (4,034) | (4,687) |
| Massena | 79.5 | (3.74) | 75.76 | 237 | (561) | (1,014) | (1,628) | (2,208) | (3,105) | (3,593) | (4,107) | (4,761) |
| Clinton LFGE | 6.4 | (0.84) | 5.56 | 307 | (491) | (944) | (1,558) | (2,137) | (3,034) | (3,523) | (4,037) | (4,691) |
| Saranac Energy CC1 & CC2 | 239.4 | (11.28) | 228.12 | 84 | (714) | (1,167) | (1,780) | (2,360) | (3,257) | (3,746) | (4,260) | (4,913) |
| Saranac Energy CC1 | 122.1 | (5.75) | 116.35 | 196 | (602) | (1,055) | (1,668) | (2,248) | (3,145) | (3,634) | (4,148) | (4,802) |
| Saranac Energy CC2 | 117.3 | (5.52) | 111.78 | 201 | (597) | (1,050) | (1,664) | (2,244) | (3,141) | (3,629) | (4,143) | (4,797) |
| Sterling | 48.4 | (2.28) | 46.12 | 266 | (532) | (985) | (1,598) | (2,178) | (3,075) | (3,564) | (4,078) | (4,731) |
| Carthage Energy | 52.8 | (2.49) | 50.31 | 262 | (536) | (989) | (1,602) | (2,182) | (3,079) | (3,568) | (4,082) | (4,736) |
| Beaver Falls | 79.7 | (3.75) | 75.95 | 237 | (562) | (1,014) | (1,628) | (2,208) | (3,105) | (3,594) | (4,108) | (4,761) |

| Statewide System Margin | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Year | | | | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 |
| Statewide System Margin Summer Peak - Baseline Expected Summer Weather, Normal Transfer Criteria (MW) (1) | | | | 312 | (486) | (938) | (1,552) | (2,132) | (3,029) | (3,518) | (4,032) | (4,685) |
| Unit Name | Summer DMNC (MW) | NERC 5-Year Class Average De-Rate (MW) | Summer De-Rated Capability (MW) | Transmission Security Margin Considering Impact of Generator Outage (Retire, Mothball, IIFO) | | | | | | | | |
| Broome 2 LFGE | 2.1 | (0.28) | 1.82 | 311 | (487) | (940) | (1,554) | (2,134) | (3,031) | (3,519) | (4,033) | (4,687) |
| DANC LFGE | 6.4 | (0.84) | 5.56 | 307 | (491) | (944) | (1,558) | (2,137) | (3,034) | (3,523) | (4,037) | (4,691) |
| Oneida-Herkimer LFGE | 3.2 | (0.42) | 2.78 | 310 | (488) | (941) | (1,555) | (2,135) | (3,032) | (3,520) | (4,034) | (4,688) |
| Athens 1, 2, and 3 | 947.7 | (44.64) | 903.06 | (591) | (1,389) | (1,842) | (2,455) | (3,035) | (3,932) | (4,421) | (4,935) | (5,588) |
| Athens 1 | 329.4 | (15.51) | 313.89 | (1) | (799) | (1,252) | (1,866) | (2,446) | (3,343) | (3,831) | (4,345) | (4,999) |
| Athens 2 | 333.3 | (15.70) | 317.60 | (5) | (803) | (1,256) | (1,870) | (2,449) | (3,347) | (3,835) | (4,349) | (5,003) |
| Athens 3 | 285.0 | (13.42) | 271.58 | 41 | (757) | (1,210) | (1,824) | (2,403) | (3,301) | (3,789) | (4,303) | (4,957) |
| Rensselaer | 76.8 | (3.62) | 73.18 | 239 | (559) | (1,012) | (1,625) | (2,205) | (3,102) | (3,591) | (4,105) | (4,758) |
| Wheelabrator Hudson Falls | 10.4 | (1.13) | 9.27 | 303 | (495) | (948) | (1,561) | (2,141) | (3,038) | (3,527) | (4,041) | (4,695) |
| Selkirk I & II | 353.0 | (16.63) | 336.37 | (24) | (822) | (1,275) | (1,888) | (2,468) | (3,365) | (3,854) | (4,368) | (5,022) |
| Selkirk-I | 76.4 | (3.60) | 72.80 | 240 | (558) | (1,011) | (1,625) | (2,205) | (3,102) | (3,590) | (4,104) | (4,758) |
| Selkirk-II | 276.6 | (13.03) | 263.57 | 49 | (749) | (1,202) | (1,816) | (2,395) | (3,293) | (3,781) | (4,295) | (4,949) |
| Indeck-Corinth | 128.5 | (6.05) | 122.45 | 190 | (608) | (1,061) | (1,675) | (2,254) | (3,151) | (3,640) | (4,154) | (4,808) |
| Castleton Energy Center | 67.0 | (3.16) | 63.84 | 249 | (549) | (1,002) | (1,616) | (2,196) | (3,093) | (3,581) | (4,095) | (4,749) |
| Bethlehem GS1, GS2, GS3 | 817.2 | (38.49) | 778.71 | (466) | (1,264) | (1,717) | (2,331) | (2,910) | (3,808) | (4,296) | (4,810) | (5,464) |
| Bethlehem GS1 | 272.4 | (12.83) | 259.57 | 53 | (745) | (1,198) | (1,812) | (2,391) | (3,288) | (3,777) | (4,291) | (4,945) |
| Bethlehem GS2 | 272.4 | (12.83) | 259.57 | 53 | (745) | (1,198) | (1,812) | (2,391) | (3,288) | (3,777) | (4,291) | (4,945) |
| Bethlehem GS3 | 272.4 | (12.83) | 259.57 | 53 | (745) | (1,198) | (1,812) | (2,391) | (3,288) | (3,777) | (4,291) | (4,945) |
| Colonie LFGTE | 6.4 | (0.84) | 5.56 | 307 | (491) | (944) | (1,558) | (2,137) | (3,034) | (3,523) | (4,037) | (4,691) |
| Albany LFGE | 5.6 | (0.74) | 4.86 | 308 | (490) | (943) | (1,557) | (2,137) | (3,034) | (3,522) | (4,036) | (4,690) |

| Statewide System Margin | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | Year | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 |
| Statewide System Margin Summer Peak - Baseline Expected Summer Weather, Normal Transfer Criteria (MW) (1) | | | | 312 | (486) | (938) | (1,552) | (2,132) | (3,029) | (3,518) | (4,032) | (4,685) |
| Unit Name | Summer DMNC (MW) | NERC 5-Year Class Average De-Rate (MW) | Summer De-Rated Capability (MW) | Transmission Security Margin Considering Impact of Generator Outage (Retire, Mothball, IIFO) | | | | | | | | |
| Fulton LFGE | 3.2 | (0.42) | 2.78 | 310 | (488) | (941) | (1,555) | (2,135) | (3,032) | (3,520) | (4,034) | (4,688) |
| Empire CC1 & CC2 | 591.6 | (27.86) | 563.74 | (251) | (1,049) | (1,502) | (2,116) | (2,696) | (3,593) | (4,081) | (4,595) | (5,249) |
| Empire CC1 | 295.8 | (13.93) | 281.87 | 31 | (767) | (1,220) | (1,834) | (2,414) | (3,311) | (3,799) | (4,313) | (4,967) |
| Empire CC2 | 295.8 | (13.93) | 281.87 | 31 | (767) | (1,220) | (1,834) | (2,414) | (3,311) | (3,799) | (4,313) | (4,967) |
| Bowline 1 & 2 | 1,136.3 | (123.29) | 1,013.01 | (701) | (1,499) | (1,951) | (2,565) | (3,145) | (4,042) | (4,531) | (5,045) | (5,698) |
| Bowline 1 | 565.1 | (61.31) | 503.79 | (191) | (989) | (1,442) | (2,056) | (2,636) | (3,533) | (4,021) | (4,535) | (5,189) |
| Bowline 2 | 571.2 | (61.98) | 509.22 | (197) | (995) | (1,448) | (2,061) | (2,641) | (3,538) | (4,027) | (4,541) | (5,194) |
| Danskammer 1, 2, 3, & 4 | 498.2 | (54.05) | 444.15 | (132) | (930) | (1,383) | (1,996) | (2,576) | (3,473) | (3,962) | (4,476) | (5,129) |
| Danskammer 1 | 68.8 | (7.46) | 61.34 | 251 | (547) | (1,000) | (1,613) | (2,193) | (3,090) | (3,579) | (4,093) | (4,747) |
| Danskammer 2 | 64.9 | (7.04) | 57.86 | 255 | (543) | (996) | (1,610) | (2,190) | (3,087) | (3,575) | (4,089) | (4,743) |
| Danskammer 3 | 140.2 | (15.21) | 124.99 | 188 | (611) | (1,063) | (1,677) | (2,257) | (3,154) | (3,643) | (4,157) | (4,810) |
| Danskammer 4 | 224.3 | (24.34) | 199.96 | 113 | (686) | (1,138) | (1,752) | (2,332) | (3,229) | (3,718) | (4,232) | (4,885) |
| Roseton 1 & 2 | 1,224.1 | (132.81) | 1,091.29 | (779) | (1,577) | (2,030) | (2,643) | (3,223) | (4,120) | (4,609) | (5,123) | (5,777) |
| Roseton 1 | 616.8 | (66.92) | 549.88 | (237) | (1,035) | (1,488) | (2,102) | (2,682) | (3,579) | (4,067) | (4,581) | (5,235) |
| Roseton 2 | 607.3 | (65.89) | 541.41 | (229) | (1,027) | (1,480) | (2,094) | (2,673) | (3,570) | (4,059) | (4,573) | (5,227) |
| Hillburn GT | 34.7 | (3.14) | 31.56 | 281 | (517) | (970) | (1,584) | (2,163) | (3,060) | (3,549) | (4,063) | (4,717) |
| Shoemaker GT | 32.3 | (2.92) | 29.38 | 283 | (515) | (968) | (1,581) | (2,161) | (3,058) | (3,547) | (4,061) | (4,715) |
| DCRRA | 6.3 | (0.68) | 5.62 | 307 | (491) | (944) | (1,558) | (2,137) | (3,035) | (3,523) | (4,037) | (4,691) |
| CPV Valley CC1 & CC2 | 649.8 | (30.61) | 619.19 | (307) | (1,105) | (1,558) | (2,171) | (2,751) | (3,648) | (4,137) | (4,651) | (5,304) |
| CPV Valley CC1 | 320.4 | (15.09) | 305.31 | 7 | (791) | (1,244) | (1,857) | (2,437) | (3,334) | (3,823) | (4,337) | (4,991) |

