

Short-Term Assessment of Reliability: 2026 Quarter 3

A Report by the
New York Independent System Operator

October 13, 2026

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Executive Summary

This report sets forth the 2026 Quarter 3 Short-Term Assessment of Reliability (“STAR”) findings for the five-year study period of July 15, 2026, through July 15, 2031, considering forecasts of peak power demand, planned upgrades to the transmission system, and changes to the generation mix over the next five years. The retirement of ADK Resource Recovery (Zone F, 14.4 MW nameplate) as an Initiating Generator¹ is evaluated in this STAR. There are no Generator Deactivation Reliability Needs identified by either the NYISO or National Grid associated with the retirement of ADK Resource Recovery.

Following the start of this STAR, the NYISO notified stakeholders on October 2, 2026 that Champlain Hudson Power Express (“CHPE”), which entered commercial operation on May 13, 2026, had demonstrated its planned capability. As a result, the Lower Hudson Valley Near-Term Reliability Need identified in the 2026 Quarter 1 and Quarter 2 STARs is no longer observed in this STAR, and the solution solicitation issued on August 20, 2026 is withdrawn. Accordingly, the NYISO will not proceed with the evaluation or selection of solutions submitted in response to the August 20, 2026 solicitation. With CHPE having demonstrated its planned capability, Danskammer 1-4 may enter a Mothball Outage² and the associated Interim Service Provider rate will terminate after the NYISO provides at least 60 days prior notice to Danskammer.

The Short-Term Reliability Process applies only to the first five years of the planning horizon through summer 2031. This STAR finds that the resource adequacy and transmission security reliability margins are sufficient through this timeframe, but remain narrow. Consequently, additional generator deactivations, reductions in available imports, higher-than-forecast demand, or other adverse system changes could result in new reliability needs being identified in future STAR assessments. Reliability conditions beyond this period of this STAR are examined in the 2026 Reliability Needs Assessment (RNA). The draft 2026 RNA results identify three Reliability Needs: a statewide resource deficiency beginning in 2033, a transmission-constrained deficiency in New

¹ Per Section 38.1 of the OATT, 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 Danskammer Energy, LLC’s Generator Deactivation Notice requested an evaluation to become Retired. Danskammer Energy, LLC later requested to change its notice to enter a Mothball Outage. The NYISO determined that the change would not impact the NYISO’s evaluation and is allowing Danskammer 1-4 to enter Mothball Outage. The associated Interim Service Provider rate will terminate after the NYISO provides at least 60 days prior notice to Danskammer. Danskammer Energy, LLC must complete all required NYISO administrative process and procedures prior to the deactivation of its generating units. See NYISO Technical Bulletin 185. The NYISO’s determination in this Short-Term Reliability Process does not relieve Danskammer Energy, LLC of any obligations they have with respect to its Generators participation in the NYISO markets. If Danskammer Energy, LLC rescinds its Generator Deactivation Notice or does not place Danskammer 1-4 in a Mothball Outage within 730 days of January 15, 2026 then it will be required to submit a new Generator Deactivation Notice in order to deactivate the affected Generator(s) and will be required to repay study cost in accordance with Section 38.14 of the OATT.

York City beginning in 2032, and a related need in the Lower Hudson Valley also beginning in 2032. Taken together, the findings indicate that maintaining a reliable grid will require at least 1,850 MW of new generation resources appropriately located with the necessary operating characteristics and coupled with transmission capability necessary to deliver those resources. In-state transmission alone will not resolve the statewide need.

Stability analysis performed in this STAR as well as the 2026 RNA indicates that the Fitzpatrick nuclear generating unit may lose synchronism following a fault at the Scriba 345 kV station under very light load conditions. This stability issue is projected to emerge as early as spring 2027 and persist throughout the reliability planning horizon. The NYISO has identified potential interim operating measures and will continue evaluating the issue through future STAR assessments.

Since the 2025 Quarter 3 STAR, the quarterly reports have observed the potential for supply deficiencies without the completion and energization of planned projects to address the deficiencies. For years, the NYISO's reliability planning reports have indicated that several related risk factors continue to shape near-term and long-term reliability conditions in New York. The advancing age of the existing generation fleet, growing electricity demand from electrification and large loads, and limited development of new dispatchable resources are narrowing planning and operating margins. These trends are amplified by reliance on imports that may not be available during regional peak events, increasing exposure to extreme weather, and uncertainty around the timing of major transmission and generation projects. As a result, maintaining reliability increasingly depends on careful management of interim conditions while permanent solutions advance.

Operational experience from the Summer 2025 heatwaves, as well as the heatwave experienced in early July 2026, revealed how quickly tight resource margins and limited system flexibility can lead to stressed conditions even when overall resource adequacy and projected capacity margins appear sufficient. Current criteria measure resource adequacy only after assuming the full utilization of emergency operating procedures, effectively planning for operations to rely on extraordinary measures as routine practice. This approach leaves fewer tools available when real-time conditions deteriorate. Further, during the early July 2026 heatwave, the grid experienced about two-to-three times the generator outages in the New York City and Lower Hudson Valley regions compared to what is currently planned for, along with several transmission outages. The coincident outages left the grid well outside established planning criteria and practices.

The continued safe operation of New York's electric grid depends on replacing an aging fossil

generation fleet that is approaching the limits of its useful life. These units were not designed to operate indefinitely, and their increasing failure risk places added strain on the system. As demand grows and older plants retire, new or repowered resources with the necessary set of reliability attributes must be developed to take their place. Delaying replacement increases reliance on emergency measures and reduces system flexibility. Proactive development of new or repowered replacement dispatchable resources is necessary for maintaining reliable electric service.

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")³ on Bulk Power Transmission Facilities ("BPTF") 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."⁴ 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 2026 Quarter 3 findings for the study period from the STAR Start Date (July 15, 2026) through July 15, 2031. 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.⁵

³ OATT Section 38.1 contains the tariff definition of a "Short-Term Reliability Process Need."

⁴ OATT Section 38.1 contains the tariff definition of a "Near-Term Reliability Need." See also, OATT Section 38.3.6.

⁵ For this STAR the NYISO utilized the Reliability Planning Process Manual, published June 1, 2026.

Assumptions

The NYISO evaluated the study period using the most recent Reliability Planning Process assumptions and data available as of July 14, 2026 (*i.e.*, the day before the July 15, 2026 Q3 STAR Start Date). In accordance with the Reliability Planning Process inclusion rules,⁶ generation and transmission projects are included if they have met significant milestones such that there is a 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 2026 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 August 3, 2026. The meeting materials are posted on the NYISO’s website.⁷

Generation Assumptions

Study assumptions of generators for this STAR are derived from the 2026 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 1. 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.⁸

⁶ See NYISO Reliability Planning Process Manual Section 3.

⁷ Short-Term Assessment of Reliability: 2026 Q3 Key Study Assumptions, ESPWG/TPAS, August 3, 2026 ([here](#))

⁸ See <https://www.nyiso.com/short-term-reliability-process> then Generator Deactivation Notices/Planned Retirement Notices or Generator Deactivation Notices/IIFO Notifications.

Figure 1: 2026 Quarter 3 STAR Generator Deactivations

Owner/ Operator	Plant Name	PTID	Zone	Nameplate (MW)	Status	Proposed Deactivation/IIFO Date
Wheelabrator Hudson Falls LLC	ADK RESOURCE RCVRY	23798	F	14.4	R	12/31/2026

Generator Return-to-Service

There are no generators that have returned to service following the 2026 RNA.

Generator Additions

There are generation additions beyond those included in the 2026 RNA. A list of generator additions, including updates to planned commercial operation dates compared to the 2026 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 and the subsequent preliminary injunctions to stay the suspension orders while the court considers the merits of the orders.

Additional Generation Assumptions

Consistent with the 2026 RNA, this STAR assumes the NYPA small gas plants listed in the 2026 Gold Book Table IV-6 (517 MW in Zones J and K) are out-of-service starting January 2031.

Demand Assumptions

This assessment primarily utilizes the demand forecasts from the 2026 Gold Book.

The NYISO 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. The 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 forecasts. The behind-the-meter (BTM) solar, BTM distributed generation, and energy storage forecasts are consistent across all three demand forecasts. 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. 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 (or partial 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.

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

Large Load Assumptions

Due to projected economic development over the next two decades, numerous new large loads are expected to interconnect to the New York system. These large loads are primarily proposed and expected to be concentrated in upstate New York. Most of these new loads consist of manufacturing facilities and data centers, including, for example, semiconductor fabrication, artificial intelligence, cryptocurrency mining, and data storage/cloud computing. The large load assumptions in this assessment are consistent with the 2026 RNA. By 2031 there are 1,593 MW of computational and 396 MW of industrial large loads.

On June 18, 2026, the Federal Energy Regulatory Commission (FERC) issued a show cause order to the NYISO and FERC-jurisdictional Transmission Owners related to large and co-located load integration.⁹ The NYISO has been working with stakeholders to develop reforms in response to FERC's order. For future planning cycles, the nature and impact of the large load trend in New York on the demand forecasts could change in response to such reforms.

Transmission Assumptions

Existing Transmission

The transmission assumptions utilized in this assessment are similar to those used for the 2026 RNA. Figure 2 lists the existing transmission outage assumptions.

Figure 2: Transmission Outage Assumptions

From	To	kV	ID	Out-of-Service Through	
				Prior STAR	This STAR
Marion	Farragut	345	B3402	Long-Term	
Marion	Farragut	345	C3403	Long-Term	
Plattsburgh (1)	Plattsburgh	230/115	AT1	9/2026	5/2027
Station 23	Station 42	115	920	12/2026	5/2027
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 2026 Gold Book.

On May 13, 2026, Champlain Hudson Power Express ("CHPE") entered commercial operation.

⁹ *New York Indep. Sys. Operator, Inc., et al.*, 195 FERC ¶ 61,216 (2026).

Following the start of this Quarter 3 STAR, the NYISO determined that CHPE had demonstrated its planned power capability.¹⁰ In addition, following the start of this STAR, the Office of the State Comptroller approved purchase agreements entered into by Long Island Power Authority through April 2032, affecting the anticipated Cross-Sound Cable MW schedule.

Compared to the 2026 RNA, there are no changes to assumed firm transmission facilities, as captured in Section 7 of the 2026 Gold Book. Details of the proposed transmission assumptions included in the 2026 RNA are provided in Appendix C. Except for the projects listed in Figure 25 in Appendix C, all firm transmission plans captured in the 2026 Gold Book are included.

¹⁰ Update Regarding the Lower Hudson Valley Near-Term Reliability Need and Associated Solution Solicitation, October 2, 2026 ([here](#))

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 the NYISO has determined that CHPE, which entered commercial operation on May 13, 2026, has demonstrated its planned capability. As a result, the Lower Hudson Valley Near-Term Reliability Need identified in the 2026 Quarter 1 and Quarter 2 STARs is no longer observed, the solution solicitation issued on August 20, 2026 is hereby withdrawn, and Danskammer 1-4 may enter Mothball Outage¹¹ and the associated Interim Service Provider rate will terminate after the NYISO provides at least 60 days prior notice to Danskammer, consistent with Section 38.13.2.4. of the OATT.

Even with the operation of CHPE and the continued operation of the Gowanus 2 & 3 and Narrows 1 & 2 barges until May of 2029,¹² the NYISO continues to observe narrow margins within New York City and on Long Island throughout the STAR time horizon. Just beyond the time horizon of this STAR, the margins in New York City and the Lower Hudson Valley are expected to be impacted by the deactivation of the NYPA Small Plants. As found in the 2026 RNA, the New York City locality is deficient just beyond the time horizon of this STAR. In summer 2032, New York City is deficient by approximately 400 MW for seven hours, with the deficiency worsening to approximately 1,850 MW for fifteen consecutive hours during the peak demand day in summer 2036. The Lower Hudson Valley is deficient by approximately 130 MW for two hours in summer 2032, increasing to approximately 1,950 MW for seven consecutive hours during the peak demand day in summer 2036.

¹¹Danskammer Energy, LLC's Generator Deactivation Notice requested an evaluation to become Retired. Danskammer Energy, LLC later requested to change its notice to enter a Mothball Outage. The NYISO determined that the change would not impact the NYISO's evaluation and is allowing Danskammer 1-4 to enter Mothball Outage. The associated Interim Service Provider rate will terminate after the NYISO provides at least 60 days prior notice to Danskammer. Danskammer Energy, LLC must complete all required NYISO administrative process and procedures prior to the deactivation of its generating units. See NYISO Technical Bulletin 185. The NYISO's determination in this Short-Term Reliability Process does not relieve Danskammer Energy, LLC of any obligations they have with respect to its Generators participation in the NYISO markets. If Danskammer Energy, LLC rescinds its Generator Deactivation Notice or does not place Danskammer 1-4 in a Mothball Outage within 730 days of January 15, 2026 then it will be required to submit a new Generator Deactivation Notice in order to deactivate the affected Generator(s) and will be required to repay study cost in accordance with Section 38.14 of the OATT.