| Statewide System Margin | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Year | | | | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 |
| Statewide System Margin Summer Peak - Baseline Expected Summer Weather, Normal Transfer Criteria (MW) (1) | | | | 312 | (486) | (938) | (1,552) | (2,132) | (3,029) | (3,518) | (4,032) | (4,685) |
| Unit Name | Summer DMNC (MW) | NERC 5-Year Class Average De-Rate (MW) | Summer De-Rated Capability (MW) | Transmission Security Margin Considering Impact of Generator Outage (Retire, Mothball, IIFO) | | | | | | | | |
| CPV Valley CC2 | 329.4 | (15.51) | 313.89 | (1) | (799) | (1,252) | (1,866) | (2,446) | (3,343) | (3,831) | (4,345) | (4,999) |
| Cricket Valley CC1, CC2, & CC3 | 1,021.6 | (48.12) | 973.48 | (661) | (1,459) | (1,912) | (2,526) | (3,105) | (4,002) | (4,491) | (5,005) | (5,659) |
| Cricket Valley CC1 | 349.7 | (16.47) | 333.23 | (21) | (819) | (1,272) | (1,885) | (2,465) | (3,362) | (3,851) | (4,365) | (5,018) |
| Cricket Valley CC2 | 345.5 | (16.27) | 329.23 | (17) | (815) | (1,268) | (1,881) | (2,461) | (3,358) | (3,847) | (4,361) | (5,014) |
| Cricket Valley CC3 | 326.4 | (15.37) | 311.03 | 1 | (797) | (1,249) | (1,863) | (2,443) | (3,340) | (3,829) | (4,343) | (4,996) |
| Wheelabrator Westchester | 53.5 | (5.80) | 47.70 | 265 | (533) | (986) | (1,600) | (2,179) | (3,077) | (3,565) | (4,079) | (4,733) |
| Arthur Kill ST 2 & 3 | 883.6 | (95.87) | 787.73 | (475) | (1,273) | (1,726) | (2,340) | (2,919) | (3,817) | (4,305) | (4,819) | (5,473) |
| Arthur Kill ST 2 | 363.2 | (39.41) | 323.79 | (11) | (809) | (1,262) | (1,876) | (2,456) | (3,353) | (3,841) | (4,355) | (5,009) |
| Arthur Kill ST 3 | 520.4 | (56.46) | 463.94 | (151) | (950) | (1,402) | (2,016) | (2,596) | (3,493) | (3,982) | (4,496) | (5,149) |
| Brooklyn Navy Yard | 249.2 | (11.74) | 237.46 | 75 | (723) | (1,176) | (1,790) | (2,369) | (3,266) | (3,755) | (4,269) | (4,923) |
| Astoria 2, 3, & 5 | 902.3 | (97.90) | 804.40 | (492) | (1,290) | (1,743) | (2,357) | (2,936) | (3,833) | (4,322) | (4,836) | (5,490) |
| Astoria 2 | 158.0 | (17.14) | 140.86 | 172 | (626) | (1,079) | (1,693) | (2,273) | (3,170) | (3,658) | (4,172) | (4,826) |
| Astoria 3 | 371.1 | (40.26) | 330.84 | (18) | (816) | (1,269) | (1,883) | (2,463) | (3,360) | (3,848) | (4,362) | (5,016) |
| Astoria 5 | 373.2 | (40.49) | 332.71 | (20) | (818) | (1,271) | (1,885) | (2,464) | (3,362) | (3,850) | (4,364) | (5,018) |
| Ravenswood ST 01, 02, & 03 | 1,724.8 | (187.14) | 1,537.66 | (1,225) | (2,023) | (2,476) | (3,090) | (3,669) | (4,567) | (5,055) | (5,569) | (6,223) |
| Ravenswood ST 01 | 364.5 | (39.55) | 324.95 | (12) | (811) | (1,263) | (1,877) | (2,457) | (3,354) | (3,843) | (4,357) | (5,010) |
| Ravenswood ST 02 | 375.2 | (40.71) | 334.49 | (22) | (820) | (1,273) | (1,887) | (2,466) | (3,363) | (3,852) | (4,366) | (5,020) |
| Ravenswood ST 03 | 985.1 | (106.88) | 878.22 | (566) | (1,364) | (1,817) | (2,430) | (3,010) | (3,907) | (4,396) | (4,910) | (5,563) |
| Ravenswood CC 04 | 222.2 | (10.47) | 211.73 | 101 | (697) | (1,150) | (1,764) | (2,343) | (3,241) | (3,729) | (4,243) | (4,897) |
| East River 1, 2, 6, & 7 | 630.7 | (49.54) | 581.16 | (269) | (1,067) | (1,520) | (2,133) | (2,713) | (3,610) | (4,099) | (4,613) | (5,266) |

| Statewide System Margin | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | Year | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 |
| Statewide System Margin Summer Peak - Baseline Expected Summer Weather, Normal Transfer Criteria (MW) (1) | | | | 312 | (486) | (938) | (1,552) | (2,132) | (3,029) | (3,518) | (4,032) | (4,685) |
| Unit Name | Summer DMNC (MW) | NERC 5-Year Class Average De-Rate (MW) | Summer De-Rated Capability (MW) | Transmission Security Margin Considering Impact of Generator Outage (Retire, Mothball, IIFO) | | | | | | | | |
| East River 1 | 153.2 | (7.22) | 145.98 | 167 | (632) | (1,084) | (1,698) | (2,278) | (3,175) | (3,664) | (4,178) | (4,831) |
| East River 2 | 154.5 | (7.28) | 147.22 | 165 | (633) | (1,086) | (1,699) | (2,279) | (3,176) | (3,665) | (4,179) | (4,832) |
| East River 6 | 141.5 | (15.35) | 126.15 | 186 | (612) | (1,065) | (1,678) | (2,258) | (3,155) | (3,644) | (4,158) | (4,811) |
| East River 7 | 181.5 | (19.69) | 161.81 | 151 | (647) | (1,100) | (1,714) | (2,294) | (3,191) | (3,679) | (4,193) | (4,847) |
| Linden Cogen | 748.2 | (35.24) | 712.96 | (400) | (1,199) | (1,651) | (2,265) | (2,845) | (3,742) | (4,231) | (4,745) | (5,398) |
| KIAC_JFK (BTM:NG) | 105.4 | (4.96) | 100.44 | 212 | (586) | (1,039) | (1,653) | (2,232) | (3,129) | (3,618) | (4,132) | (4,786) |
| Gowanus 5 & 6[4] | 79.9 | (8.25) | 71.65 | 241 | (557) | (1,010) | (1,624) | (2,203) | - | - | - | - |
| Gowanus 5[4] | 40.0 | (4.13) | 35.87 | 277 | (521) | (974) | (1,588) | (2,168) | - | - | - | - |
| Gowanus 6[4] | 39.9 | (4.12) | 35.78 | 277 | (521) | (974) | (1,588) | (2,168) | - | - | - | - |
| Kent[4] | 46.0 | (4.75) | 41.25 | 271 | (527) | (980) | (1,593) | (2,173) | - | - | - | - |
| Pouch[4] | 44.7 | (4.61) | 40.09 | 272 | (526) | (979) | (1,592) | (2,172) | - | - | - | - |
| Hellgate 1 & 2[4] | 79.5 | (8.20) | 71.30 | 241 | (557) | (1,010) | (1,623) | (2,203) | - | - | - | - |
| Hellgate 1[4] | 39.9 | (4.12) | 35.78 | 277 | (521) | (974) | (1,588) | (2,168) | - | - | - | - |
| Hellgate 2[4] | 39.6 | (4.09) | 35.51 | 277 | (521) | (974) | (1,588) | (2,167) | - | - | - | - |
| Harlem River 1 & 2[4] | 79.5 | (8.20) | 71.30 | 241 | (557) | (1,010) | (1,623) | (2,203) | - | - | - | - |
| Harlem River 1[4] | 39.9 | (4.12) | 35.78 | 277 | (521) | (974) | (1,588) | (2,168) | - | - | - | - |
| Harlem River 2[4] | 39.6 | (4.09) | 35.51 | 277 | (521) | (974) | (1,588) | (2,167) | - | - | - | - |
| Vernon Blvd 2 & 3[4] | 79.9 | (8.25) | 71.65 | 241 | (557) | (1,010) | (1,624) | (2,203) | - | - | - | - |

| Statewide System Margin | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Year | | | | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 |
| Statewide System Margin Summer Peak - Baseline Expected Summer Weather, Normal Transfer Criteria (MW) (1) | | | | 312 | (486) | (938) | (1,552) | (2,132) | (3,029) | (3,518) | (4,032) | (4,685) |
| Unit Name | Summer DMNC (MW) | NERC 5-Year Class Average De-Rate (MW) | Summer De-Rated Capability (MW) | Transmission Security Margin Considering Impact of Generator Outage (Retire, Mothball, IIFO) | | | | | | | | |
| Vernon Blvd 2[4] | 40.0 | (4.13) | 35.87 | 277 | (521) | (974) | (1,588) | (2,168) | - | - | - | - |
| Vernon Blvd 3[4] | 39.9 | (4.12) | 35.78 | 277 | (521) | (974) | (1,588) | (2,168) | - | - | - | - |
| Astoria CC 1 & 2 | 474.0 | (22.33) | 451.67 | (139) | (937) | (1,390) | (2,004) | (2,583) | (3,481) | (3,969) | (4,483) | (5,137) |
| Astoria CC 1 | 237.0 | (11.16) | 225.84 | 87 | (711) | (1,164) | (1,778) | (2,358) | (3,255) | (3,743) | (4,257) | (4,911) |
| Astoria CC 2 | 237.0 | (11.16) | 225.84 | 87 | (711) | (1,164) | (1,778) | (2,358) | (3,255) | (3,743) | (4,257) | (4,911) |
| Astoria East Energy CC1 & CC2 | 582.8 | (27.45) | 555.35 | (243) | (1,041) | (1,494) | (2,107) | (2,687) | (3,584) | (4,073) | (4,587) | (5,241) |
| Astoria East Energy - CC1 | 291.4 | (13.72) | 277.68 | 35 | (763) | (1,216) | (1,830) | (2,409) | (3,307) | (3,795) | (4,309) | (4,963) |
| Astoria East Energy - CC2 | 291.4 | (13.72) | 277.68 | 35 | (763) | (1,216) | (1,830) | (2,409) | (3,307) | (3,795) | (4,309) | (4,963) |
| Astoria Energy 2 - CC3 & CC4 | 570.3 | (26.86) | 543.44 | (231) | (1,029) | (1,482) | (2,096) | (2,675) | (3,572) | (4,061) | (4,575) | (5,229) |
| Astoria Energy 2 - CC3 | 285.0 | (13.42) | 271.58 | 41 | (757) | (1,210) | (1,824) | (2,403) | (3,301) | (3,789) | (4,303) | (4,957) |
| Astoria Energy 2 - CC4 | 285.3 | (13.44) | 271.86 | 41 | (757) | (1,210) | (1,824) | (2,404) | (3,301) | (3,789) | (4,303) | (4,957) |
| Bayonne EC CT G1 through G10 | 604.8 | (54.67) | 550.13 | (238) | (1,036) | (1,489) | (2,102) | (2,682) | (3,579) | (4,068) | (4,582) | (5,235) |
| Bayonne EC CTG1 | 62.0 | (5.60) | 56.40 | 256 | (542) | (995) | (1,608) | (2,188) | (3,085) | (3,574) | (4,088) | (4,742) |
| Bayonne EC CTG2 | 58.0 | (5.24) | 52.76 | 260 | (538) | (991) | (1,605) | (2,185) | (3,082) | (3,570) | (4,084) | (4,738) |
| Bayonne EC CTG3 | 58.1 | (5.25) | 52.85 | 260 | (538) | (991) | (1,605) | (2,185) | (3,082) | (3,570) | (4,084) | (4,738) |
| Bayonne EC CTG4 | 61.1 | (5.52) | 55.58 | 257 | (541) | (994) | (1,608) | (2,187) | (3,085) | (3,573) | (4,087) | (4,741) |
| Bayonne EC CTG5 | 61.8 | (5.59) | 56.21 | 256 | (542) | (995) | (1,608) | (2,188) | (3,085) | (3,574) | (4,088) | (4,741) |
| Bayonne EC CTG6 | 61.4 | (5.55) | 55.85 | 257 | (541) | (994) | (1,608) | (2,188) | (3,085) | (3,573) | (4,087) | (4,741) |
| Bayonne EC CTG7 | 59.7 | (5.40) | 54.30 | 258 | (540) | (993) | (1,606) | (2,186) | (3,083) | (3,572) | (4,086) | (4,740) |
| Bayonne EC CTG8 | 60.0 | (5.42) | 54.58 | 258 | (540) | (993) | (1,607) | (2,186) | (3,084) | (3,572) | (4,086) | (4,740) |

| Statewide System Margin | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Year | | | | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 |
| Statewide System Margin Summer Peak - Baseline Expected Summer Weather, Normal Transfer Criteria (MW) (1) | | | | 312 | (486) | (938) | (1,552) | (2,132) | (3,029) | (3,518) | (4,032) | (4,685) |
| Unit Name | Summer DMNC (MW) | NERC 5-Year Class Average De-Rate (MW) | Summer De-Rated Capability (MW) | Transmission Security Margin Considering Impact of Generator Outage (Retire, Mothball, IIFO) | | | | | | | | |
| Bayonne EC CTG9 | 61.3 | (5.54) | 55.76 | 257 | (541) | (994) | (1,608) | (2,188) | (3,085) | (3,573) | (4,087) | (4,741) |
| Bayonne EC CTG10 | 61.4 | (5.55) | 55.85 | 257 | (541) | (994) | (1,608) | (2,188) | (3,085) | (3,573) | (4,087) | (4,741) |
| Greenport IC 4, 5, & 6 | 5.6 | (0.83) | 4.77 | 308 | (490) | (943) | (1,557) | (2,137) | (3,034) | (3,522) | (4,036) | (4,690) |
| Greenport IC 4 | 1.0 | (0.15) | 0.85 | 312 | (486) | (939) | (1,553) | (2,133) | (3,030) | (3,518) | (4,032) | (4,686) |
| Greenport IC 5 | 1.5 | (0.22) | 1.28 | 311 | (487) | (940) | (1,553) | (2,133) | (3,030) | (3,519) | (4,033) | (4,687) |
| Greenport IC 6 | 3.1 | (0.46) | 2.64 | 310 | (488) | (941) | (1,555) | (2,134) | (3,032) | (3,520) | (4,034) | (4,688) |
| Freeport 1-2, 1-3, & 2-3 | 19.2 | (2.21) | 16.99 | 296 | (503) | (955) | (1,569) | (2,149) | (3,046) | (3,535) | (4,049) | (4,702) |
| Freeport 1-2 | 2.3 | (0.34) | 1.96 | 311 | (488) | (940) | (1,554) | (2,134) | (3,031) | (3,520) | (4,034) | (4,687) |
| Freeport 1-3 | 2.7 | (0.40) | 2.30 | 310 | (488) | (941) | (1,554) | (2,134) | (3,031) | (3,520) | (4,034) | (4,688) |
| Freeport 2-3 | 14.2 | (1.47) | 12.73 | 300 | (498) | (951) | (1,565) | (2,144) | (3,042) | (3,530) | (4,044) | (4,698) |
| Charles P Killer 09 through 14 | 13.5 | (1.78) | 11.72 | 301 | (497) | (950) | (1,564) | (2,143) | (3,041) | (3,529) | (4,043) | (4,697) |
| Charles P Keller 09 | 1.6 | (0.21) | 1.39 | 311 | (487) | (940) | (1,553) | (2,133) | (3,030) | (3,519) | (4,033) | (4,687) |
| Charles P Keller 10 | 1.6 | (0.21) | 1.39 | 311 | (487) | (940) | (1,553) | (2,133) | (3,030) | (3,519) | (4,033) | (4,687) |
| Charles P Keller 11 | 2.4 | (0.32) | 2.08 | 310 | (488) | (941) | (1,554) | (2,134) | (3,031) | (3,520) | (4,034) | (4,687) |
| Charles P Keller 12 | 2.5 | (0.33) | 2.17 | 310 | (488) | (941) | (1,554) | (2,134) | (3,031) | (3,520) | (4,034) | (4,687) |
| Charles P Keller 13 | 2.5 | (0.33) | 2.17 | 310 | (488) | (941) | (1,554) | (2,134) | (3,031) | (3,520) | (4,034) | (4,687) |
| Charles P Keller 14 | 2.9 | (0.38) | 2.52 | 310 | (488) | (941) | (1,555) | (2,134) | (3,031) | (3,520) | (4,034) | (4,688) |
| Wading River 1, 2, & 3 | 214.8 | (22.17) | 192.63 | 120 | (678) | (1,131) | (1,745) | (2,324) | (3,222) | (3,710) | (4,224) | (4,878) |
| Wading River 1 | 77.6 | (8.01) | 69.59 | 243 | (555) | (1,008) | (1,622) | (2,201) | (3,099) | (3,587) | (4,101) | (4,755) |
| Wading River 2 | 64.3 | (6.64) | 57.66 | 255 | (543) | (996) | (1,610) | (2,189) | (3,087) | (3,575) | (4,089) | (4,743) |

| Statewide System Margin | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | Year | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 |
| Statewide System Margin Summer Peak - Baseline Expected Summer Weather, Normal Transfer Criteria (MW) (1) | | | | 312 | (486) | (938) | (1,552) | (2,132) | (3,029) | (3,518) | (4,032) | (4,685) |
| Unit Name | Summer DMNC (MW) | NERC 5-Year Class Average De-Rate (MW) | Summer De-Rated Capability (MW) | Transmission Security Margin Considering Impact of Generator Outage (Retire, Mothball, IIFO) | | | | | | | | |
| Wading River 3 | 72.9 | (7.52) | 65.38 | 247 | (551) | (1,004) | (1,617) | (2,197) | (3,094) | (3,583) | (4,097) | (4,751) |
| Barrett ST 01 & 02 | 380.5 | (41.28) | 339.22 | (27) | (825) | (1,278) | (1,891) | (2,471) | (3,368) | (3,857) | (4,371) | (5,024) |
| Barrett ST 01 | 192.0 | (20.83) | 171.17 | 141 | (657) | (1,110) | (1,723) | (2,303) | (3,200) | (3,689) | (4,203) | (4,856) |
| Barrett ST 02 | 188.5 | (20.45) | 168.05 | 144 | (654) | (1,106) | (1,720) | (2,300) | (3,197) | (3,686) | (4,200) | (4,853) |
| Barrett GT 01 through 12 | 246.6 | (23.47) | 223.13 | 89 | (709) | (1,162) | (1,775) | (2,355) | (3,252) | (3,741) | (4,255) | (4,908) |
| Barrett GT 01 | 13.7 | (1.41) | 12.29 | 300 | (498) | (951) | (1,564) | (2,144) | (3,041) | (3,530) | (4,044) | (4,698) |
| Barrett GT 02 | 13.6 | (1.40) | 12.20 | 300 | (498) | (951) | (1,564) | (2,144) | (3,041) | (3,530) | (4,044) | (4,697) |
| Barrett 03 | 12.2 | (1.26) | 10.94 | 302 | (497) | (949) | (1,563) | (2,143) | (3,040) | (3,529) | (4,043) | (4,696) |
| Barrett 04 | 14.5 | (1.50) | 13.00 | 299 | (499) | (951) | (1,565) | (2,145) | (3,042) | (3,531) | (4,045) | (4,698) |
| Barrett 05 | 12.0 | (1.24) | 10.76 | 302 | (496) | (949) | (1,563) | (2,143) | (3,040) | (3,528) | (4,042) | (4,696) |
| Barrett 06 | 12.9 | (1.33) | 11.57 | 301 | (497) | (950) | (1,564) | (2,143) | (3,040) | (3,529) | (4,043) | (4,697) |
| Barrett 08 | 12.8 | (1.32) | 11.48 | 301 | (497) | (950) | (1,564) | (2,143) | (3,040) | (3,529) | (4,043) | (4,697) |
| Barrett 09 | 38.6 | (3.49) | 35.11 | 277 | (521) | (974) | (1,587) | (2,167) | (3,064) | (3,553) | (4,067) | (4,720) |
| Barrett 10 | 39.2 | (3.54) | 35.66 | 277 | (521) | (974) | (1,588) | (2,167) | (3,065) | (3,553) | (4,067) | (4,721) |
| Barrett 11 | 38.2 | (3.45) | 34.75 | 278 | (520) | (973) | (1,587) | (2,167) | (3,064) | (3,552) | (4,066) | (4,720) |
| Barrett 12 | 38.9 | (3.52) | 35.38 | 277 | (521) | (974) | (1,587) | (2,167) | (3,064) | (3,553) | (4,067) | (4,721) |
| Northport 1, 2, 3, and 4 | 1,582.2 | (171.67) | 1,410.53 | (1,098) | (1,896) | (2,349) | (2,963) | (3,542) | (4,439) | (4,928) | (5,442) | (6,096) |
| Northport 1 | 399.0 | (43.29) | 355.71 | (43) | (841) | (1,294) | (1,908) | (2,487) | (3,385) | (3,873) | (4,387) | (5,041) |
| Northport 2 | 399.0 | (43.29) | 355.71 | (43) | (841) | (1,294) | (1,908) | (2,487) | (3,385) | (3,873) | (4,387) | (5,041) |
| Northport 3 | 386.2 | (41.90) | 344.30 | (32) | (830) | (1,283) | (1,896) | (2,476) | (3,373) | (3,862) | (4,376) | (5,030) |

| Statewide System Margin | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Year | | | | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 |
| Statewide System Margin Summer Peak - Baseline Expected Summer Weather, Normal Transfer Criteria (MW) (1) | | | | 312 | (486) | (938) | (1,552) | (2,132) | (3,029) | (3,518) | (4,032) | (4,685) |
| Unit Name | Summer DMNC (MW) | NERC 5-Year Class Average De-Rate (MW) | Summer De-Rated Capability (MW) | Transmission Security Margin Considering Impact of Generator Outage (Retire, Mothball, IIFO) | | | | | | | | |
| Northport 4 | 398.0 | (43.18) | 354.82 | (42) | (840) | (1,293) | (1,907) | (2,487) | (3,384) | (3,872) | (4,386) | (5,040) |
| Port Jefferson GT 02 & 03 | 79.3 | (8.18) | 71.12 | 241 | (557) | (1,010) | (1,623) | (2,203) | (3,100) | (3,589) | (4,103) | (4,756) |
| Port Jefferson GT 02 | 39.1 | (4.04) | 35.06 | 277 | (521) | (974) | (1,587) | (2,167) | (3,064) | (3,553) | (4,067) | (4,720) |
| Port Jefferson GT 03 | 40.2 | (4.15) | 36.05 | 276 | (522) | (974) | (1,588) | (2,168) | (3,065) | (3,554) | (4,068) | (4,721) |
| Port Jefferson 3 & 4 | 380.0 | (41.23) | 338.77 | (26) | (824) | (1,277) | (1,891) | (2,471) | (3,368) | (3,856) | (4,370) | (5,024) |
| Port Jefferson 3 | 191.0 | (20.72) | 170.28 | 142 | (656) | (1,109) | (1,722) | (2,302) | (3,199) | (3,688) | (4,202) | (4,856) |
| Port Jefferson 4 | 189.0 | (20.51) | 168.49 | 144 | (654) | (1,107) | (1,721) | (2,300) | (3,197) | (3,686) | (4,200) | (4,854) |
| Hempstead (RR) | 74.2 | (8.05) | 66.15 | 246 | (552) | (1,005) | (1,618) | (2,198) | (3,095) | (3,584) | (4,098) | (4,751) |
| Glenwood GT 02, 04, & 05 | 123.9 | (12.79) | 111.11 | 201 | (597) | (1,050) | (1,663) | (2,243) | (3,140) | (3,629) | (4,143) | (4,796) |
| Glenwood GT 02 | 40.3 | (4.16) | 36.14 | 276 | (522) | (975) | (1,588) | (2,168) | (3,065) | (3,554) | (4,068) | (4,721) |
| Glenwood GT 04 | 41.9 | (4.32) | 37.58 | 275 | (523) | (976) | (1,590) | (2,169) | (3,067) | (3,555) | (4,069) | (4,723) |
| Glenwood GT 05 | 41.7 | (4.30) | 37.40 | 275 | (523) | (976) | (1,589) | (2,169) | (3,066) | (3,555) | (4,069) | (4,723) |
| Holtsville 01 through 10 | 527.9 | (47.72) | 480.18 | (168) | (966) | (1,419) | (2,032) | (2,612) | (3,509) | (3,998) | (4,512) | (5,165) |
| Holtsville 01 | 54.2 | (4.90) | 49.30 | 263 | (535) | (988) | (1,601) | (2,181) | (3,078) | (3,567) | (4,081) | (4,735) |
| Holtsville 02 | 56.8 | (5.13) | 51.67 | 261 | (537) | (990) | (1,604) | (2,183) | (3,081) | (3,569) | (4,083) | (4,737) |
| Holtsville 03 | 51.2 | (4.63) | 46.57 | 266 | (532) | (985) | (1,599) | (2,178) | (3,076) | (3,564) | (4,078) | (4,732) |
| Holtsville 04 | 53.0 | (4.79) | 48.21 | 264 | (534) | (987) | (1,600) | (2,180) | (3,077) | (3,566) | (4,080) | (4,733) |
| Holtsville 05 | 52.6 | (4.76) | 47.84 | 265 | (533) | (986) | (1,600) | (2,180) | (3,077) | (3,565) | (4,079) | (4,733) |
| Holtsville 06 | 49.4 | (4.47) | 44.93 | 268 | (531) | (983) | (1,597) | (2,177) | (3,074) | (3,563) | (4,077) | (4,730) |
| Holtsville 07 | 54.0 | (4.88) | 49.12 | 263 | (535) | (988) | (1,601) | (2,181) | (3,078) | (3,567) | (4,081) | (4,734) |