¹² On April 15, 2026 the NYISO issued a letter to the DEC designating the Gowanus 2 & 3 and Narrows 1 & 2 generators as needed to address ongoing reliability needs until May 1, 2029. Extending these generators through May 1, 2029 helps alleviate the identified deficiencies, but without additional supply resources, reliability needs will likely develop at the end of the five-year horizon or shortly after it. Subsequently, on April 16, 2026, AlphaGen withdrew its generator deactivation notice for these units.

Following the approval of contracts affecting the expected Cross-Sound Cable MW import schedule, the margins on Long Island improve in the near-term horizon, but remain narrow until the Propel NY Energy transmission project is in service.

The NYISO observes no BPTF Generator Deactivation Reliability Needs with the proposed retirement of ADK Resource Recovery. Additionally, National Grid did not observe any local Generator Deactivation Reliability Needs with the retirement of this generator.

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"¹³ 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.¹⁴

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 power flow simulations combined with post-processing spreadsheet-based calculations. For the transmission security margin assessment, margins are evaluated for the Lower Hudson Valley, New York City, and Long Island localities. This evaluation will identify a BPTF reliability need 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.

For the purposes of identifying reliability needs on the BPTF using transmission security margin calculations, thermal generation MW capability is considered available based on NYCA zonal average EFORD.¹⁵ Derates for thermal generation are included due to the aging fleet without expected replacement, while the share of intermittent, weather dependent generation is growing.

Steady State Assessment

Beginning with the 2025 Quarter 3 STAR, the NYISO has been reporting thermal overloads on an Oakdale 345/115/34.5 kV transformer as well as the Oakdale – North Endicott 115 kV transmission line as early as summer 2026 that worsen over time. As such, this deficiency would be a Near-Term Reliability Need. However, NYSEG has a LTP to address these thermal overloads which is currently planned to be in service by summer 2031. The NYISO has confirmed with NYSEG that this LTP is making reasonable progress toward entering service by the projected in-service

¹³Attachment I of Transmission, Expansion, and Interconnection Manual.

¹⁴The RNA assumptions matrix is posted with the April 18, 2024 TPAS/ESPPWG meeting materials, which are available [here](#).

¹⁵Recent updates to the Reliability Planning Process Manual, including revisions to the thermal unit derating factor, were approved by Stakeholders at the May 14, 2026 Operating Committee ([here](#)). The revisions documented in the Reliability Planning Process Manual were reflected in the 2026 RNA as well as starting with this 2026 Quarter 3 STAR.

date. 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 LTPs, 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.

Figure 3: Needs Resolved by Local Transmission Plans

Need	LTP	Owner	Station	Description	In-Service Date	Notes
Oakdale Thermal Violations	Oakdale Rebuild	NYSEG	Oakdale 345 & Oakdale 115	Rebuild	Summer 2031	Expand existing 345 kV bus to 3 bay BAAH. Complete rebuild of 115 kV to 6 bay BAAH.

Dynamics Assessment

No stability criteria violations are observed under summer peak or winter peak cases. However, stability issues were identified primarily in the light load cases.

Stability analysis indicates that the Fitzpatrick nuclear generator can lose synchronism for a fault at Scriba 345kV resulting in loss of Scriba – Volney 345 kV (Line 21) and Scriba – Fitzpatrick 345 kV (FS-10) lines. This issue is observed most prominently in spring midday time light load conditions with high solar and BtM generation output; however, this issue is also observed in nighttime light load conditions. This stability issue may emerge as early as spring 2027 and persists throughout the RNA study horizon.

To address this issue, in the operations horizon the NYISO will rely on potential interim operating measures to maintain system reliability. As the full nature of this issue is still being evaluated, the NYISO will continue to evaluate this in future STAR assessments.

Short Circuit Assessment

No BPTF short-circuit criteria violations were observed in this assessment.

Transmission Security Margin Assessment

For the transmission security margin assessment, the NYISO evaluates 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).

For generator deactivations the NYISO evaluates a broader range of key assumptions to manage uncertainty. In evaluating the planned system, Generator Deactivation Assessments also identify

any dependencies on future planned projects (a.k.a “status quo”). Should a dependency be identified on a future planned project, the NYISO may identify a Generator Deactivation Reliability Need.

Lower Hudson Valley Transmission Security Margin

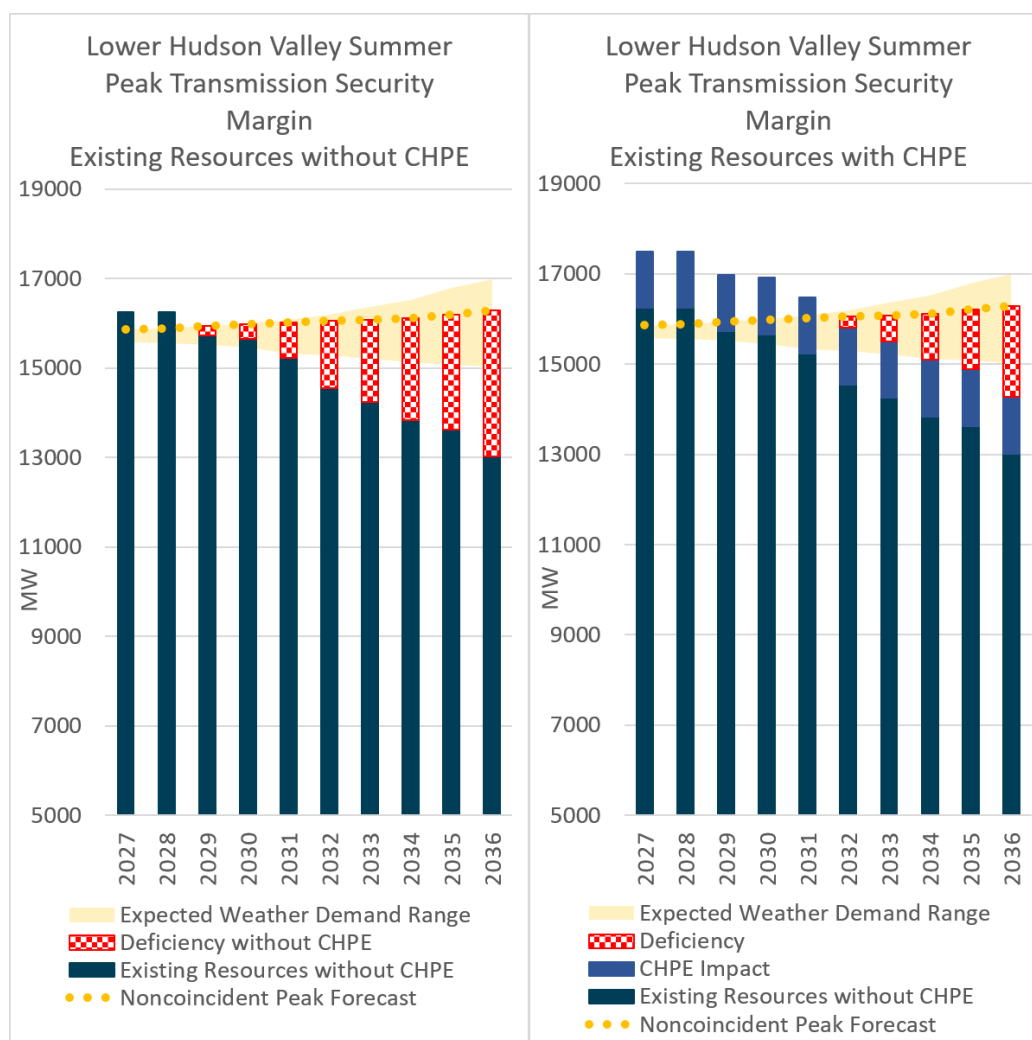
Consistent with the findings of the 2025 Quarter 3 and Quarter 4 STARs, the 2026 Quarter 1 STAR identified a Generator Deactivation Reliability Need in the Lower Hudson Valley locality that was primarily driven by transmission security deficiencies in New York City and Long Island and exacerbated by the proposed Mothball Outage of Danskammer Units 1-4. The 2026 Quarter 2 STAR reaffirmed this need, finding that deficiencies would continue to be observed in summer 2029 and summer 2030 until planned projects entered service and demonstrated their planned capabilities. On May 13, 2026, CHPE entered commercial operation; however, in the 2026 Quarter 2 STAR because CHPE had not yet demonstrated its planned power capability, the Lower Hudson Valley Near-Term Reliability Need remained and the NYISO issued a solution solicitation on August 20, 2026 to address the identified reliability need.¹⁶

The impact of CHPE demonstrating its planned power capability under status quo conditions is shown in Figure 4. In the status quo condition, the Lower Hudson Valley Near-Term Reliability Need is no longer observed and the margin is sufficient throughout the time horizon of this STAR. As such, in accordance with Section 38.4.8 of the OATT, as the scope, scale or nature of the need has changed such that it is now resolved, the NYISO hereby withdraws the August 20, 2026 solution solicitation. With CHPE having demonstrated its planned capability, Danskammer 1-4 may enter Mothball Outage¹⁷ and the associated Interim Service Provider rate will terminate after the NYISO provides at least 60 days prior notice to Danskammer, consistent with Section 38.13.2.4. of the OATT.

¹⁶ Section 8 of the Reliability Planning Process Manual provides that, as part of Generator Deactivation Assessments, NYISO evaluates a broader range of key assumptions to manage uncertainty, including dependencies on future planned projects (a.k.a “status quo”). Should a dependency be identified on a future planned project the NYISO may identify a Generator Deactivation Reliability Need.

¹⁷ Danskammer Energy, LLC’s Generator Deactivation Notice requested an evaluation to become Retired. Danskammer Energy, LLC later requested to change its notice to enter a Mothball Outage. The NYISO determined that the change would not impact the NYISO’s evaluation and is allowing Danskammer 1-4 to enter Mothball Outage. The associated Interim Service Provider rate will terminate after the NYISO provides at least 60 days prior notice to Danskammer. Danskammer Energy, LLC must complete all required NYISO administrative process and procedures prior to the deactivation of its generating units. See NYISO Technical Bulletin 185. The NYISO’s determination in this Short-Term Reliability Process does not relieve Danskammer Energy, LLC of any obligations they have with respect to its Generators participation in the NYISO markets. If Danskammer Energy, LLC rescinds its Generator Deactivation Notice or does not place Danskammer 1-4 in a Mothball Outage within 730 days of January 15, 2026 then it will be required to submit a new Generator Deactivation Notice in order to deactivate the affected Generator(s) and will be required to repay study cost in accordance with Section 38.14 of the OATT.

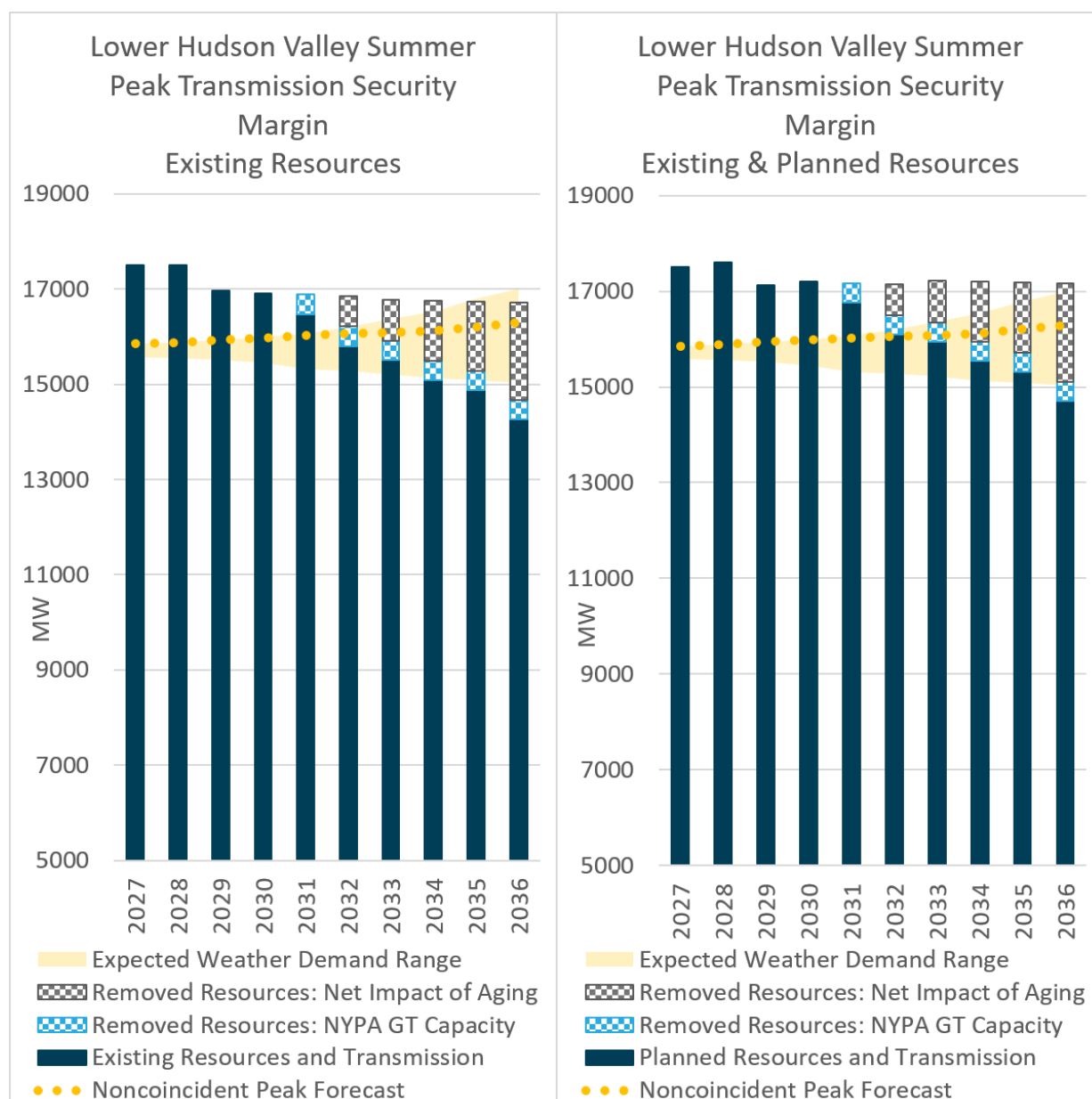
Figure 4: Impact of CHPE on Lower Hudson Valley Status Quo Transmission Security Margin



Under the planned conditions shown in Figure 5, the margins shown to be are sufficient in the time horizon of this STAR. However, the margin in this locality is deficient just beyond the time horizon of this STAR. Starting in 2033, the margin is deficient by 140 MW over 2 hours worsening to nearly 1,600 MW over 7 hours in 2036. The availability of the NYPA small gas plants (or equivalent replacements) would push out the need by a year and decrease the size of the need in 2036 by approximately 400 MW.