| Statewide System Margin | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Year | | | | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 |
| Statewide System Margin Summer Peak - Baseline Expected Summer Weather, Normal Transfer Criteria (MW) (1) | | | | 312 | (486) | (938) | (1,552) | (2,132) | (3,029) | (3,518) | (4,032) | (4,685) |
| Unit Name | Summer DMNC (MW) | NERC 5-Year Class Average De-Rate (MW) | Summer De-Rated Capability (MW) | Transmission Security Margin Considering Impact of Generator Outage (Retire, Mothball, IIFO) | | | | | | | | |
| Holtsville 08 | 49.9 | (4.51) | 45.39 | 267 | (531) | (984) | (1,597) | (2,177) | (3,074) | (3,563) | (4,077) | (4,731) |
| Holtsville 09 | 55.4 | (5.01) | 50.39 | 262 | (536) | (989) | (1,602) | (2,182) | (3,079) | (3,568) | (4,082) | (4,736) |
| Holtsville 10 | 51.4 | (4.65) | 46.75 | 266 | (532) | (985) | (1,599) | (2,179) | (3,076) | (3,564) | (4,078) | (4,732) |
| Shoreham GT 3 & 4 | 84.7 | (8.74) | 75.96 | 237 | (562) | (1,014) | (1,628) | (2,208) | (3,105) | (3,594) | (4,108) | (4,761) |
| Shoreham GT3 | 42.9 | (4.43) | 38.47 | 274 | (524) | (977) | (1,591) | (2,170) | (3,067) | (3,556) | (4,070) | (4,724) |
| Shoreham GT4 | 41.8 | (4.31) | 37.49 | 275 | (523) | (976) | (1,590) | (2,169) | (3,066) | (3,555) | (4,069) | (4,723) |
| East Hampton GT 01, 2, 3, & 4 | 23.8 | (2.47) | 21.33 | 291 | (507) | (960) | (1,573) | (2,153) | (3,050) | (3,539) | (4,053) | (4,707) |
| East Hampton GT 01 | 18.4 | (1.66) | 16.74 | 296 | (502) | (955) | (1,569) | (2,149) | (3,046) | (3,534) | (4,048) | (4,702) |
| East Hampton 2 | 1.8 | (0.27) | 1.53 | 311 | (487) | (940) | (1,554) | (2,133) | (3,030) | (3,519) | (4,033) | (4,687) |
| East Hampton 3 | 1.8 | (0.27) | 1.53 | 311 | (487) | (940) | (1,554) | (2,133) | (3,030) | (3,519) | (4,033) | (4,687) |
| East Hampton 4 | 1.8 | (0.27) | 1.53 | 311 | (487) | (940) | (1,554) | (2,133) | (3,030) | (3,519) | (4,033) | (4,687) |
| Southold 1 | 9.5 | (0.98) | 8.52 | 304 | (494) | (947) | (1,561) | (2,140) | (3,037) | (3,526) | (4,040) | (4,694) |
| S Hampton 1 | 8.1 | (0.84) | 7.26 | 305 | (493) | (946) | (1,559) | (2,139) | (3,036) | (3,525) | (4,039) | (4,693) |
| Freeport CT 1 & 2 | 88.8 | (9.16) | 79.64 | 233 | (565) | (1,018) | (1,632) | (2,211) | (3,109) | (3,597) | (4,111) | (4,765) |
| Freeport CT 1 | 45.8 | (4.73) | 41.07 | 271 | (527) | (980) | (1,593) | (2,173) | (3,070) | (3,559) | (4,073) | (4,726) |
| Freeport CT 2 | 43.0 | (4.44) | 38.56 | 274 | (524) | (977) | (1,591) | (2,170) | (3,067) | (3,556) | (4,070) | (4,724) |
| Flynn | 139.5 | (6.57) | 132.93 | 180 | (619) | (1,071) | (1,685) | (2,265) | (3,162) | (3,651) | (4,165) | (4,818) |
| Greenport GT1 | 51.0 | (4.61) | 46.39 | 266 | (532) | (985) | (1,598) | (2,178) | (3,075) | (3,564) | (4,078) | (4,732) |
| Far Rockaway GT1 & GT2[3] | - | - | - | - | - | - | - | - | - | - | - | - |
| Far Rockaway GT1[3] | - | - | - | - | - | - | - | - | - | - | - | - |

| Statewide System Margin | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Year | | | | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 |
| Statewide System Margin Summer Peak - Baseline Expected Summer Weather, Normal Transfer Criteria (MW) (1) | | | | 312 | (486) | (938) | (1,552) | (2,132) | (3,029) | (3,518) | (4,032) | (4,685) |
| Unit Name | Summer DMNC (MW) | NERC 5-Year Class Average De-Rate (MW) | Summer De-Rated Capability (MW) | Transmission Security Margin Considering Impact of Generator Outage (Retire, Mothball, IIFO) | | | | | | | | |
| Far Rockaway GT2[3] | - | - | - | - | - | - | - | - | - | - | - | - |
| Bethpage | 51.0 | (2.40) | 48.60 | 264 | (534) | (987) | (1,601) | (2,180) | (3,078) | (3,566) | (4,080) | (4,734) |
| Bethpage 3 | 75.7 | (3.57) | 72.13 | 240 | (558) | (1,011) | (1,624) | (2,204) | (3,101) | (3,590) | (4,104) | (4,757) |
| Bethpage GT4 | 43.7 | (4.51) | 39.19 | 273 | (525) | (978) | (1,591) | (2,171) | (3,068) | (3,557) | (4,071) | (4,724) |
| Stony Brook (BTM:NG) | 0.0 | 0.00 | 0.00 | 312 | (486) | (938) | (1,552) | (2,132) | (3,029) | (3,518) | (4,032) | (4,685) |
| Brentwood | 45.0 | (4.64) | 40.36 | 272 | (526) | (979) | (1,592) | (2,172) | (3,069) | (3,558) | (4,072) | (4,726) |
| Pilgrim GT1 & GT2 | 83.6 | (8.63) | 74.97 | 238 | (561) | (1,013) | (1,627) | (2,207) | (3,104) | (3,593) | (4,107) | (4,760) |
| Pilgrim GT1 | 41.3 | (4.26) | 37.04 | 275 | (523) | (975) | (1,589) | (2,169) | (3,066) | (3,555) | (4,069) | (4,722) |
| Pilgrim GT2 | 42.3 | (4.37) | 37.93 | 275 | (524) | (976) | (1,590) | (2,170) | (3,067) | (3,556) | (4,070) | (4,723) |
| Pinelawn Power 1[3] | - | - | - | - | - | - | - | - | - | - | - | - |
| Caithness_CC_1 | 313.5 | (14.77) | 298.73 | 14 | (784) | (1,237) | (1,851) | (2,430) | (3,328) | (3,816) | (4,330) | (4,984) |
| Islip (RR) | 8.0 | (0.87) | 7.13 | 305 | (493) | (946) | (1,559) | (2,139) | (3,036) | (3,525) | (4,039) | (4,692) |
| Babylon (RR) | 15.7 | (1.70) | 14.00 | 298 | (500) | (952) | (1,566) | (2,146) | (3,043) | (3,532) | (4,046) | (4,699) |
| Huntington (RR) | 24.8 | (2.69) | 22.11 | 290 | (508) | (961) | (1,574) | (2,154) | (3,051) | (3,540) | (4,054) | (4,707) |

Notes

1. Utilizes the Higher Policy Statewide System Margin for Summer Peak with Expected Weather.
2. Utilizes the next largest generation contingency outage which is the loss of the Cricket Valley CC1, CC2, & CC3.
3. Unit is modeled out of service beginning in 2026 in the baseline margin calculation.
4. Unit is modeled out of service beginning in 2031 in the baseline margin calculation.

**Figure 52: AOI - Lower Hudson Valley Transmission Security Margin**

| Lower Hudson Valley | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Year | | | | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 |
| Lower Hudson Valley Transmission Security Margin, Summer Peak - Baseline Expected Summer Weather, Normal Transfer Criteria (MW) (1) | | | | 2,167 | 1,854 | 1,779 | 1,580 | 1,123 | 468 | 220 | (57) | (354) |
| Unit Name | Summer DMNC (MW) | NERC 5-Year Class Average De-Rate (MW) | Summer De-Rated Capability (MW) | Transmission Security Margin Considering Impact of Generator Outage (Retire, Mothball, IIFO) | | | | | | | | |
| Bowline 1 & 2 | 1,136.3 | (123.29) | 1,013.01 | 1,154 | 841 | 766 | 567 | 110 | (545) | (793) | (1,070) | (1,367) |
| Bowline 1 | 565.1 | (61.31) | 503.79 | 1,664 | 1,351 | 1,275 | 1,076 | 619 | (36) | (284) | (561) | (858) |
| Bowline 2 | 571.2 | (61.98) | 509.22 | 1,658 | 1,345 | 1,269 | 1,071 | 614 | (41) | (289) | (566) | (863) |
| Danskammer 1, 2, 3, & 4 | 498.2 | (54.05) | 444.15 | 1,723 | 1,410 | 1,334 | 1,136 | 679 | 24 | (224) | (501) | (798) |
| Danskammer 1 | 68.8 | (7.46) | 61.34 | 2,106 | 1,793 | 1,717 | 1,518 | 1,062 | 407 | 159 | (119) | (415) |
| Danskammer 2 | 64.9 | (7.04) | 57.86 | 2,110 | 1,796 | 1,721 | 1,522 | 1,065 | 410 | 162 | (115) | (412) |
| Danskammer 3 | 140.2 | (15.21) | 124.99 | 2,042 | 1,729 | 1,654 | 1,455 | 998 | 343 | 95 | (182) | (479) |
| Danskammer 4 | 224.3 | (24.34) | 199.96 | 1,967 | 1,654 | 1,579 | 1,380 | 923 | 268 | 20 | (257) | (554) |
| Roseton 1 & 2 | 1,224.1 | (132.81) | 1,091.29 | 1,076 | 763 | 687 | 488 | 32 | (623) | (871) | (1,149) | (1,445) |
| Roseton 1 | 616.8 | (66.92) | 549.88 | 1,618 | 1,304 | 1,229 | 1,030 | 573 | (82) | (330) | (607) | (904) |
| Roseton 2 | 607.3 | (65.89) | 541.41 | 1,626 | 1,313 | 1,237 | 1,038 | 582 | (74) | (321) | (599) | (895) |
| Hillburn GT | 34.7 | (3.14) | 31.56 | 2,136 | 1,823 | 1,747 | 1,548 | 1,091 | 436 | 188 | (89) | (385) |
| Shoemaker GT | 32.3 | (2.92) | 29.38 | 2,138 | 1,825 | 1,749 | 1,550 | 1,094 | 438 | 191 | (87) | (383) |
| DCRRA | 6.3 | (0.68) | 5.62 | 2,162 | 1,849 | 1,773 | 1,574 | 1,117 | 462 | 214 | (63) | (359) |
| CPV Valley CC1 & CC2 | 649.8 | (30.61) | 619.19 | 1,548 | 1,235 | 1,159 | 961 | 504 | (151) | (399) | (676) | (973) |
| CPV Valley CC1 | 320.4 | (15.09) | 305.31 | 1,862 | 1,549 | 1,473 | 1,274 | 818 | 163 | (85) | (363) | (659) |
| CPV Valley CC2 | 329.4 | (15.51) | 313.89 | 1,854 | 1,540 | 1,465 | 1,266 | 809 | 154 | (94) | (371) | (668) |
| Cricket Valley CC1, CC2, & CC3 | 1,021.6 | (48.12) | 973.48 | 1,194 | 881 | 805 | 606 | 149 | (506) | (753) | (1,031) | (1,327) |
| Cricket Valley CC1 | 349.7 | (16.47) | 333.23 | 1,834 | 1,521 | 1,445 | 1,247 | 790 | 135 | (113) | (391) | (687) |

| Lower Hudson Valley | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | Year | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 |
| Lower Hudson Valley Transmission Security Margin, Summer Peak - Baseline Expected Summer Weather, Normal Transfer Criteria (MW) (1) | | | | 2,167 | 1,854 | 1,779 | 1,580 | 1,123 | 468 | 220 | (57) | (354) |
| Unit Name | Summer DMNC (MW) | NERC 5-Year Class Average De-Rate (MW) | Summer De-Rated Capability (MW) | Transmission Security Margin Considering Impact of Generator Outage (Retire, Mothball, IIFO) | | | | | | | | |
| Cricket Valley CC2 | 345.5 | (16.27) | 329.23 | 1,838 | 1,525 | 1,449 | 1,251 | 794 | 139 | (109) | (386) | (683) |
| Cricket Valley CC3 | 326.4 | (15.37) | 311.03 | 1,856 | 1,543 | 1,468 | 1,269 | 812 | 157 | (91) | (368) | (665) |
| Wheelabrator Westchester | 53.5 | (5.80) | 47.70 | 2,120 | 1,807 | 1,731 | 1,532 | 1,075 | 420 | 172 | (105) | (402) |
| Arthur Kill ST 2 & 3 | 883.6 | (95.87) | 787.73 | 1,380 | 1,067 | 991 | 792 | 335 | (320) | (568) | (845) | (1,142) |
| Arthur Kill ST 2 | 363.2 | (39.41) | 323.79 | 1,844 | 1,531 | 1,455 | 1,256 | 799 | 144 | (104) | (381) | (678) |
| Arthur Kill ST 3 | 520.4 | (56.46) | 463.94 | 1,703 | 1,390 | 1,315 | 1,116 | 659 | 4 | (244) | (521) | (818) |
| Brooklyn Navy Yard | 249.2 | (11.74) | 237.46 | 1,930 | 1,617 | 1,541 | 1,342 | 885 | 230 | (17) | (295) | (591) |
| Astoria 2, 3, & 5 | 902.3 | (97.90) | 804.40 | 1,363 | 1,050 | 974 | 775 | 319 | (337) | (584) | (862) | (1,158) |
| Astoria 2 | 158.0 | (17.14) | 140.86 | 2,027 | 1,713 | 1,638 | 1,439 | 982 | 327 | 79 | (198) | (495) |
| Astoria 3 | 371.1 | (40.26) | 330.84 | 1,837 | 1,524 | 1,448 | 1,249 | 792 | 137 | (111) | (388) | (685) |
| Astoria 5 | 373.2 | (40.49) | 332.71 | 1,835 | 1,522 | 1,446 | 1,247 | 790 | 135 | (113) | (390) | (687) |
| Ravenswood ST 01, 02, & 03 | 1,724.8 | (187.14) | 1,537.66 | 630 | 317 | 241 | 42 | (415) | (1,070) | (1,318) | (1,595) | (1,891) |
| Ravenswood ST 01 | 364.5 | (39.55) | 324.95 | 1,842 | 1,529 | 1,454 | 1,255 | 798 | 143 | (105) | (382) | (679) |
| Ravenswood ST 02 | 375.2 | (40.71) | 334.49 | 1,833 | 1,520 | 1,444 | 1,245 | 788 | 133 | (114) | (392) | (688) |
| Ravenswood ST 03 | 985.1 | (106.88) | 878.22 | 1,289 | 976 | 900 | 702 | 245 | (410) | (658) | (935) | (1,232) |
| Ravenswood CC 04 | 222.2 | (10.47) | 211.73 | 1,956 | 1,643 | 1,567 | 1,368 | 911 | 256 | 8 | (269) | (566) |
| East River 1, 2, 6, & 7 | 630.7 | (49.54) | 581.16 | 1,586 | 1,273 | 1,197 | 999 | 542 | (113) | (361) | (638) | (935) |
| East River 1 | 153.2 | (7.22) | 145.98 | 2,021 | 1,708 | 1,633 | 1,434 | 977 | 322 | 74 | (203) | (500) |
| East River 2 | 154.5 | (7.28) | 147.22 | 2,020 | 1,707 | 1,631 | 1,433 | 976 | 321 | 73 | (204) | (501) |
| East River 6 | 141.5 | (15.35) | 126.15 | 2,041 | 1,728 | 1,652 | 1,454 | 997 | 342 | 94 | (183) | (480) |

| Lower Hudson Valley | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | Year | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 |
| Lower Hudson Valley Transmission Security Margin, Summer Peak - Baseline Expected Summer Weather, Normal Transfer Criteria (MW) (1) | | | | 2,167 | 1,854 | 1,779 | 1,580 | 1,123 | 468 | 220 | (57) | (354) |
| Unit Name | Summer DMNC (MW) | NERC 5-Year Class Average De-Rate (MW) | Summer De-Rated Capability (MW) | Transmission Security Margin Considering Impact of Generator Outage (Retire, Mothball, IIFO) | | | | | | | | |
| East River 7 | 181.5 | (19.69) | 161.81 | 2,006 | 1,693 | 1,617 | 1,418 | 961 | 306 | 58 | (219) | (516) |
| Linden Cogen | 748.2 | (35.24) | 712.96 | 1,454 | 1,141 | 1,066 | 867 | 410 | (245) | (493) | (770) | (1,067) |
| KIAC_JFK (BTM:NG) | 105.4 | (4.96) | 100.44 | 2,067 | 1,754 | 1,678 | 1,479 | 1,022 | 367 | 120 | (158) | (454) |
| Gowanus 5 & 6[2] | 79.9 | (8.25) | 71.65 | 2,096 | 1,783 | 1,707 | 1,508 | 1,051 | - | - | - | - |
| Gowanus 5[2] | 40.0 | (4.13) | 35.87 | 2,132 | 1,818 | 1,743 | 1,544 | 1,087 | - | - | - | - |
| Gowanus 6[2] | 39.9 | (4.12) | 35.78 | 2,132 | 1,819 | 1,743 | 1,544 | 1,087 | - | - | - | - |
| Kent[2] | 46.0 | (4.75) | 41.25 | 2,126 | 1,813 | 1,737 | 1,539 | 1,082 | - | - | - | - |
| Pouch[2] | 44.7 | (4.61) | 40.09 | 2,127 | 1,814 | 1,739 | 1,540 | 1,083 | - | - | - | - |
| Hellgate 1 & 2[2] | 79.5 | (8.20) | 71.30 | 2,096 | 1,783 | 1,707 | 1,508 | 1,052 | - | - | - | - |
| Hellgate 1[2] | 39.9 | (4.12) | 35.78 | 2,132 | 1,819 | 1,743 | 1,544 | 1,087 | - | - | - | - |
| Hellgate 2[2] | 39.6 | (4.09) | 35.51 | 2,132 | 1,819 | 1,743 | 1,544 | 1,087 | - | - | - | - |
| Harlem River 1 & 2[2] | 79.5 | (8.20) | 71.30 | 2,096 | 1,783 | 1,707 | 1,508 | 1,052 | - | - | - | - |
| Harlem River 1[2] | 39.9 | (4.12) | 35.78 | 2,132 | 1,819 | 1,743 | 1,544 | 1,087 | - | - | - | - |
| Harlem River 2[2] | 39.6 | (4.09) | 35.51 | 2,132 | 1,819 | 1,743 | 1,544 | 1,087 | - | - | - | - |
| Vernon Blvd 2 & 3[2] | 79.9 | (8.25) | 71.65 | 2,096 | 1,783 | 1,707 | 1,508 | 1,051 | - | - | - | - |
| Vernon Blvd 2[2] | 40.0 | (4.13) | 35.87 | 2,132 | 1,818 | 1,743 | 1,544 | 1,087 | - | - | - | - |
| Vernon Blvd 3[2] | 39.9 | (4.12) | 35.78 | 2,132 | 1,819 | 1,743 | 1,544 | 1,087 | - | - | - | - |
| Astoria CC 1 & 2 | 474.0 | (22.33) | 451.67 | 1,716 | 1,403 | 1,327 | 1,128 | 671 | 16 | (232) | (509) | (805) |
| Astoria CC 1 | 237.0 | (11.16) | 225.84 | 1,942 | 1,629 | 1,553 | 1,354 | 897 | 242 | (6) | (283) | (580) |
| Astoria CC 2 | 237.0 | (11.16) | 225.84 | 1,942 | 1,629 | 1,553 | 1,354 | 897 | 242 | (6) | (283) | (580) |