Winter peak transmission security margins for the Lower Hudson Valley are sufficient in all planning years.

Figure 5: Lower Hudson Valley Transmission Security Margin



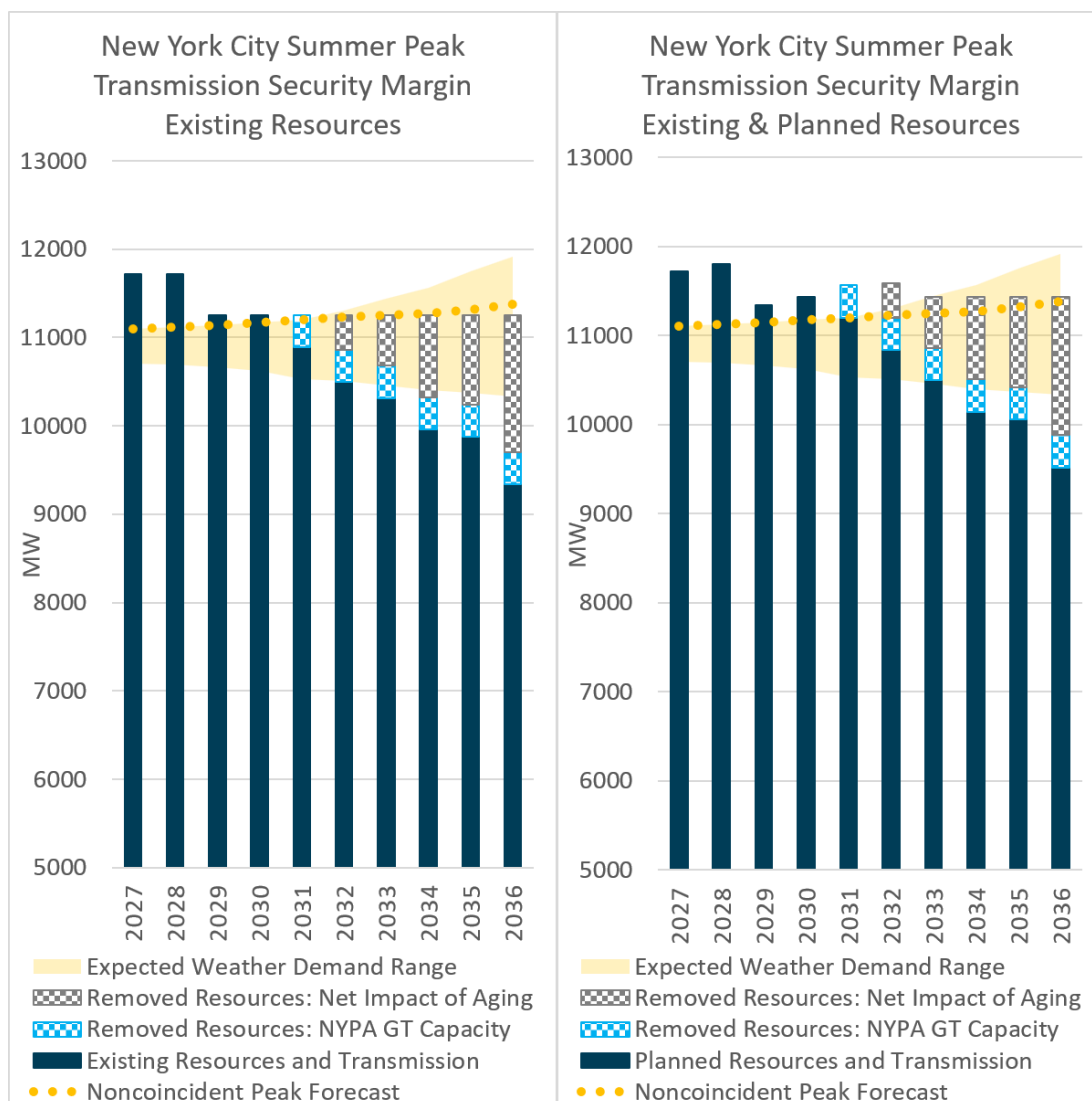
New York City Transmission Security Margin

The planned summer peak transmission security margin results for New York City are shown in Figure 6. The margin is sufficient throughout the time horizon of this STAR with CHPE having demonstrated its planned capability.

Just beyond the time horizon of this STAR, the margin in this locality is deficient starting in 2032 by nearly 400 MW for 7 hours, worsening to a total deficiency of just over 1,850 MW for 15 hours in 2036. If battery energy storage resources are not available for discharge, Zone J would be

deficient earlier by about 130 MW for 3 hours in 2031. These deficiencies are driven primarily by the assumed unavailability of the NYPA small plants and aging generation risk. The availability of the NYPA small gas plants (or equivalent replacements) would push out the need by a year and decrease the size of the need in 2036 by approximately 350 MW.

Figure 6: New York City Transmission Security Margin



In December 2025, the New York State Public Service Commission directed Con Edison to develop a “NYC Reliability Contingency Plan” and to file a report identifying the specific reliability needs that Con Edison sees arising in its service territory, the dates of those needs, and the

underlying assumptions and methodologies used in determining those needs.¹⁸ In December 2025, the preliminary assessment identified a deficiency within the New York City 345/138 kV Transmission Load Area (“TLA”) of 250 MW over 4 hours (about 700 MWh). In January 2026, Con Edison updated these findings and is now projecting a deficiency to begin in 2032 at 125 MW. Con Edison updated its 2025 LTP at the March 20, 2026 ESPWG/TPAS meeting based on the findings under this proceeding.¹⁹

Long Island Transmission Security Margin

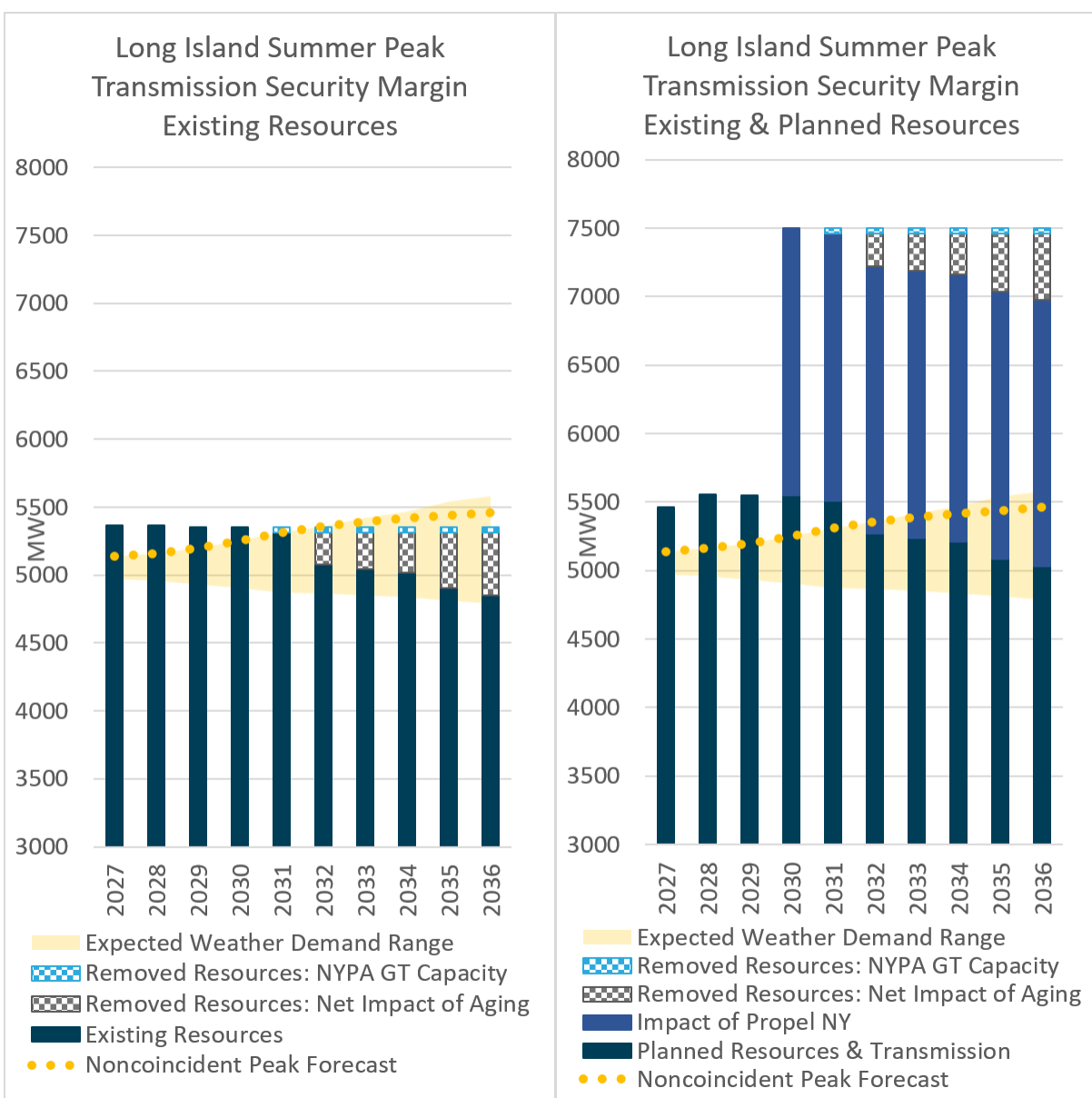
Summer peak transmission security margin results are shown in Figure 7. The margin is sufficient throughout the time horizon of this STAR.

Following the start of this STAR, the Office of the State Comptroller approved three capacity purchase agreements between the Long Island Power Authority the Long Island Power Authority and, respectively, Salem Harbor Power Development, LP; Millennium Power Company, LLC; and Berkshire Power Company, LLC. These agreements extend through April 2032 and affect the anticipated Cross-Sound Cable MW schedule. The increased resources supplying power into Long Island significantly improved the margins in the near-term; however, they do remain comparatively narrow in the near-term until the Propel NY Energy transmission project enters service.

¹⁸ Details on the Con Edison Reliability Needs Report and subsequent Request for Information for clean and non-emitting reliability solutions to manage peak demand and address the transmission security need within NYCA Zone J (as observed by Con Edison) is found on the Con Edison website ([here](#)).

¹⁹ Con Edison’s LTP update was presented to NYISO stakeholders at the March 20, 2026 ESPWG/TPAS meeting ([here](#))

Figure 7: Long Island Transmission Security Margin



Local Non-BPTF Reliability Assessment

National Grid evaluated the impact of the ADK Resource Recovery retirement on its non-BPTF and did not identify any Generator Deactivation Reliability Needs. The NYISO reviewed and verified the analysis performed by National Grid.

Solutions to Previously Identified Short-Term Reliability Needs

On January 9, 2026, the NYISO received proposed solutions to the 2025 Quarter 3 STAR needs within New York City and Long Island. In the Short-Term Reliability Process Report issued on April 15, 2026, the NYISO discussed the solutions submitted by Developers that it selected and other planned projects that meet the reliability planning process inclusion rules that help address reliability.²⁰ The NYISO continues to track the solutions shown in Figure 8 and Figure 9.

While all 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.

New York City

In 2023, the NYISO previously determined that temporarily retaining the generators on the Gowanus 2 & 3 and Narrows 1 & 2 barges was necessary to address ongoing reliability needs, and the NYISO's designation of these generators allows their continued operation until May 1, 2027 or until permanent solutions are in place. Reliability needs due to supply deficiencies, continue to require Gowanus 2 & 3 and Narrows 1 & 2 barges to be available and to operate. Without the retention of these generators, the New York City and Lower Hudson Valley areas would be deficient during expected summer weather peak demand periods.

In the April 15, 2026 Short-Term Reliability Process Report, the NYISO most recently designated the Gowanus 2 & 3 and Narrows 1 & 2 generators (608 MW nameplate)²¹ as needed to address ongoing reliability needs until May 1, 2029, the maximum permissible permit extension date allowed, or until reliability needs are no longer identified in the NYISO's reliability assessments. AlphaGen, the owner, withdrew the generator deactivation notice for these generators on April 16, 2026. On May 13, 2026, CHPE entered commercial operation. As explained above, the NYISO has determined that CHPE demonstrated its planned capability, so CHPE is now included in the NYISO's status-quo assessments.

²⁰ See NYISO.com, Planning, Short-Term Reliability Process, Short-Term Reliability Process Solutions, Short-Term Reliability Process Report

²¹ The total nameplate MW capability of the Gowanus and Narrows barges is 672 MW. However, on April 1, 2025, Gowanus 3-6 entered IFO and on May 1, 2025 Narrows 2-1 and 2-7 entered IFO reducing the capability of these barges to 608 MW nameplate.

Figure 8: Projects Identified to Address New York City Need

Projects to Identified to Address New York City Need					
	Queue Pos.	Proposed Solution Developer	Project Name	Nameplate (MW)	Proposed In-Service
Proposed Solution	N/A	AlphaGen	Existing Gowanus & Narrows Retention	608	Existing
	Queue Pos.	Developer/Interconnection Customer	Project Name	Nameplate (MW)	Proposed In-Service
Other Projects (Permanent Solutions)	631/887	CHPE LLC	NS Power Express	1,250	In-Service
	0827	Lighthouse Arthur Kill, LLC	Arthur Kill Energy Storage 1	15	Winter 2026
	0931	East River ESS, LLC	Astoria Energy Storage	100	Winter 2026
	0737	Empire Offshore Wind LLC	Empire Wind 1	816	Winter 2027
	1289	New York Power Authority / New York Transco LLC.	Propel NY Energy - Alternate Solution 5	-	Summer 2030

Long Island

To address the bulk system need in Long Island the NYISO selected the PSEG-LI generation solution. The Far Rockaway, Glenwood, and Shoreham generation solutions together address the near-term deficiencies, but there would be less than 100 MW of margin prior to the Propel NY transmission project entering service. The solutions for the non-bulk system need are the Far Rockaway 2 unit and local transmission upgrades that went into service in December 2025.

Figure 9: Projects Identified to Address Long Island BPTF Need

Projects to Identified to Address Long Island Need					
	Queue Pos.	Proposed Solution Developer	Project Name	Nameplate (MW)	Proposed In-Service
Proposed Solutions	N/A	PSEG-LI/LIPA	Shoreham 1 (water injection)	52.9	Existing, water injection by May 1, 2027
			Shoreham 2 (water injection)	18.6	
			Glenwood GT 3 (water injection)	55	
			Far Rockaway 1	60.5	Existing
			Far Rockaway 2	60.5	
	Queue Pos.	Developer/Interconnection Customer	Project Name	Nameplate (MW)	Proposed In-Service
Other Projects (Permanent Solutions)	0766/0987	Sunrise Wind, LLC	Sunrise Wind	924	Winter 2028
	1289	New York Power Authority / New York Transco LLC.	Propel NY Energy - Alternate Solution 5	-	Summer 2030

Lower Hudson Valley

Now that CHPE has entered service and demonstrated its planned capability, the Lower Hudson Valley Near-Term Reliability Need identified in the 2026 Quarter 1 and Quarter 2 STARs is no longer observed, and the solution solicitation issued on August 20, 2026 is hereby withdrawn. Accordingly, the NYISO will not proceed with the evaluation or selection of solutions submitted in response to the August 20, 2026 solicitation.

In the 2026 Quarter 2 STAR, the NYISO and Central Hudson performed a deactivation assessment to evaluate the reliability impact of the proposed retirement of the Coxsackie GT. Central Hudson identified a non-BPTF Generator Deactivation Reliability Need. This need is the same as what was found by Central Hudson in the 2024 Quarter 1 STAR. In its most recent LTP update presented at the April 7, 2026 TPAS/ESPGWG meeting, Central Hudson indicated that the

STATCOM and capacitor bank at the New Baltimore 69 kV substation were expected to be in service by July 2026, with similar upgrades at the South Cairo 69 kV substation planned for March 2027. Central Hudson recently provided the NYISO an updated planned in-service date of the upgrades at the New Baltimore 69 kV substation as October 2026. Until these projects are in service and have demonstrated their expected performance, the non-BPTF Generator Deactivation Reliability Needs will persist. As such, it was determined that Cocksackie GT must remain in-service until these upgrades are completed.

Figure 10: Projects Identified to Address Central Hudson Non-BPTF Generator Deactivation Reliability Need

Projects to Identified to Address Central Hudson Local Generator Deactivation Reliability Needs		
Project	Area	Planned In-Service Date
Installation of STATCOM and Capacitor Bank at New Baltimore Substation	Westerlo 69 kV	October 2026
Installation of STATCOM and Capacitor Bank at South Cairo Substation	Westerlo 69 kV	March 2027

Conclusions

This 2026 Quarter 3 Short-Term Assessment of Reliability evaluated the reliability of the New York bulk electric grid for the period July 15, 2026 through July 15, 2031. Based on the assumptions and conditions evaluated in this assessment, the NYISO did not identify any new Bulk Power Transmission Facility (BPTF) Short-Term Reliability Process Needs. The NYISO also did not identify any BPTF Generator Deactivation Reliability Needs associated with the proposed retirement of ADK Resource Recovery, and National Grid similarly did not identify any local generator deactivation reliability needs associated with this retirement.

Since the start of this STAR, CHPE has demonstrated its planned capability as explained above. As a result, the Lower Hudson Valley Near-Term Reliability Need identified in the 2026 Quarter 1 and Quarter 2 STARS is no longer observed and the associated solution solicitation is hereby withdrawn. With CHPE having demonstrated its planned capability, Danskammer 1-4 may enter Mothball Outage²² and the associated Interim Service Provider rate will terminate after the NYISO provides at least 60 days prior notice to Danskammer, consistent with Section 38.13.2.4. of the OATT. ADK Resource Recovery may also retire on or after its proposed deactivation date of December 31, 2026.²³

This STAR finds that the reliability margins in the Lower Hudson Valley, New York City, and Long Island remain sufficient throughout the STAR study horizon. However, the margins within these localities over the near-term horizon continue to narrow. Reliability conditions remain dependent on the continued availability of existing resources, planned project performance, expected import capability, and forecast demand levels. Additional generator deactivations, reductions in imports, higher-than-forecast demand, or delays to planned projects could result in

²² Danskammer Energy, LLC's Generator Deactivation Notice requested an evaluation to become Retired. Danskammer Energy, LLC later requested to change its notice to enter a Mothball Outage. The NYISO determined that the change would not impact the NYISO's evaluation and is allowing Danskammer 1-4 to enter Mothball Outage. The associated Interim Service Provider rate will terminate after the NYISO provides at least 60 days prior notice to Danskammer. Danskammer Energy, LLC must complete all required NYISO administrative process and procedures prior to the deactivation of its generating units. See NYISO Technical Bulletin 185. The NYISO's determination in this Short-Term Reliability Process does not relieve Danskammer Energy, LLC of any obligations they have with respect to its Generators participation in the NYISO markets. If Danskammer Energy, LLC rescinds its Generator Deactivation Notice or does not place Danskammer 1-4 in a Mothball Outage within 730 days of January 15, 2026 then it will be required to submit a new Generator Deactivation Notice in order to deactivate the affected Generator(s) and will be required to repay study cost in accordance with Section 38.14 of the OATT.

²³ Consistent with Section 38.3.7 of the OATT, the earliest possible retirement date for Wheelabrator Hudson Falls, LLC, ADK Resource Recovery, is December 31, 2026. Wheelabrator Hudson Falls, LLC must complete all required NYISO administrative process and procedures prior to the retirement of its generating unit. See NYISO Technical Bulletin 185. The NYISO's determination in this Short-Term Reliability Process does not relieve Wheelabrator Hudson Falls, LLC of any obligations they have with respect to its Generators participation in the NYISO markets. If Wheelabrator Hudson Falls, LLC rescinds its Generator Deactivation Notice or does not retire ADK Resource Recovery within 730 days of July 15, 2026 then it will be required to submit a new Generator Deactivation Notice in order to deactivate the affected Generator(s) and will be required to repay study cost in accordance with Section 38.14 of the OATT.

reliability needs being identified in future STAR assessments.

Looking beyond the five-year STAR horizon, the draft 2026 RNA results identify three Reliability Needs: a statewide resource deficiency beginning in 2023, a transmission-constrained deficiency in New York City beginning in 2032, and a related need in the Lower Hudson Valley also beginning in 2032. Taken together, the findings in the 2026 RNA indicate that maintaining a reliable grid will require at least 1,850 MW of new generation resources appropriately located with the necessary operating characteristics coupled with transmission capability necessary to deliver those resources. In-state transmission alone will not resolve the statewide need.

The NYISO will continue to monitor evolving system conditions through both the Short-Term Reliability Process and the Reliability Planning Process.

Appendix A: List of Short-Term Reliability Needs

No new needs to report in this STAR.

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/SolutionStatusPosting-vFinal.pdf/>

Appendix C: Summary of Study Assumptions

This assessment used the major assumptions included in the 2026 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 2026 RNA study assumptions were reviewed with stakeholders at the May 6, 2026, joint ESPWG/TPAS meeting. Details regarding the 2026 Quarter 3 STAR study assumptions were reviewed with stakeholders at the August 3, 2026, joint ESPWG/ TPAS meeting. The meeting materials are posted on the NYISO's website.²⁴ The figures below (Figure 34, Figure 35, Figure 36, and Figure 37) summarize the changes to generation, load, and transmission.

Generation Assumptions

²⁴ Short-Term Assessment of Reliability: 2026 Q3 Key Study Assumptions, ESPWG/TPAS, August 3, 2026 ([here](#)). 2026 RNA Key Study Assumptions, ESPWG/TPAS, May 6, 2026 ([here](#)),

Figure 11: Completed Generator Deactivations

Owner/ Operator	Plant Name	Zone	Nameplate	CRIS (MW)		Capability (MW)		Status	Deactivation Date (2)	STAR Evaluation (3)
			(MW)	Summer	Winter	Summer	Winter			
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	4/1/2025	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	5/1/2025	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	9/5/2025	2025 Q1
Casella Waste Systems, Inc	Hyland LFGE	B	4.8	4.8	4.8	4.8	4.8	I	6/17/2025	2025 Q3
Relevate ReDev Borrower II LLC	Dahowa Hydro	F	12.3	10.5	10.5	12.3	12.3	I	9/1/2025	2025 Q4
MPH Cross Island Power, LLC	Pinelawn Power 1	K	82	78.0	78.0	73.6	76.5	R	8/12/2026	2025 Q3
WM Renewable Energy, LLC	High Acres	C	9.6	9.6	9.6	9.6	9.6	R	8/7/2026	2026 Q2
Total			4,695.4	4,298.3	4,624.9	4,093.0	4,464.8			

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.
- (5) A Generator Deactivation Assessment for the potential retirement of this unit with a deactivation date of 12/31/2024 was studied in the 2024 Q1 STAR.

Figure 12: 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 (3)	G	21.6	21.6	26.0	19.7	25.2	R	4/30/2027	2026 Q2
Danskammer Energy, LLC	Danskammer Units 1 through 4	G	532	511.1	511.1	498.3	505.0	MO	8/1/2026	2026 Q1
Total			553.6	532.7	537.1	518.0	530.2			

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 distribution solution to local non-BPTF transmission security issues is completed. At the April 7, 2025 TPAS/ESPPWG, Central Hudson presented an LTP update including a delay of the retirement of the Coxsackie GT until May 2026. At the April 2, 2026 TPAS/ESPPWG, Central Hudson presented in LTP update which continues to identify the retirement of the Coxsackie GT in April 2027.