| Lower Hudson Valley | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | Year | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 |
| Lower Hudson Valley Transmission Security Margin, Summer Peak - Baseline Expected Summer Weather, Normal Transfer Criteria (MW) (1) | | | | 2,167 | 1,854 | 1,779 | 1,580 | 1,123 | 468 | 220 | (57) | (354) |
| Unit Name | Summer DMNC (MW) | NERC 5-Year Class Average De-Rate (MW) | Summer De-Rated Capability (MW) | Transmission Security Margin Considering Impact of Generator Outage (Retire, Mothball, IIFO) | | | | | | | | |
| Astoria East Energy CC1 & CC2 | 582.8 | (27.45) | 555.35 | 1,612 | 1,299 | 1,223 | 1,024 | 568 | (87) | (335) | (613) | (909) |
| Astoria East Energy - CC1 | 291.4 | (13.72) | 277.68 | 1,890 | 1,577 | 1,501 | 1,302 | 845 | 190 | (58) | (335) | (631) |
| Astoria East Energy - CC2 | 291.4 | (13.72) | 277.68 | 1,890 | 1,577 | 1,501 | 1,302 | 845 | 190 | (58) | (335) | (631) |
| Astoria Energy 2 - CC3 & CC4 | 570.3 | (26.86) | 543.44 | 1,624 | 1,311 | 1,235 | 1,036 | 579 | (76) | (323) | (601) | (897) |
| Astoria Energy 2 - CC3 | 285.0 | (13.42) | 271.58 | 1,896 | 1,583 | 1,507 | 1,308 | 851 | 196 | (52) | (329) | (625) |
| Astoria Energy 2 - CC4 | 285.3 | (13.44) | 271.86 | 1,896 | 1,582 | 1,507 | 1,308 | 851 | 196 | (52) | (329) | (626) |
| Bayonne EC CT G1 through G10 | 604.8 | (54.67) | 550.13 | 1,617 | 1,304 | 1,228 | 1,030 | 573 | (82) | (330) | (607) | (904) |
| Bayonne EC CTG1 | 62.0 | (5.60) | 56.40 | 2,111 | 1,798 | 1,722 | 1,523 | 1,067 | 411 | 164 | (114) | (410) |
| Bayonne EC CTG2 | 58.0 | (5.24) | 52.76 | 2,115 | 1,802 | 1,726 | 1,527 | 1,070 | 415 | 167 | (110) | (407) |
| Bayonne EC CTG3 | 58.1 | (5.25) | 52.85 | 2,115 | 1,802 | 1,726 | 1,527 | 1,070 | 415 | 167 | (110) | (407) |
| Bayonne EC CTG4 | 61.1 | (5.52) | 55.58 | 2,112 | 1,799 | 1,723 | 1,524 | 1,067 | 412 | 164 | (113) | (409) |
| Bayonne EC CTG5 | 61.8 | (5.59) | 56.21 | 2,111 | 1,798 | 1,722 | 1,524 | 1,067 | 412 | 164 | (113) | (410) |
| Bayonne EC CTG6 | 61.4 | (5.55) | 55.85 | 2,112 | 1,798 | 1,723 | 1,524 | 1,067 | 412 | 164 | (113) | (410) |
| Bayonne EC CTG7 | 59.7 | (5.40) | 54.30 | 2,113 | 1,800 | 1,724 | 1,525 | 1,069 | 414 | 166 | (112) | (408) |
| Bayonne EC CTG8 | 60.0 | (5.42) | 54.58 | 2,113 | 1,800 | 1,724 | 1,525 | 1,068 | 413 | 165 | (112) | (408) |
| Bayonne EC CTG9 | 61.3 | (5.54) | 55.76 | 2,112 | 1,799 | 1,723 | 1,524 | 1,067 | 412 | 164 | (113) | (410) |
| Bayonne EC CTG10 | 61.4 | (5.55) | 55.85 | 2,112 | 1,798 | 1,723 | 1,524 | 1,067 | 412 | 164 | (113) | (410) |

**Notes**

1. Utilizes the Higher Policy Transmission Security Margin for Summer Peak with Expected Weather.
2. Unit is modeled out of service beginning in 2031 in the baseline margin calculation.

**Figure 53: AOI - New York City Transmission Security Margin**

| New York City | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | Year | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 |
| New York City Transmission Security Margin, Summer Peak - Baseline Expected Summer Weather, Normal Transfer Criteria (MW) (1) | | | | 260 | 222 | 92 | (68) | (148) | (656) | (806) | (966) | (1,136) |
| Unit Name | Summer DMNC (MW) | NERC 5-Year Class Average De-Rate (MW) | Summer De-Rated Capability (MW) | Transmission Security Margin Considering Impact of Generator Outage (Retire, Mothball, IIFO) | | | | | | | | |
| Arthur Kill ST 2 & 3 | 883.6 | (95.87) | 787.73 | (528) | (566) | (696) | (856) | (936) | (1,444) | (1,594) | (1,754) | (1,924) |
| Arthur Kill ST 2 | 363.2 | (39.41) | 323.79 | (64) | (102) | (232) | (392) | (472) | (980) | (1,130) | (1,290) | (1,460) |
| Arthur Kill ST 3 | 520.4 | (56.46) | 463.94 | (204) | (242) | (372) | (532) | (612) | (1,120) | (1,270) | (1,430) | (1,600) |
| Brooklyn Navy Yard | 249.2 | (11.74) | 237.46 | 23 | (16) | (146) | (306) | (386) | (893) | (1,043) | (1,203) | (1,373) |
| Astoria 2, 3, & 5 | 902.3 | (97.90) | 804.40 | (544) | (583) | (713) | (873) | (953) | (1,460) | (1,610) | (1,770) | (1,940) |
| Astoria 2 | 158.0 | (17.14) | 140.86 | 119 | 81 | (49) | (209) | (289) | (797) | (947) | (1,107) | (1,277) |
| Astoria 3 | 371.1 | (40.26) | 330.84 | (71) | (109) | (239) | (399) | (479) | (987) | (1,137) | (1,297) | (1,467) |
| Astoria 5 | 373.2 | (40.49) | 332.71 | (73) | (111) | (241) | (401) | (481) | (989) | (1,139) | (1,299) | (1,469) |
| Ravenswood ST 01, 02, & 03[2] | 1,724.8 | (187.14) | 1,537.66 | (542) | (1,131) | (1,261) | (1,421) | (1,501) | (2,008) | (2,158) | (2,318) | (2,488) |
| Ravenswood ST 01 | 364.5 | (39.55) | 324.95 | (65) | (103) | (233) | (393) | (473) | (981) | (1,131) | (1,291) | (1,461) |
| Ravenswood ST 02 | 375.2 | (40.71) | 334.49 | (74) | (113) | (243) | (403) | (483) | (990) | (1,140) | (1,300) | (1,470) |
| Ravenswood ST 03 (2) | 985.1 | (106.88) | 878.22 | 117 | (471) | (271) | (761) | (841) | (1,349) | (1,499) | (1,659) | (1,829) |
| Ravenswood CC 04 | 222.2 | (10.47) | 211.73 | 48 | 10 | (120) | (280) | (360) | (868) | (1,018) | (1,178) | (1,348) |
| East River 1, 2, 6, & 7 | 630.7 | (49.54) | 581.16 | (321) | (359) | (489) | (649) | (729) | (1,237) | (1,387) | (1,547) | (1,717) |
| East River 1 | 153.2 | (7.22) | 145.98 | 114 | 76 | (54) | (214) | (294) | (802) | (952) | (1,112) | (1,282) |
| East River 2 | 154.5 | (7.28) | 147.22 | 113 | 74 | (56) | (216) | (296) | (803) | (953) | (1,113) | (1,283) |
| East River 6 | 141.5 | (15.35) | 126.15 | 134 | 96 | (34) | (194) | (274) | (782) | (932) | (1,092) | (1,262) |
| East River 7 | 181.5 | (19.69) | 161.81 | 98 | 60 | (70) | (230) | (310) | (818) | (968) | (1,128) | (1,298) |
| Linden Cogen | 748.2 | (35.24) | 712.96 | (453) | (491) | (621) | (781) | (861) | (1,369) | (1,519) | (1,679) | (1,849) |
| KIAC_JFK (BTM:NG) | 105.4 | (4.96) | 100.44 | 160 | 121 | (9) | (169) | (249) | (756) | (906) | (1,066) | (1,236) |

| New York City | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Year | | | | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 |
| New York City Transmission Security Margin, Summer Peak - Baseline Expected Summer Weather, Normal Transfer Criteria (MW) (1) | | | | 260 | 222 | 92 | (68) | (148) | (656) | (806) | (966) | (1,136) |
| Unit Name | Summer DMNC (MW) | NERC 5-Year Class Average De-Rate (MW) | Summer De-Rated Capability (MW) | Transmission Security Margin Considering Impact of Generator Outage (Retire, Mothball, IIFO) | | | | | | | | |
| Gowanus 5 & 6[3] | 79.9 | (8.25) | 71.65 | 188 | 150 | 20 | (140) | (220) | - | - | - | - |
| Gowanus 5[3] | 40.0 | (4.13) | 35.87 | 224 | 186 | 56 | (104) | (184) | - | - | - | - |
| Gowanus 6[3] | 39.9 | (4.12) | 35.78 | 224 | 186 | 56 | (104) | (184) | - | - | - | - |
| Kent[3] | 46.0 | (4.75) | 41.25 | 219 | 180 | 50 | (110) | (190) | - | - | - | - |
| Pouch[3] | 44.7 | (4.61) | 40.09 | 220 | 182 | 52 | (108) | (188) | - | - | - | - |
| Hellgate 1 & 2[3] | 79.5 | (8.20) | 71.30 | 189 | 150 | 20 | (140) | (220) | - | - | - | - |
| Hellgate 1[3] | 39.9 | (4.12) | 35.78 | 224 | 186 | 56 | (104) | (184) | - | - | - | - |
| Hellgate 2[3] | 39.6 | (4.09) | 35.51 | 225 | 186 | 56 | (104) | (184) | - | - | - | - |
| Harlem River 1 & 2[3] | 79.5 | (8.20) | 71.30 | 189 | 150 | 20 | (140) | (220) | - | - | - | - |
| Harlem River 1[3] | 39.9 | (4.12) | 35.78 | 224 | 186 | 56 | (104) | (184) | - | - | - | - |
| Harlem River 2[3] | 39.6 | (4.09) | 35.51 | 225 | 186 | 56 | (104) | (184) | - | - | - | - |
| Vernon Blvd 2 & 3[3] | 79.9 | (8.25) | 71.65 | 188 | 150 | 20 | (140) | (220) | - | - | - | - |
| Vernon Blvd 2[3] | 40.0 | (4.13) | 35.87 | 224 | 186 | 56 | (104) | (184) | - | - | - | - |
| Vernon Blvd 3[3] | 39.9 | (4.12) | 35.78 | 224 | 186 | 56 | (104) | (184) | - | - | - | - |
| Astoria CC 1 & 2 | 474.0 | (22.33) | 451.67 | (192) | (230) | (360) | (520) | (600) | (1,107) | (1,257) | (1,417) | (1,587) |
| Astoria CC 1 | 237.0 | (11.16) | 225.84 | 34 | (4) | (134) | (294) | (374) | (882) | (1,032) | (1,192) | (1,362) |
| Astoria CC 2 | 237.0 | (11.16) | 225.84 | 34 | (4) | (134) | (294) | (374) | (882) | (1,032) | (1,192) | (1,362) |
| Astoria East Energy CC1 & CC2 | 582.8 | (27.45) | 555.35 | (295) | (334) | (464) | (624) | (704) | (1,211) | (1,361) | (1,521) | (1,691) |
| Astoria East Energy - CC1 | 291.4 | (13.72) | 277.68 | (18) | (56) | (186) | (346) | (426) | (933) | (1,083) | (1,243) | (1,413) |
| Astoria East Energy - CC2 | 291.4 | (13.72) | 277.68 | (18) | (56) | (186) | (346) | (426) | (933) | (1,083) | (1,243) | (1,413) |