Figure 13: Status Changes Due to DEC Peaker Rule

Owner/Operator	Station	Zone	Nameplate (MW)	CRIS (MW) (1)		Capability (MW) (1)		Status Change Date (2)
				Summer	Winter	Summer	Winter	
Central Hudson Gas & Elec. Corp.	Coxsackie GT (5)	G	21.6	21.6	26.0	19.4	24.0	04/30/2027
National Grid	Glenwood GT 03 (3)	K	55.0	54.7	71.5	53.0	65.5	N/A
National Grid	Shoreham 1 (3)	K	52.9	48.9	63.9	46.0	54.3	N/A
National Grid	Shoreham 2 (3)	K	18.6	18.5	23.5	16.7	21.3	N/A
Astoria Generating Company, L.P.	Gowanus 2-1 through 2-8 (4)(6)	J	160.0	152.8	199.6	141.2	176.3	5/1/2029
Astoria Generating Company, L.P.	Gowanus 3-1 through 3-8 (4)(6)	J	160.0	146.8	191.7	138.7	175.3	5/1/2029
Astoria Generating Company, L.P.	Narrows 1-1 through 2-8 (4)(6)	J	352.0	309.1	403.6	280.2	367.8	5/1/2029
Total			820.1	752.4	979.8	695.2	884.5	

Notes

1. MW values are from the 2026 Load and Capacity Data Report except where the 2026 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, or additional notifications to the DEC, 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. 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.
5. 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/ESPPWG, Central Hudson presented an LTP update including a delay of the retirement of the Coxsackie GT until May 2026. At the April 7, 2026 TPAS/ESPPWG, Central Hudson presented in LTP update which continues to identify the retirement of the Coxsackie GT in April 2027.
6. On April 15, 2026 the NYISO issued a letter to the DEC designating the Gowanus 2 & 3 and Narrows 1 & 2 generators as needed to address ongoing reliability needs until May 1, 2029. Extending these generators through May 1, 2029 helps alleviate the identified deficiencies, but without additional supply resources, reliability needs will likely develop at the end of the five-year horizon or shortly after it. Subsequently, on April 16, 2026, AlphaGen withdrew their generator deactivation notice for these units.

Figure 14: Large Generation Additions

Proposed Project Inclusion: Large Generation					
Queue	Project Name	MW	Type	Zone	Proposed Date
276	Homer Solar Energy Center	90	Solar	C	Apr-26
396	Baron Winds Phase II	117	Land-Based Wind	C	Dec-26
519	Canisteo Wind Energy LLC	290.7	Land-Based Wind	C	Dec-27
571	Heritage Wind, LLC	126	Land-Based Wind	B	Oct-27
596	Alle Catt II Wind	339.1	Land-Based Wind	A	Dec-26
704	Bear Ridge Solar	100	Solar	A	Apr-28
710	Horseshoe Solar Energy LLC	180	Solar	B	May-28
716	Moraine Solar Energy Center	93.5	Solar	C	Sep-28
720	Trelina Solar Energy Center	79.8	Solar	C	Apr-28
721	Excelsior Energy Center	280	Solar	A	Nov-26
737	Empire Wind 1	816	Offshore Wind	J	Jul-27
766	Sunrise Wind	880	Offshore Wind	K	Jul-27
774	Tracy Solar Energy Centre	119	Solar	E	Dec-28
801	Prattsburgh Wind, LLC	147	Land-Based Wind	C	Sep-27
811	Hecate Energy Cider Solar LLC	500	Solar	B	Jan-27
815	Bayonne Energy Center	49.8	Energy Storage	J	Jul-27
880	Brookside Solar	100	Solar	D	Dec-27
883	Garnet Energy Center, LLC	200	Solar	B	Apr-28
931	Astoria Energy Storage	100	Energy Storage	J	Oct-26
950	Hemlock Ridge Solar	200	Solar	B	Apr-28
987	Sunrise Wind II	44	Offshore Wind	K	Jul-27
1009	Yellow Barn Solar	160	Solar	C	Nov-28
1031	Mill Point Solar	250	Solar+Energy Storage	E	Dec-28
1183	NY125A - Fort Covington Solar	250	Solar	D	Jul-28
1184	NY125B - Two Rivers Solar	200	Solar	D	Sep-28

Figure 15: Small Generation Additions

Proposed Project Inclusion: Small Generation					
Queue	Project Name	MW	Type	Zone	Proposed Date
564	Rock District Solar	20	Solar	F	Feb-27
572	Greene County 1	20	Solar	G	Jun-27
573	Greene County 2	10	Solar	G	Jun-27
575	Little Pond Solar	20	Solar	G	Sep-27
581	Hills Solar	20	Solar	E	Dec-26
584	Dog Corners Solar	20	Solar	C	Jan-27
586	Watkins Rd Solar	20	Solar	E	Feb-27
590	Scipio Solar	18	Solar	C	Dec-26
670	SunEast Skyline Solar LLC	20	Solar	E	Apr-28
734	Ticonderoga Solar	20	Solar	F	Dec-26
804	KCE NY 10	20	Energy Storage	A	Oct-26
827	Arthur Kill Energy Storage 1	15	Energy Storage	J	Dec-26
828	Valley Solar	20	Solar	C	Jan-27
832	CS Hawthorn Solar	20	Solar	F	Dec-26
833	Dolan Solar	20	Solar	F	Dec-26
865	Flat Hill Solar	20	Solar	E	Aug-27
885	Grassy Knoll Solar	20	Solar	E	May-28
1003	Clear View Solar	20	Solar	C	Aug-26
1015	Somers Solar, LLC	20	Solar	F	Dec-26
1047	Millers Grove Solar	20	Solar	E	Mar-28
1166	BR Benson Mines Solar	12	Solar	E	Dec-27
1329	ELP Granby Solar II	20	Solar + Energy Storage	C	Jun-28

Demand Assumptions

The 2026 Quarter 3 STAR uses the demand forecasts for the study years consistent with the 2026 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. For the transmission security margin assessment, the 2025 Quarter 3 STAR uses forecast information from the 2026 Gold Book.

Figure 16: Summer Coincident Peak Demand Forecasts (2026 Gold Book)

Summer Coincident Peak Demand Forecast (MW)													
Year	Forecast	A	B	C	D	E	F	G	H	I	J	K	NYCA
2027	Low Demand	2,792	1,774	2,472	665	1,212	2,219	2,255	607	1,331	10,700	4,973	31,000
	Baseline	2,994	1,784	2,489	935	1,216	2,244	2,381	614	1,346	10,830	5,047	31,880
	High Demand	3,015	1,852	2,513	952	1,268	2,252	2,385	618	1,351	10,960	5,054	32,220
2028	Low Demand	2,867	1,734	2,437	658	1,186	2,188	2,247	607	1,330	10,690	4,956	30,900
	Baseline	2,971	1,919	2,458	927	1,221	2,218	2,377	615	1,352	10,850	5,072	31,980
	High Demand	3,093	1,960	2,512	963	1,305	2,286	2,388	620	1,358	11,010	5,085	32,580
2029	Low Demand	2,898	1,722	2,428	651	1,166	2,158	2,240	606	1,330	10,660	4,931	30,790
	Baseline	2,933	2,032	2,446	917	1,190	2,192	2,408	615	1,357	10,870	5,110	32,070
	High Demand	3,263	2,115	2,521	1,120	1,288	2,352	2,429	621	1,366	11,090	5,125	33,290
2030	Low Demand	2,855	1,699	2,506	642	1,145	2,130	2,223	604	1,329	10,620	4,907	30,660
	Baseline	2,908	2,111	2,523	912	1,168	2,178	2,410	617	1,362	10,900	5,161	32,250
	High Demand	3,251	2,198	2,740	1,121	1,281	2,367	2,440	627	1,373	11,140	5,202	33,740
2031	Low Demand	2,813	1,681	2,609	633	1,125	2,097	2,193	599	1,328	10,530	4,872	30,480
	Baseline	2,891	2,122	2,625	908	1,151	2,171	2,416	619	1,369	10,930	5,218	32,420
	High Demand	3,239	2,204	2,977	1,217	1,276	2,375	2,455	628	1,380	11,200	5,279	34,230

Figure 17: Winter Coincident Peak Demand Forecasts (2026 Gold Book)

Winter Coincident Peak Demand Forecast (MW)													
Year	Forecast	A	B	C	D	E	F	G	H	I	J	K	NYCA
2027-28	Low Demand	2,156	1,464	2,500	819	1,281	1,885	1,656	506	941	7,620	3,232	24,060
	Baseline	2,359	1,581	2,529	1,098	1,341	1,922	1,792	511	965	7,700	3,312	25,110
	High Demand	2,484	1,602	2,562	1,124	1,356	1,978	1,807	517	976	7,830	3,324	25,560
2028-29	Low Demand	2,194	1,442	2,520	814	1,255	1,871	1,662	508	947	7,630	3,247	24,090
	Baseline	2,356	1,693	2,524	1,093	1,342	1,926	1,826	518	984	7,750	3,398	25,410
	High Demand	2,622	1,714	2,570	1,207	1,354	2,052	1,862	522	1,001	7,880	3,416	26,200
2029-30	Low Demand	2,224	1,423	2,545	809	1,228	1,857	1,658	510	953	7,640	3,253	24,100
	Baseline	2,365	1,868	2,567	1,089	1,344	1,932	1,864	523	1,002	7,810	3,516	25,880
	High Demand	2,719	1,904	2,776	1,284	1,361	2,118	1,910	533	1,036	8,070	3,539	27,250
2030-31	Low Demand	2,235	1,403	2,586	804	1,204	1,844	1,662	512	960	7,650	3,260	24,120
	Baseline	2,376	1,916	2,673	1,085	1,345	1,938	1,906	527	1,023	7,900	3,621	26,310
	High Demand	2,767	1,955	2,858	1,323	1,368	2,147	1,977	536	1,064	8,190	3,685	27,870
2031-32	Low Demand	2,228	1,379	2,634	800	1,184	1,830	1,662	513	964	7,690	3,266	24,150
	Baseline	2,396	1,919	2,766	1,082	1,347	1,953	1,936	532	1,045	7,990	3,724	26,690
	High Demand	2,817	1,980	3,077	1,369	1,374	2,174	2,010	541	1,081	8,300	3,867	28,590

Figure 18: Annual Energy Forecasts (2026 Gold Book)

Annual Energy Forecast (GWh)													
Year	Forecast	A	B	C	D	E	F	G	H	I	J	K	NYCA
2027	Low Demand	15,040	9,160	14,290	5,400	6,900	11,250	9,580	2,660	5,760	50,020	19,670	149,730
	Baseline	16,600	9,380	14,430	6,780	7,010	11,370	10,220	2,690	5,830	50,670	20,050	155,030
	High Demand	16,790	9,470	14,560	6,830	7,160	11,490	10,310	2,720	5,880	51,320	20,240	156,770
2028	Low Demand	15,570	9,080	14,060	5,360	6,630	11,070	9,580	2,660	5,780	50,040	19,660	149,490
	Baseline	16,500	10,090	14,240	7,420	7,060	11,220	10,490	2,700	5,890	50,880	20,270	156,760
	High Demand	17,400	10,230	14,460	7,630	7,330	11,620	10,640	2,740	5,980	51,930	20,570	160,530
2029	Low Demand	15,990	8,940	13,990	5,290	6,440	10,900	9,580	2,650	5,770	49,850	19,650	149,050
	Baseline	16,380	10,870	14,240	7,370	6,970	11,110	10,690	2,690	5,910	50,940	20,570	157,740
	High Demand	18,600	11,070	14,780	8,450	7,290	12,190	10,900	2,750	6,030	52,400	20,990	165,450
2030	Low Demand	15,980	8,860	14,690	5,250	6,310	10,800	9,580	2,640	5,750	49,800	19,640	149,300
	Baseline	16,330	11,710	15,010	7,340	6,880	11,080	10,850	2,710	5,950	51,180	21,120	160,160
	High Demand	18,900	11,960	16,110	8,670	7,250	12,520	11,130	2,790	6,110	53,070	21,670	170,180
2031	Low Demand	15,870	8,790	15,320	5,200	6,210	10,730	9,560	2,640	5,780	49,780	19,630	149,510
	Baseline	16,320	11,760	15,750	7,310	6,830	11,080	10,960	2,720	6,020	51,540	21,540	161,830
	High Demand	18,980	12,080	17,570	9,160	7,250	12,730	11,310	2,820	6,220	53,880	22,220	174,220

Figure 19: Summer Non-Coincident Peak Demand Forecast (2026 Gold Book)

Summer Non-Coincident Peak Demand Forecast (MW)				
Year	Forecast	Zone		
		G-J	J	K
2027	Low Demand	15,260	10,960	5,061
	Baseline	15,551	11,100	5,136
	High Demand	15,694	11,230	5,143
2028	Low Demand	15,241	10,950	5,043
	Baseline	15,574	11,120	5,161
	High Demand	15,757	11,280	5,174
2029	Low Demand	15,203	10,920	5,018
	Baseline	15,631	11,140	5,200
	High Demand	15,888	11,360	5,215
2030	Low Demand	15,142	10,880	4,993
	Baseline	15,670	11,170	5,252
	High Demand	15,963	11,410	5,294
2031	Low Demand	15,015	10,790	4,958
	Baseline	15,716	11,200	5,310
	High Demand	16,046	11,470	5,372

Figure 20: Winter Non-Coincident Peak Demand Forecast (2026 Gold Book)

Winter Non-Coincident Peak Demand Forecast (MW)				
Year	Forecast	Zone		
		G-J	J	K
2027-28	Low Demand	10,795	7,670	3,245
	Baseline	11,040	7,750	3,325
	High Demand	11,202	7,880	3,337
2028-29	Low Demand	10,819	7,680	3,260
	Baseline	11,150	7,800	3,412
	High Demand	11,348	7,940	3,430
2029-30	Low Demand	10,833	7,690	3,266
	Baseline	11,272	7,860	3,530
	High Demand	11,632	8,130	3,553
2030-31	Low Demand	10,856	7,700	3,273
	Baseline	11,439	7,960	3,635
	High Demand	11,850	8,250	3,700
2031-32	Low Demand	10,901	7,740	3,279
	Baseline	11,586	8,050	3,739
	High Demand	12,015	8,360	3,882

Figure 21: Large Load Demand Forecast (2026 Gold Book)

Large Loads Summer Peak Forecast (MW)													
Year	A	B	C	D	E	F	G	H	I	J	K	NYCA Total	Flexible Total
2027	440	11	0	435	15	0	173	0	0	0	1	1,075	675
2028	440	161	0	435	65	0	184	0	0	0	7	1,292	675
2029	440	291	30	435	65	0	227	0	0	0	29	1,517	675
2030	440	411	170	435	65	0	241	0	0	0	69	1,831	675
2031	440	411	270	435	65	0	255	0	0	0	113	1,989	675
Large Loads Winter Peak Forecast (MW)													
Year	A	B	C	D	E	F	G	H	I	J	K	NYCA Total	Flexible Total
2027-28	440	91	0	435	40	0	173	0	0	0	3	1,182	675
2028-29	440	191	0	435	65	0	184	0	0	0	36	1,351	675
2029-30	440	381	70	435	65	0	227	0	0	0	71	1,689	675
2030-31	440	411	180	435	65	0	241	0	0	0	136	1,908	675
2031-32	440	411	280	435	65	0	255	0	0	0	189	2,075	675

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

Transmission Assumptions

The study assumptions for existing transmission facilities that are modeled as out-of-service are listed in Figure 23. Figure 23 includes planned status of the Con Edison series reactor used in this STAR consistent with the 2026 FERC 715 filing. Figure 24 and Figure 25 provide a summary of the transmission projects included in the 2026 RNA as listed in the 2026 Gold Book.

Figure 22: Existing Transmission Facilities Modeled Out-of-Service

From	To	kV	ID	Out-of-Service Through	
				Prior STAR	This STAR
Marion	Farragut	345	B3402	Long-Term	
Marion	Farragut	345	C3403	Long-Term	
Plattsburgh (1)	Plattsburgh	230/115	AT1	9/2026	5/2027
Station 23	Station 42	115	920	12/2026	5/2027
E13th Street		345/69	BK17	6/2027	

Notes:

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

Figure 23: Con Edison Planned Series Reactor Status

Terminals		ID	kV	Summer		Winter	SLL
				2027	Post-2027		
Dunwoodie	Mott Haven	71	345	In-Service	In-Service	By-Passed	By-Passed
Dunwoodie	Mott Haven	72	345	In-Service	In-Service	By-Passed	By-Passed
Sprainbrook	W. 49th Street	M51	345	In-Service	In-Service	By-Passed	By-Passed
Sprainbrook	W. 49th Street	M52	345	In-Service	In-Service	By-Passed	By-Passed
Farragut	Gowanus	41	345	By-Passed	In-Service	In-Service	In-Service
Farragut	Gowanus	42	345	By-Passed	In-Service	In-Service	In-Service
Sprainbrook	Uniondale Hub	Y49	345	By-Passed	By-Passed	By-Passed	By-Passed

Figure 24: Major Transmission Projects Included in 2026 RNA

Queue	Project Name	MW	POI	Zone	Proposed Date
631/887	TDI Champlain Hudson Power Express (CHPE)	1,250	Astoria Annex 345kV	J	In-service
1125	Northern New York Priority Transmission Project (NNYPTP)	N/A	Moses/Adirondack/Porter path	D&E	In-service
-	Goethals/Foxhills PAR Regulated Feeder	N/A	Goethals 345 kV/Greenwood 138 kV TLA	J	In-service
-	Gowanus/Greenwood PAR Regulated Feeder (third connection)	N/A	Gowanus 345 kV/Greenwood 138 kV TLA	J	In-service
-	Gowanus/Greenwood PAR Regulated Feeder (fourth connection)	N/A	Gowanus 345 kV/Greenwood 138 kV TLA	J	Summer-26
-	Brooklyn Clean Energy Hub	N/A	Between Farragut 345 kV and Rainey 345 kV	J	Summer-28
-	Eastern Queens Clean Energy Hub	N/A	Between Jamaica 138 kV and Valley Stream/Lake Success 138 kV	J	Summer-28
1289	Propel NY Energy - Alternate Sol 5 (T051 LIPPTN)	N/A	Sprain Brook, Tremont, East Garden City, Shore Road, additional Long Island Substations	I,J,K	Summer-29

Figure 25: Transmission Projects Not Included in the RNA or STAR Base Case

Transmission Project Inclusion Rules Application: Class Year Transmission, TIP, and Firm LTP Projects Not Included in the RNA Base Cases											
Transmission Owner	Terminals		Line Length (Miles) (1)	Proposed In-Service Date		Nominal Voltage (kV)		# of CKTs	Thermal Ratings (3)		Project Description / Conductor Size
				Prior to (2)	Year	Operating	Design		Summer	Winter	
NGRID	Reynolds Rd	Reynolds Rd	-	W	2030	345/115	345/115	-	N/A	N/A	115 kV relaying additions and upgrades
NGRID	Clay	Dewitt	15.7	W	2030	115	115	1	973	1234	Replace existing switch and include remote control capability
NGRID	Dewitt	Dewitt	Substation	W	2030	115	115	-	N/A	N/A	Rebuild DeWitt 115 kV Substation
NGRID	Clay	Dewitt	15.41	W	2030	115	115	1	973	1234	115 kV Taps to new Distribution Station
NGRID	Clay	Teall	11.73	W	2030	115	115	1	1172	1434	115 kV Taps to new Distribution Station
NYSEG	South Owego	Oakdale	18	W	2030	115	115	1	288 MVA	346 MVA	Rebuild the existing 18 mile 115 kV line #961 with 1192 ACSR conductor. Modify terminal bay at South Owego
NYSEG	Oakdale 345	Oakdale 345	Rebuild	S	2031	345	345		N/A	N/A	Expand existing 345 kV bus to 3 bay BAAH. (4)
NYSEG	Oakdale 115	Oakdale 115	Rebuild	S	2031	115	115		N/A	N/A	Complete rebuild of 115 kV to 6 bay BAAH. (4)
NYSEG	Westover 115	Westover	Removal	S	2031	115	115		N/A	N/A	Retire 115 kV Westover Substation. Rebuild Westover 34.5 kV out of flood zone.
NYSEG	Oakdale 345	Oakdale 115	xfmr	S	2031	345/115/34.5	345/115/34.5	1	448 MVA	464 MVA	Add one new 345/115/34.5 kV Transformer (4)
NYSEG	Oakdale 345	Oakdale 115	xfmr	S	2031	345/115/34.5	345/115/34.5	2	448 MVA	464 MVA	Replace Existing B2 & B3 Transformers (4)
NYSEG	Canandaigua	Stoney Ridge	24	S	2031	230	230	1	795 MVA	853 MVA	Rebuild the existing 24 mile 230 kV line #68 with mile 230 kV line with bundled 1192 Bunting ACSR ACSR conductor.
NYSEG	Stolle Rd	Stolle Rd	Rebuild	S	2031	115	115		N/A	N/A	Partial Rebuild of 115 kV to a BAAH in the existing yard. 3 Position 345 kV Ring Bus. 34.5 kV GIS Straight bus with a tie breaker.
NYSEG	Stolle Rd	Stolle Rd	xfmr	S	2031	345/115	345/115	1	448 MVA	448 MVA	One (1) 448 MVA 345/115 kV Transformer
NYSEG	Stolle Rd	Stolle Rd	xfmr	S	2031	345/230	345/230	1	488 MVA	488 MVA	One (1) 448 MVA 345/230 kV Transformer
NYSEG	Robinson Rd	Robinson Rd	Rebuild	S	2031	115	115		N/A	N/A	New four (4) bay 115 kV AIS BAAH. Demolish Hinman Rd 115/34.5 kV Station. Reroute 115 kV and 34.5 kV circuits from Hinman Rd to Robinson Rd. New 34.5 kV MV GIS at Robinson Rd
NYSEG	Robinson Rd	Robinson Rd	xfmr	S	2031	230/115/34.5	230/115/34.5	1	297 MVA	297 MVA	New 230/115/34.5 kV transformer
NYSEG	Robinson Rd	Robinson Rd	xfmr	S	2031	115/34.5	115/34.5	3	50 MVA	60 MVA	Three new 115/34.5 transformers
NYSEG	Stoney Ridge	Hillside	27	S	2031	230	230	1	795 MVA	886 MVA	Rebuild the existing 27 mile 230 kV line #72 with 2156 Bluebird ACSR conductor.

Note:

1. Line Length Miles: Negative values indicate removal of Existing Circuit being tapped.
2. S = Summer, W = Winter. Winter refers to the winter beginning with the year listed. For example, W 2026 refers to winter 2026-27.
3. Thermal Ratings in Amperes, except where labeled otherwise.
4. Following the start of the RNA, the NYISO included these projects.

Appendix D: Resource Adequacy Assumptions

2026 Q3 STAR MARS Assumptions Matrix

	Parameter	2024 RNA Base Cases Key Assumptions (2024 Gold Book)	2025 RPP, 2025 Q4 STAR Key Assumptions (2025 Gold Book)	2026 RNA Key Assumptions (2026 Gold Book)
0	Relevant Links	2024 RNA Report Appendices 2025-2034 CRP Report Appendices	- July 23 ESPWG 2025 Q3 STAR Assumptions - Nov. 10, 2025 Q3 STAR Solutions Solicitation - Nov 7 ESPWG 2025 Q4 STAR Assumptions	October 1, 2026 ESPWG/TPAS Draft 2 Report October 8, 2026 ESPWG/TPAS Draft 2 Report Draft 1 Appendix August 3, 2026 ESPWG/TPAS 2026 Q3 STAR Key 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. 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. 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.	Adjusted 2026 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. The 2026 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 model, which then allows for a discrete modeling of the BtM solar resources.
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.	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 either EOP step or as part of the DER

	Parameter	2024 RNA Base Cases Key Assumptions (2024 Gold Book)	2025 RPP, 2025 Q4 STAR Key Assumptions (2025 Gold Book)	2026 RNA Key Assumptions (2026 Gold Book)
				program if elected to participate.
2	Load Shapes (Multiple Load Shapes)	Used Multiple Load Shape MARS Feature (see <i>March 24, 2022 LFTF/ESPGWG</i>). 8,760-hour historical gross load shapes were used as base shapes for LFU bins: - Load Bins 1 and 2: 2013 - Load Bins 3 and 4: 2018 - Load Bins 5 to 7: 2017 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. 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 <i>March 24, 2022 LFTF/ESPGWG</i>). 8,760-hour historical gross load shapes were used as base shapes for LFU bins: - Load Bins 1 and 2: 2013 - Load Bins 3 and 4: 2018 - Load Bins 5 to 7: 2017 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. 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 <i>March 24, 2022 LFTF/ESPGWG</i>). 8,760-hour historical gross load shapes were used as base shapes for LFU bins: - Load Bins 1 and 2: 2013 - Load Bins 3 and 4: 2018 - Load Bins 5 to 7: 2017 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. 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)	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 <i>May 26, 2023 LFTF [link]</i> and also presented at the <i>April 18, 2024 LFTF [link]</i>) New Additional Method for Winter: Winter Dynamic Load Forecast Uncertainty (LFU): In order to reflect uncertainty stemming from 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 match those calculated using recent winter load and weather data.	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 <i>May 26, 2023 LFTF [link]</i> and also presented at the <i>April 18, 2024 LFTF [link]</i>) Starting 2024 RNA, winter Dynamic Load Forecast Uncertainty (LFU): In order to reflect uncertainty stemming from electrification, electric vehicles (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 match those calculated using recent winter load and weather data.	The LFU model captures the impacts of weather conditions on future loads. Summer and Winter LFU values presented at the July 1, 2026 LFTF [Link] Starting 2024 RNA, winter Dynamic Load Forecast Uncertainty (LFU): In order to reflect uncertainty stemming from electrification, electric vehicles (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 match those calculated using recent winter load and weather data.