| New York City | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | Year | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 |
| New York City Transmission Security Margin, Summer Peak - Baseline Expected Summer Weather, Normal Transfer Criteria (MW) (1) | | | | 260 | 222 | 92 | (68) | (148) | (656) | (806) | (966) | (1,136) |
| Unit Name | Summer DMNC (MW) | NERC 5-Year Class Average De-Rate (MW) | Summer De-Rated Capability (MW) | Transmission Security Margin Considering Impact of Generator Outage (Retire, Mothball, IIFO) | | | | | | | | |
| Astoria Energy 2 - CC3 & CC4 | 570.3 | (26.86) | 543.44 | (283) | (322) | (452) | (612) | (692) | (1,199) | (1,349) | (1,509) | (1,679) |
| Astoria Energy 2 - CC3 | 285.0 | (13.42) | 271.58 | (11) | (50) | (180) | (340) | (420) | (927) | (1,077) | (1,237) | (1,407) |
| Astoria Energy 2 - CC4 | 285.3 | (13.44) | 271.86 | (12) | (50) | (180) | (340) | (420) | (928) | (1,078) | (1,238) | (1,408) |
| Bayonne EC CT G1 through G10 | 604.8 | (54.67) | 550.13 | (290) | (328) | (458) | (618) | (698) | (1,206) | (1,356) | (1,516) | (1,686) |
| Bayonne EC CTG1 | 62.0 | (5.60) | 56.40 | 204 | 165 | 35 | (125) | (205) | (712) | (862) | (1,022) | (1,192) |
| Bayonne EC CTG2 | 58.0 | (5.24) | 52.76 | 207 | 169 | 39 | (121) | (201) | (709) | (859) | (1,019) | (1,189) |
| Bayonne EC CTG3 | 58.1 | (5.25) | 52.85 | 207 | 169 | 39 | (121) | (201) | (709) | (859) | (1,019) | (1,189) |
| Bayonne EC CTG4 | 61.1 | (5.52) | 55.58 | 205 | 166 | 36 | (124) | (204) | (711) | (861) | (1,021) | (1,191) |
| Bayonne EC CTG5 | 61.8 | (5.59) | 56.21 | 204 | 165 | 35 | (125) | (205) | (712) | (862) | (1,022) | (1,192) |
| Bayonne EC CTG6 | 61.4 | (5.55) | 55.85 | 204 | 166 | 36 | (124) | (204) | (712) | (862) | (1,022) | (1,192) |
| Bayonne EC CTG7 | 59.7 | (5.40) | 54.30 | 206 | 167 | 37 | (123) | (203) | (710) | (860) | (1,020) | (1,190) |
| Bayonne EC CTG8 | 60.0 | (5.42) | 54.58 | 206 | 167 | 37 | (123) | (203) | (710) | (860) | (1,020) | (1,190) |
| Bayonne EC CTG9 | 61.3 | (5.54) | 55.76 | 204 | 166 | 36 | (124) | (204) | (712) | (862) | (1,022) | (1,192) |
| Bayonne EC CTG10 | 61.4 | (5.55) | 55.85 | 204 | 166 | 36 | (124) | (204) | (712) | (862) | (1,022) | (1,192) |

Notes

1. Utilizes the Higher Policy Transmission Security Margin for Summer Peak with Expected Weather.

2. In all years the most limiting contingency includes the loss of Ravenswood 3. For this calculation the margin based on the loss of two transmission elements is utilized. Other combinations with loss of generation may be more limiting.

3. Unit is modeled out of service beginning in 2031 in the baseline margin calculation.

**Figure 54: AOI - Long Island Transmission Security Margin**

| Long Island | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Year | | | | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 |
| Long Island Transmission Security Margin, Summer Peak - Baseline Expected Summer Weather, Normal Transfer Criteria (MW) (1) | | | | 318 | 22 | 119 | 101 | 1,996 | 1,880 | 1,811 | 1,752 | 1,657 |
| Unit Name | Summer DMNC (MW) | NERC 5-Year Class Average De-Rate (MW) | Summer De-Rated Capability (MW) | Transmission Security Margin Considering Impact of Generator Outage (Retire, Mothball, IIFO) | | | | | | | | |
| Greenport IC 4, 5, & 6 | 5.6 | (0.83) | 4.77 | 313 | 17 | 114 | 96 | 1,992 | 1,875 | 1,807 | 1,748 | 1,652 |
| Greenport IC 4 | 1.0 | (0.15) | 0.85 | 317 | 21 | 118 | 100 | 1,996 | 1,879 | 1,810 | 1,751 | 1,656 |
| Greenport IC 5 | 1.5 | (0.22) | 1.28 | 317 | 20 | 117 | 100 | 1,995 | 1,879 | 1,810 | 1,751 | 1,656 |
| Greenport IC 6 | 3.1 | (0.46) | 2.64 | 316 | 19 | 116 | 98 | 1,994 | 1,877 | 1,809 | 1,750 | 1,654 |
| Freeport 1-2, 1-3, & 2-3 | 19.2 | (2.21) | 16.99 | 301 | 5 | 102 | 84 | 1,979 | 1,863 | 1,794 | 1,735 | 1,640 |
| Freeport 1-2 | 2.3 | (0.34) | 1.96 | 316 | 20 | 117 | 99 | 1,994 | 1,878 | 1,809 | 1,750 | 1,655 |
| Freeport 1-3 | 2.7 | (0.40) | 2.30 | 316 | 19 | 116 | 99 | 1,994 | 1,878 | 1,809 | 1,750 | 1,654 |
| Freeport 2-3 | 14.2 | (1.47) | 12.73 | 306 | 9 | 106 | 88 | 1,984 | 1,867 | 1,799 | 1,740 | 1,644 |
| Charles P Killer 09 through 14 | 13.5 | (1.78) | 11.72 | 307 | 10 | 107 | 89 | 1,985 | 1,868 | 1,800 | 1,741 | 1,645 |
| Charles P Keller 09 | 1.6 | (0.21) | 1.39 | 317 | 20 | 117 | 100 | 1,995 | 1,878 | 1,810 | 1,751 | 1,655 |
| Charles P Keller 10 | 1.6 | (0.21) | 1.39 | 317 | 20 | 117 | 100 | 1,995 | 1,878 | 1,810 | 1,751 | 1,655 |
| Charles P Keller 11 | 2.4 | (0.32) | 2.08 | 316 | 20 | 116 | 99 | 1,994 | 1,878 | 1,809 | 1,750 | 1,655 |
| Charles P Keller 12 | 2.5 | (0.33) | 2.17 | 316 | 19 | 116 | 99 | 1,994 | 1,878 | 1,809 | 1,750 | 1,655 |
| Charles P Keller 13 | 2.5 | (0.33) | 2.17 | 316 | 19 | 116 | 99 | 1,994 | 1,878 | 1,809 | 1,750 | 1,655 |
| Charles P Keller 14 | 2.9 | (0.38) | 2.52 | 316 | 19 | 116 | 98 | 1,994 | 1,877 | 1,809 | 1,750 | 1,654 |
| Wading River 1, 2, & 3 | 214.8 | (22.17) | 192.63 | 126 | (171) | (74) | (92) | 1,804 | 1,687 | 1,619 | 1,560 | 1,464 |
| Wading River 1 | 77.6 | (8.01) | 69.59 | 249 | (48) | 49 | 31 | 1,927 | 1,810 | 1,742 | 1,683 | 1,587 |
| Wading River 2 | 64.3 | (6.64) | 57.66 | 261 | (36) | 61 | 43 | 1,939 | 1,822 | 1,754 | 1,695 | 1,599 |
| Wading River 3 | 72.9 | (7.52) | 65.38 | 253 | (44) | 53 | 36 | 1,931 | 1,814 | 1,746 | 1,687 | 1,591 |
| Barrett ST 01 & 02 | 380.5 | (41.28) | 339.22 | (21) | (318) | (221) | (238) | 1,657 | 1,541 | 1,472 | 1,413 | 1,318 |

| Long Island | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Year | | | | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 |
| Long Island Transmission Security Margin, Summer Peak - Baseline Expected Summer Weather, Normal Transfer Criteria (MW) (1) | | | | 318 | 22 | 119 | 101 | 1,996 | 1,880 | 1,811 | 1,752 | 1,657 |
| Unit Name | Summer DMNC (MW) | NERC 5-Year Class Average De-Rate (MW) | Summer De-Rated Capability (MW) | Transmission Security Margin Considering Impact of Generator Outage (Retire, Mothball, IIFO) | | | | | | | | |
| Barrett ST 01 | 192.0 | (20.83) | 171.17 | 147 | (150) | (53) | (70) | 1,825 | 1,709 | 1,640 | 1,581 | 1,486 |
| Barrett ST 02 | 188.5 | (20.45) | 168.05 | 150 | (146) | (50) | (67) | 1,828 | 1,712 | 1,643 | 1,584 | 1,489 |
| Barrett GT 01 through 12 | 246.6 | (23.47) | 223.13 | 95 | (201) | (105) | (122) | 1,773 | 1,657 | 1,588 | 1,529 | 1,434 |
| Barrett GT 01 | 13.7 | (1.41) | 12.29 | 306 | 9 | 106 | 89 | 1,984 | 1,868 | 1,799 | 1,740 | 1,644 |
| Barrett GT 02 | 13.6 | (1.40) | 12.20 | 306 | 9 | 106 | 89 | 1,984 | 1,868 | 1,799 | 1,740 | 1,645 |
| Barrett 03 | 12.2 | (1.26) | 10.94 | 307 | 11 | 108 | 90 | 1,985 | 1,869 | 1,800 | 1,741 | 1,646 |
| Barrett 04 | 14.5 | (1.50) | 13.00 | 305 | 9 | 106 | 88 | 1,983 | 1,867 | 1,798 | 1,739 | 1,644 |
| Barrett 05 | 12.0 | (1.24) | 10.76 | 307 | 11 | 108 | 90 | 1,986 | 1,869 | 1,801 | 1,742 | 1,646 |
| Barrett 06 | 12.9 | (1.33) | 11.57 | 307 | 10 | 107 | 89 | 1,985 | 1,868 | 1,800 | 1,741 | 1,645 |
| Barrett 08 | 12.8 | (1.32) | 11.48 | 307 | 10 | 107 | 89 | 1,985 | 1,868 | 1,800 | 1,741 | 1,645 |
| Barrett 09 | 38.6 | (3.49) | 35.11 | 283 | (13) | 83 | 66 | 1,961 | 1,845 | 1,776 | 1,717 | 1,622 |
| Barrett 10 | 39.2 | (3.54) | 35.66 | 283 | (14) | 83 | 65 | 1,961 | 1,844 | 1,776 | 1,717 | 1,621 |
| Barrett 11 | 38.2 | (3.45) | 34.75 | 283 | (13) | 84 | 66 | 1,962 | 1,845 | 1,777 | 1,718 | 1,622 |
| Barrett 12 | 38.9 | (3.52) | 35.38 | 283 | (14) | 83 | 66 | 1,961 | 1,844 | 1,776 | 1,717 | 1,621 |
| Northport 1, 2, 3, and 4 | 1,582.2 | (171.67) | 1,410.53 | (1,092) | (1,389) | (1,292) | (1,310) | 586 | 469 | 401 | 342 | 246 |
| Northport 1 | 399.0 | (43.29) | 355.71 | (37) | (334) | (237) | (255) | 1,641 | 1,524 | 1,456 | 1,397 | 1,301 |
| Northport 2 | 399.0 | (43.29) | 355.71 | (37) | (334) | (237) | (255) | 1,641 | 1,524 | 1,456 | 1,397 | 1,301 |
| Northport 3 | 386.2 | (41.90) | 344.30 | (26) | (323) | (226) | (243) | 1,652 | 1,536 | 1,467 | 1,408 | 1,312 |
| Northport 4 | 398.0 | (43.18) | 354.82 | (37) | (333) | (236) | (254) | 1,642 | 1,525 | 1,457 | 1,398 | 1,302 |