	Parameter	2024 RNA Base Cases Key Assumptions (2024 Gold Book)	2025 RPP, 2025 Q4 STAR Key Assumptions (2025 Gold Book)	2026 RNA Key Assumptions (2026 Gold Book)
		Additional details are available in the April 18 TPAS/ESPGW/LFTF presentation [link]	Additional details are available in the May 29 TPAS/ESPGW/LFTF presentation [link]	
Generation Parameters				
1	Existing Generating Unit Capacities (e.g., thermal units, large hydro)	2024 Gold Book values: Summer is min of (DMNC, CRIS). Winter is min of (DMNC, CRIS). Adjusted for RNA Base Case inclusion rules application	2025 Gold Book values: Summer is min of (DMNC, CRIS). Winter is min of (DMNC, CRIS). Adjusted for RNA Base Case inclusion rules application	2026 Gold Book values: Summer is min of (DMNC, CRIS). Winter is min of (DMNC, CRIS). 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	2026 Gold Book and market participant input 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	2026 Gold Book and market participant input with RNA Base Case inclusion rules applied
4	Statistical Retirement Risk	N/A	N/A	New method: ²⁵ Aging generation impacts will be captured for thermal fossil units using the statistical retirement risk model described in Attachment H of the Reliability Planning Process Manual. The P95 threshold age will be applied, and the EIA 860M February 2026 Monthly Generator Inventory data will be used.
5	Forced and Partial Outage Rates (e.g., thermal units)	Five-year (2019-2023) GADS data for each unit represented. Transition Rates representing the Equivalent Forced Outage Rates (EFORd) during demand periods over the most recent five-year period. 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. Transition Rates representing the Equivalent Forced Outage Rates (EFORd) during demand periods over the most recent five-year period. 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 (2021-2025) GADS data for each unit represented. Transition Rates representing the Equivalent Forced Outage Rates (EFORd) during demand periods over the most recent five-year period. For new units or units that are in service for less than three years, NERC 5-year class average EFORd data are used.
6	Modeling of Non-firm Gas Unavailability During Winter Peak Conditions	New: 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-	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	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-

²⁵ See Reliability Planning Process Manual (June 1, 2026) at Section 3.2.3 and Attachment H.

	Parameter	2024 RNA Base Cases Key Assumptions (2024 Gold Book)	2025 RPP, 2025 Q4 STAR Key Assumptions (2025 Gold Book)	2026 RNA Key Assumptions (2026 Gold Book)
		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.	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.	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.
7	Daily Maintenance	Fixed maintenance based on schedules received by the NYISO.	Fixed maintenance based on schedules received by the NYISO.	Fixed maintenance based on schedules received by the NYISO.
8	Weekly Planned Maintenance	After planned daily maintenance is applied for the near future, MARS automatically schedules maintenance based on NYCA capacity and demand. 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.	After planned daily maintenance is applied for the near future, MARS automatically schedules maintenance based on NYCA capacity and demand. 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.	After planned daily maintenance is applied for the near future, MARS automatically schedules maintenance based on NYCA capacity and demand. Data: 5y (2021-2025) of historical scheduled maintenance data from Operations and GADS system to determine the number of weeks on maintenance for each thermal unit.
9	Summer Maintenance	None	None	None
10	Combustion Turbine Derates	Derate based on temperature correction curves. Thermal derates are based on a ratio of peak load before LFU is applied and LFU applied load. For new units: used data for a unit of same type in same zone, or neighboring zone data.	Derate based on temperature correction curves. Thermal derates are based on a ratio of peak load before LFU is applied and LFU applied load. For new units: used data for a unit of same type in same zone, or neighboring zone data.	Derate based on temperature correction curves. Thermal derates are based on a ratio of peak load before LFU is applied and LFU applied load. For new units: used data for a unit of same type in same zone, or neighboring zone data.
11	Existing Landfill Gas (LFG) Plants	Actual hourly plant output is derived from the most recent available data 2017–2021 across all hourly generation shapes. In each Monte Carlo replication, one LFG hourly production shape is randomly selected from the dataset, with all shapes assigned equal probability.	Actual hourly plant output is derived from the most recent available data 2020–2024 across all hourly generation shapes. In each Monte Carlo replication, one LFG hourly production shape is randomly selected from the dataset, with all shapes assigned equal probability.	Actual hourly plant output is derived from the most recent available data 2020–2024 across all hourly generation shapes. In each Monte Carlo replication, one LFG hourly production shape is randomly selected from the dataset, with all shapes assigned equal probability.
12	Existing and Proposed Wind Units	New data source: Model-based hourly data derived from the most recent available data (2017-2021, developed by DNV-GL) across all hourly generation shapes. Probabilistic model is incorporated based on five years of input shapes, with one shape per replication randomly selected with equal probability in the Monte Carlo process.	Model-based hourly data derived from the most recent available data (2020-2024, developed by DNV-GL) across all hourly generation shapes. Probabilistic model is incorporated based on five years of input shapes, with one shape per replication randomly selected with equal probability in the Monte Carlo process.	Model-based hourly data derived from the most recent available data (2020-2024, developed by DNV-GL) across all hourly generation shapes. Probabilistic model is incorporated based on five years of input shapes, with one shape per replication randomly selected with equal probability in the Monte Carlo process.

	Parameter	2024 RNA Base Cases Key Assumptions (2024 Gold Book)	2025 RPP, 2025 Q4 STAR Key Assumptions (2025 Gold Book)	2026 RNA Key Assumptions (2026 Gold Book)
13	Existing and Proposed Offshore Wind Units	New data source: Model-based hourly data derived from the most recent available data (2017-2021) across all hourly generation shapes Probabilistic model is incorporated based on five years of input shapes, with one shape per replication randomly selected with equal probability in the Monte Carlo process.	Model-based hourly data derived from the most recent available data (2020-2024) across all hourly generation shapes Probabilistic model is incorporated based on five years of input shapes, with one shape per replication randomly selected with equal probability in the Monte Carlo process.	Model-based hourly data derived from the most recent available data (2020-2024) across all hourly generation shapes Probabilistic model is incorporated based on five years of input shapes, with one shape per replication randomly selected with equal probability in the Monte Carlo process.
14	Existing and Proposed Utility-scale Solar Resources	New data source: Model-based hourly data derived from the most recent available data (2017-2021) across all hourly generation shapes Probabilistic model is incorporated based on five years of input shapes, with one shape per replication randomly selected with equal probability in the Monte Carlo process	Model-based hourly data derived from the most recent available data (2020-2024) across all hourly generation shapes Probabilistic model is incorporated based on five years of input shapes, with one shape per replication randomly selected with equal probability in the Monte Carlo process	Model-based hourly data derived from the most recent available data (2020-2024) across all hourly generation shapes Probabilistic model is incorporated based on five years of input shapes, with one shape per replication randomly selected with equal probability in the Monte Carlo process.
15	BtM Solar Resources	Supply side: Past five years (2017-2021) of 8,760 hourly MW profiles based on sampled inverter data. . In each Monte Carlo replication, one BTM hourly shape is randomly selected from this dataset, with all shapes assigned equal probability. Load side: Gross load forecasts	Supply side: Past five years (2020-2024) of 8,760 hourly MW profiles based on sampled inverter data. In each Monte Carlo replication, one BTM hourly shape is randomly selected from this dataset, with all shapes assigned equal probability. Load side: Gross load forecasts	Supply side: In order to better preserve the correlation between BTM PV production and load, the use of five historical BTM PV shapes is being replaced with a set of five performance factors applied to the 2013 BTM PV shape. The five performance factors are calculated using estimated actual BTM solar generation during high load days over recent years. These factors represent the typical range of BTM solar variability that can be expected during high load days, expressed as five ratios: two with above average solar generation, one with average solar generation (approximately 1.0), and two with below average solar generation. These factors are applied to the 2013 historical BTM PV shape to generate five 8,760-hour profiles, maintaining the inherent correlation of BTM solar and load in the most impactful load bins. In each Monte Carlo replication, one BTM hourly shape is randomly selected from this dataset, with all shapes assigned equal probability. Load side: Gross load forecasts

	Parameter	2024 RNA Base Cases Key Assumptions (2024 Gold Book)	2025 RPP, 2025 Q4 STAR Key Assumptions (2025 Gold Book)	2026 RNA Key Assumptions (2026 Gold Book)
16	Existing BTM-NG Program	These units are former load modifiers that sell capacity into the ICAP market. 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. 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. 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.
17	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.	Actual hourly plant output is derived from the most recent available data (2020–2024) across all hourly generation shapes. In each Monte Carlo replication, one hydro hourly production shape is randomly selected from this dataset, with all shapes assigned equal probability.
18	Existing Large Hydro	Probabilistic Model based on 5 years of GADS data. 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. 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. 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.
19	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. Limited to one charge/discharge cycle per day	GE MARS 'ES' model is used. Units are given a maximum capacity, maximum stored energy, and a dispatch window. Limited to one charge/discharge cycle per day	GE MARS 'ES' model is used. Units are given a maximum capacity, maximum stored energy, and a dispatch window. Limited to one charge/discharge cycle per day.
20	Existing Energy Limited Resources (ELRs)	GE developed MARS functionality to be used for ELRs. Resource output is aligned with the hours when loss-of-load events are likely to occur.	GE developed MARS functionality to be used for ELRs. Resource output is aligned with the hours when loss-of-load events are likely to occur.	GE developed MARS functionality to be used for ELRs. Resource output is aligned with the hours when loss-of-load events are likely to occur.
21	Distributed Energy Resources (DER)	N/A	N/A	New type: New market participation 2025 program allowing resources to enroll and participate in any of the NYISO markets. Initial program registration: 2025. Also, certain existing resources (including large loads) elected to move from the SCR program into the DER program. DER aggregations with duration limits are represented as energy-limited resources and aggregated by zone, technology type, and duration. DER aggregations without duration limits are aggregated by zone and

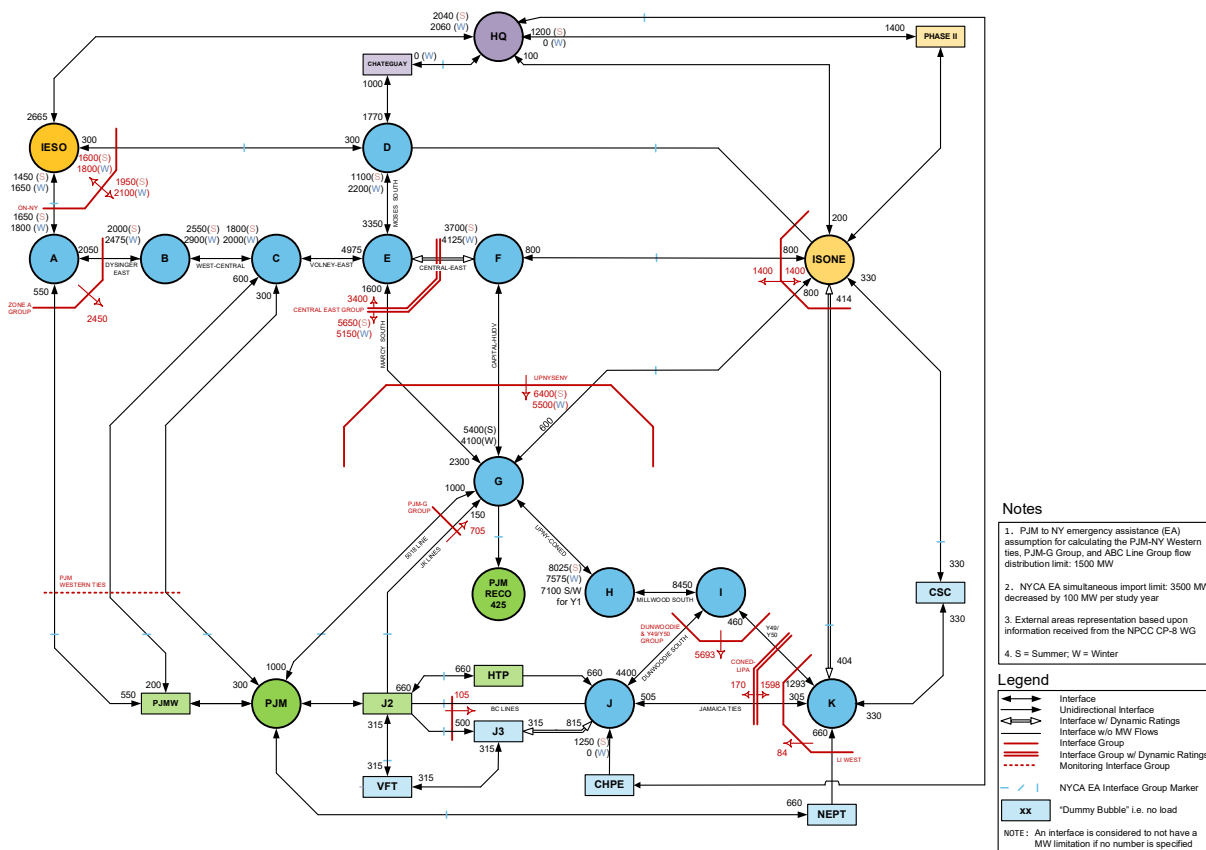
	Parameter	2024 RNA Base Cases	2025 RPP, 2025 Q4 STAR	2026 RNA
		Key Assumptions (2024 Gold Book)	Key Assumptions (2025 Gold Book)	Key Assumptions (2026 Gold Book)
				technology into a single resource. DERs registered as Energy Storage Resources (ESRs) are represented consistent with existing planning assumptions for energy storage units. Demand-side resources participating as DERs are also represented as energy-limited resources; DERs without a duration election are treated as 24-hour resources.
Transaction – Imports/ Exports				
1	Capacity Purchases	Grandfathered Rights and other awarded long-term rights Modeled using MARS explicit contracts feature.	Grandfathered Rights and other awarded long-term rights Modeled using MARS explicit contracts feature.	Grandfathered Rights and other awarded long-term rights Modeled using MARS explicit contracts feature.
2	Capacity Sales	These are long-term contracts filed with FERC. 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. 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. 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 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 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 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) 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) 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) 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.	Cedars Uprate 80 MW. Modeled reflecting External CRIS rights.
6	Wheel-Through Contract	300 MW HQ through NYISO to ISO-NE. 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. 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. 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.