| Long Island | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Year | | | | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 |
| Long Island Transmission Security Margin, Summer Peak - Baseline Expected Summer Weather, Normal Transfer Criteria (MW) (1) | | | | 318 | 22 | 119 | 101 | 1,996 | 1,880 | 1,811 | 1,752 | 1,657 |
| Unit Name | Summer DMNC (MW) | NERC 5-Year Class Average De-Rate (MW) | Summer De-Rated Capability (MW) | Transmission Security Margin Considering Impact of Generator Outage (Retire, Mothball, IIFO) | | | | | | | | |
| Port Jefferson GT 02 & 03 | 79.3 | (8.18) | 71.12 | 247 | (49) | 47 | 30 | 1,925 | 1,809 | 1,740 | 1,681 | 1,586 |
| Port Jefferson GT 02 | 39.1 | (4.04) | 35.06 | 283 | (13) | 83 | 66 | 1,961 | 1,845 | 1,776 | 1,717 | 1,622 |
| Port Jefferson GT 03 | 40.2 | (4.15) | 36.05 | 282 | (14) | 82 | 65 | 1,960 | 1,844 | 1,775 | 1,716 | 1,621 |
| Port Jefferson 3 & 4 | 380.0 | (41.23) | 338.77 | (21) | (317) | (220) | (238) | 1,658 | 1,541 | 1,473 | 1,414 | 1,318 |
| Port Jefferson 3 | 191.0 | (20.72) | 170.28 | 148 | (149) | (52) | (69) | 1,826 | 1,710 | 1,641 | 1,582 | 1,487 |
| Port Jefferson 4 | 189.0 | (20.51) | 168.49 | 150 | (147) | (50) | (68) | 1,828 | 1,711 | 1,643 | 1,584 | 1,488 |
| Hempstead (RR) | 74.2 | (8.05) | 66.15 | 252 | (45) | 52 | 35 | 1,930 | 1,814 | 1,745 | 1,686 | 1,591 |
| Glenwood GT 02, 04, & 05 | 123.9 | (12.79) | 111.11 | 207 | (89) | 7 | (10) | 1,885 | 1,769 | 1,700 | 1,641 | 1,546 |
| Glenwood GT 02 | 40.3 | (4.16) | 36.14 | 282 | (14) | 82 | 65 | 1,960 | 1,844 | 1,775 | 1,716 | 1,621 |
| Glenwood GT 04 | 41.9 | (4.32) | 37.58 | 281 | (16) | 81 | 63 | 1,959 | 1,842 | 1,774 | 1,715 | 1,619 |
| Glenwood GT 05 | 41.7 | (4.30) | 37.40 | 281 | (16) | 81 | 64 | 1,959 | 1,842 | 1,774 | 1,715 | 1,619 |
| Holtsville 01 through 10 | 527.9 | (47.72) | 480.18 | (162) | (459) | (362) | (379) | 1,516 | 1,400 | 1,331 | 1,272 | 1,177 |
| Holtsville 01 | 54.2 | (4.90) | 49.30 | 269 | (28) | 69 | 52 | 1,947 | 1,831 | 1,762 | 1,703 | 1,607 |
| Holtsville 02 | 56.8 | (5.13) | 51.67 | 267 | (30) | 67 | 49 | 1,945 | 1,828 | 1,760 | 1,701 | 1,605 |
| Holtsville 03 | 51.2 | (4.63) | 46.57 | 272 | (25) | 72 | 54 | 1,950 | 1,833 | 1,765 | 1,706 | 1,610 |
| Holtsville 04 | 53.0 | (4.79) | 48.21 | 270 | (27) | 70 | 53 | 1,948 | 1,832 | 1,763 | 1,704 | 1,609 |
| Holtsville 05 | 52.6 | (4.76) | 47.84 | 270 | (26) | 71 | 53 | 1,949 | 1,832 | 1,763 | 1,704 | 1,609 |
| Holtsville 06 | 49.4 | (4.47) | 44.93 | 273 | (23) | 74 | 56 | 1,951 | 1,835 | 1,766 | 1,707 | 1,612 |
| Holtsville 07 | 54.0 | (4.88) | 49.12 | 269 | (27) | 69 | 52 | 1,947 | 1,831 | 1,762 | 1,703 | 1,608 |

| Long Island | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Year | | | | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 |
| Long Island Transmission Security Margin, Summer Peak - Baseline Expected Summer Weather, Normal Transfer Criteria (MW) (1) | | | | 318 | 22 | 119 | 101 | 1,996 | 1,880 | 1,811 | 1,752 | 1,657 |
| Unit Name | Summer DMNC (MW) | NERC 5-Year Class Average De-Rate (MW) | Summer De-Rated Capability (MW) | Transmission Security Margin Considering Impact of Generator Outage (Retire, Mothball, IIFO) | | | | | | | | |
| Holtsville 08 | 49.9 | (4.51) | 45.39 | 273 | (24) | 73 | 56 | 1,951 | 1,834 | 1,766 | 1,707 | 1,611 |
| Holtsville 09 | 55.4 | (5.01) | 50.39 | 268 | (29) | 68 | 51 | 1,946 | 1,829 | 1,761 | 1,702 | 1,606 |
| Holtsville 10 | 51.4 | (4.65) | 46.75 | 271 | (25) | 72 | 54 | 1,950 | 1,833 | 1,765 | 1,706 | 1,610 |
| Shoreham GT 3 & 4 | 84.7 | (8.74) | 75.96 | 242 | (54) | 43 | 25 | 1,920 | 1,804 | 1,735 | 1,676 | 1,581 |
| Shoreham GT3 | 42.9 | (4.43) | 38.47 | 280 | (17) | 80 | 62 | 1,958 | 1,841 | 1,773 | 1,714 | 1,618 |
| Shoreham GT4 | 41.8 | (4.31) | 37.49 | 281 | (16) | 81 | 63 | 1,959 | 1,842 | 1,774 | 1,715 | 1,619 |
| East Hampton GT 01, 2, 3, & 4 | 23.8 | (2.47) | 21.33 | 297 | 0 | 97 | 80 | 1,975 | 1,859 | 1,790 | 1,731 | 1,635 |
| East Hampton GT 01 | 18.4 | (1.66) | 16.74 | 301 | 5 | 102 | 84 | 1,980 | 1,863 | 1,795 | 1,736 | 1,640 |
| East Hampton 2 | 1.8 | (0.27) | 1.53 | 317 | 20 | 117 | 99 | 1,995 | 1,878 | 1,810 | 1,751 | 1,655 |
| East Hampton 3 | 1.8 | (0.27) | 1.53 | 317 | 20 | 117 | 99 | 1,995 | 1,878 | 1,810 | 1,751 | 1,655 |
| East Hampton 4 | 1.8 | (0.27) | 1.53 | 317 | 20 | 117 | 99 | 1,995 | 1,878 | 1,810 | 1,751 | 1,655 |
| Southold 1 | 9.5 | (0.98) | 8.52 | 310 | 13 | 110 | 92 | 1,988 | 1,871 | 1,803 | 1,744 | 1,648 |
| S Hampton 1 | 8.1 | (0.84) | 7.26 | 311 | 14 | 111 | 94 | 1,989 | 1,873 | 1,804 | 1,745 | 1,650 |
| Freeport CT 1 & 2 | 88.8 | (9.16) | 79.64 | 239 | (58) | 39 | 21 | 1,917 | 1,800 | 1,732 | 1,673 | 1,577 |
| Freeport CT 1 | 45.8 | (4.73) | 41.07 | 277 | (19) | 77 | 60 | 1,955 | 1,839 | 1,770 | 1,711 | 1,616 |
| Freeport CT 2 | 43.0 | (4.44) | 38.56 | 280 | (17) | 80 | 62 | 1,958 | 1,841 | 1,773 | 1,714 | 1,618 |
| Flynn | 139.5 | (6.57) | 132.93 | 185 | (111) | (14) | (32) | 1,863 | 1,747 | 1,678 | 1,619 | 1,524 |
| Greenport GT1 | 51.0 | (4.61) | 46.39 | 272 | (25) | 72 | 55 | 1,950 | 1,833 | 1,765 | 1,706 | 1,610 |
| Far Rockaway GT1 & GT2[2] | - | - | - | - | - | - | - | - | - | - | - | - |
| Far Rockaway GT1[2] | - | - | - | - | - | - | - | - | - | - | - | - |
| Far Rockaway GT2[2] | - | - | - | - | - | - | - | - | - | - | - | - |

| Long Island | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Year | | | | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 |
| Long Island Transmission Security Margin, Summer Peak - Baseline Expected Summer Weather, Normal Transfer Criteria (MW) (1) | | | | 318 | 22 | 119 | 101 | 1,996 | 1,880 | 1,811 | 1,752 | 1,657 |
| Unit Name | Summer DMNC (MW) | NERC 5-Year Class Average De-Rate (MW) | Summer De-Rated Capability (MW) | Transmission Security Margin Considering Impact of Generator Outage (Retire, Mothball, IIFO) | | | | | | | | |
| Bethpage | 51.0 | (2.40) | 48.60 | 270 | (27) | 70 | 52 | 1,948 | 1,831 | 1,763 | 1,704 | 1,608 |
| Bethpage 3 | 75.7 | (3.57) | 72.13 | 246 | (50) | 46 | 29 | 1,924 | 1,808 | 1,739 | 1,680 | 1,585 |
| Bethpage GT4 | 43.7 | (4.51) | 39.19 | 279 | (18) | 79 | 62 | 1,957 | 1,841 | 1,772 | 1,713 | 1,618 |
| Stony Brook (BTM:NG) | 0.0 | 0.00 | 0.00 | 318 | 22 | 119 | 101 | 1,996 | 1,880 | 1,811 | 1,752 | 1,657 |
| Brentwood | 45.0 | (4.64) | 40.36 | 278 | (19) | 78 | 61 | 1,956 | 1,840 | 1,771 | 1,712 | 1,616 |
| Pilgrim GT1 & GT2 | 83.6 | (8.63) | 74.97 | 243 | (53) | 44 | 26 | 1,921 | 1,805 | 1,736 | 1,677 | 1,582 |
| Pilgrim GT1 | 41.3 | (4.26) | 37.04 | 281 | (15) | 81 | 64 | 1,959 | 1,843 | 1,774 | 1,715 | 1,620 |
| Pilgrim GT2 | 42.3 | (4.37) | 37.93 | 280 | (16) | 81 | 63 | 1,958 | 1,842 | 1,773 | 1,714 | 1,619 |
| Pinelawn Power 1[2] | - | - | - | - | - | - | - | - | - | - | - | - |
| Caithness_CC_1 | 313.5 | (14.77) | 298.73 | 20 | (277) | (180) | (198) | 1,698 | 1,581 | 1,513 | 1,454 | 1,358 |
| Islip (RR) | 8.0 | (0.87) | 7.13 | 311 | 15 | 111 | 94 | 1,989 | 1,873 | 1,804 | 1,745 | 1,650 |
| Babylon (RR) | 15.7 | (1.70) | 14.00 | 304 | 8 | 105 | 87 | 1,982 | 1,866 | 1,797 | 1,738 | 1,643 |
| Huntington (RR) | 24.8 | (2.69) | 22.11 | 296 | (0) | 96 | 79 | 1,974 | 1,858 | 1,789 | 1,730 | 1,635 |

Notes

1. Utilizes the Higher Policy Transmission Security Margin for Summer Peak with Expected Weather.
2. Unit is modeled out of service beginning in 2026 in the baseline margin calculation.