	Parameter	2024 RNA Base Cases Key Assumptions (2024 Gold Book)	2025 RPP, 2025 Q4 STAR Key Assumptions (2025 Gold Book)	2026 RNA Key Assumptions (2026 Gold Book)
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.	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.	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.	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.	Ten-year history of forced outages.
Emergency Operating Procedures (EOPs)				
1	EOP Steps Order	New order, and new flexible large loads at step 2: - No EOP Support - Flexible Large Loads - Special Case Resources (SCRs) (Load and Generator) 5% Manual Voltage Reduction 30-Minute Operating Reserve to Zero (655 MW) - Voluntary Load Curtailment - Public Appeals 5% Remote Controlled Voltage Reduction - Emergency Assistance from External Areas - Part of the 10-Minute Operating Reserve (910 MW of 1310 MW) to Zero	Starting 2024 RNA, new EOP order and flexible large loads: - No EOP Support - Flexible Large Loads - Special Case Resources (SCRs) (Load and Generator) 5% Manual Voltage Reduction 30-Minute Operating Reserve to Zero (655MW) - Voluntary Load Curtailment - Public Appeals 5% Remote Controlled Voltage Reduction - Emergency Assistance from External Areas - Part of the 10-Minute Operating Reserve (910 MW of 1310 MW) to Zero	Starting 2024 RNA, new EOP order and flexible large loads: - No EOP Support - Flexible Large Loads - Special Case Resources (SCRs) (Load and Generator) 5% Manual Voltage Reduction 30-Minute Operating Reserve to Zero (655MW) - Voluntary Load Curtailment, 3 days/month - Public Appeals, 3 days/year 5% Remote Controlled Voltage Reduction - Emergency Assistance from External Areas - Part of the 10-Minute Operating Reserve (860 MW of 1310 MW) to Zero [April 28 ICS]
2	Special Case Resources (SCR)	SCRs sold for the program discounted to historic availability ("effective capacity"). Monthly variation based on historical experience. Summer values calculated from the latest available July registrations (July 2023 SCR enrollment) held constant for all years of study. New Method: 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	SCRs sold for the program discounted to historic availability ("effective capacity"). Monthly variation based on historical experience. Summer values calculated from the latest available July registrations (July 2024 SCR enrollment) held constant for all years of study. 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	SCRs sold for the program discounted to historic availability ("effective capacity"). Monthly variation based on historical experience. Summer values calculated from the latest available July registrations (July 2025 SCR enrollment) held constant for all years of study. 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

	Parameter	2024 RNA Base Cases Key Assumptions (2024 Gold Book)	2025 RPP, 2025 Q4 STAR Key Assumptions (2025 Gold Book)	2026 RNA Key Assumptions (2026 Gold Book)
		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] .	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] .	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.	Not modeled if the values are less than 2 MW.
4	Operating Reserves	655 MW 30-min reserve to zero 910 MW (of 1310 MW) 10-min reserve to zero 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 910 MW (of 1310 MW) 10-min reserve to zero 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 860 MW (of 1310 MW) 10-min reserve to zero Note: the 10-min reserve modeling method is updated per NYISO's recommendation at April 28, 2026 ICS to maintain (or no longer deplete/use) 450 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: 860 MW (=1,310 MW-450 MW).
5	Other EOPs (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.	Based on TO information, measured data, and NYISO forecasts. Will use 2025 elections, as available. EOP Notes: 1. Starting with the 2026 RNA, EOP Step 6 and 7 will have a 3 calls/month, 3 calls/year, respectively limit, aligning with the IRM model 2. Emergency external assistance NYCA limit change by gradually lowering it by 100 MW per study year
External Control Areas Modeling Assumptions - External models (NE, HQ, Ontario, PJM) received via the NPCC CP-8 WG process. - 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. - Load and capacity fixed through the study years. - The renewable and energy limited shapes are removed. - EOPs are not represented for the external Control Area capacity models. - External Areas adjusted to be between 0.1 and 0.15 event-days/year LOLE by adjusting capacity pro-rata in all areas. - Implemented a statewide emergency assistance (from the neighboring systems) limit of 3500 MW, decreased by 100 MW per study year starting with the 2026 RNA. - LFU is applied to neighboring systems. - Same load historical years are used as NY.				

	Parameter	2024 RNA Base Cases	2025 RPP, 2025 Q4 STAR	2026 RNA
		Key Assumptions	Key Assumptions	Key Assumptions
		(2024 Gold Book)	(2025 Gold Book)	(2026 Gold Book)
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.	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	Simplified model: The 8 ISO-NE MARS areas (bubbles) were consolidated into one starting 2020 RNA
3	HQ	Per RNA Procedure.	Per RNA Procedure.	Per RNA Procedure.
4	IESO	Per RNA procedure.	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.	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.	Implemented a statewide limit starting at 3,500 MW, decreased by 100 MW each study year. This limit is additional to the “pipe” limits.
Miscellaneous				
1	MARS Model Version	4.14.2179	5.7.3765	v5.7.3765

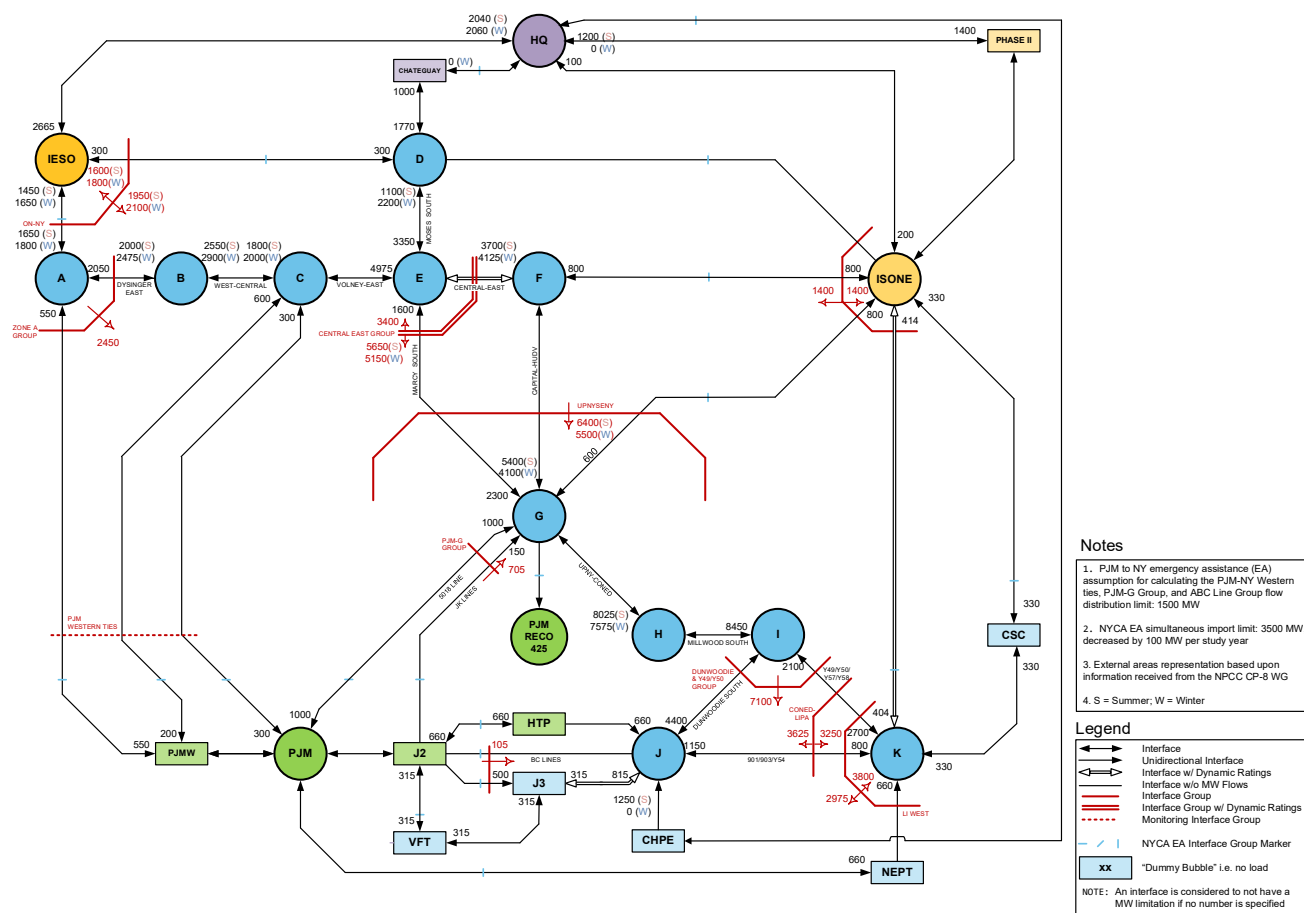
2026 Planning Topology Study Years 1-3²⁶



MARS Topology for 2026 RNA Base Cases: Study Years 1 through 3 (2027-2029)

²⁶ This is the MARS topology used for 2024 Reliability Needs Assessment studies and is not fully re-evaluated for each quarterly STAR.

Figure 26: 2026 RNA Topology Study Years 4-10 (2030-2036)



MARS Topology for 2026 RNA Base Cases: Study Years 4 through 10 (2030-2036) – with LIPPTN

Appendix E: Transmission Security Margin Assessment

Introduction

The Reliability Planning Process security analysis also includes transmission security margin analysis to identify plausible changes in conditions or assumptions that might adversely impact the reliability of the system. Transmission security margin analysis determines the ability to meet load plus losses against the generation, interchanges, and temperature-based generation derates (total resources) for a certain locality within NYCA. This assessment is performed using a deterministic approach through a spreadsheet-based method. For this assessment, transmission security margins are evaluated for the Lower Hudson Valley, New York City, and Long Island localities, and a reliability need is identified when the transmission security margin is less than zero for those localities. Transmission security margin results for time horizons beyond the time horizon of this STAR are out of scope for this assessment.

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 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 applicable study horizon.

For the transmission security margin assessment, battery storage is kept offline unless it is needed to reduce or eliminate a margin deficiency. If a margin deficiency is found without the use of battery storage, the hourly margin, which is constructed using the hourly load shapes, is examined to find the first hour with a margin deficiency. Battery storage is then dispatched for each hour with a margin deficiency, up to the maximum power (MW) rating of the batteries in the locality or until the margin deficiency is resolved, whichever comes first. Battery storage discharge is stopped when the maximum energy (MWh) rating of the batteries is reached. Depending on the duration and depth of the margin deficiencies, this can lead to battery storage fully discharging before the locality noncoincident peak hour. The locality hourly margin curve is also used to verify sufficient generation and import capability to fully charge the batteries starting at midnight on the peak day. If battery storage is unable to charge fully, its available energy will be limited in the margin calculation. Using New York City summer margin as an example, battery discharge at the locality noncoincident peak hour based on this method is shown in Figure 32 line-item Q. The 2026 RNA Transmission Security Appendix contains specific examples of this battery dispatch process.

In the Short-Term Reliability Process, the NYISO evaluates a broader range of key assumptions to manage uncertainty when evaluating generator deactivations, as described in NYISO Procedures. In evaluating the planned system, Generator Deactivation Assessments will also identify dependencies on future planned projects (a.k.a. “status quo”). Should a dependency be identified on a future planned project, the NYISO may identify a Generator Deactivation Reliability Need. When a Generator Deactivation Assessment is not performed in a STAR, the transmission security margin results for status quo and higher demand are provided for information only.

Lower Hudson Valley (Zones G-J)

The Lower Hudson Valley or southeastern New York (SENY) locality comprises Zones G through J and includes the electrical connections to the RECO load in PJM. 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. As the system changes, the limiting contingency combination may also change. Throughout the study horizon, the limiting first-level contingency is the loss of Knickerbocker – Pleasant Valley 345 kV in summer and winter.

Figure 27 through Figure 30 show the calculation of the summer and winter Lower Hudson Valley transmission security margin for baseline expected weather conditions for the noncoincident peak and higher demand forecasts with normal transfer criteria. Status Quo and As-Planned margin results are shown.

Under the baseline forecast for noncoincident summer peak demand, the Lower Hudson Valley planned system transmission security margin would be deficient starting in 2033 with the deficiency of 139 MW for two hours and growing to 1,598 MW for seven hours in 2036. Under the baseline forecast for noncoincident winter peak demand, the Lower Hudson Valley planned system transmission security margin would be sufficient throughout the study horizon.

Figure 27: Summer Peak Lower Hudson Valley Margin Calculation – Status Quo System

Lower Hudson Valley Transmission Security Margin											
Summer Peak - Status Quo System, Expected Weather, Normal Transfer Criteria (MW)											
Line	Item	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
A	G-J Noncoincident Peak Demand Forecast	(15,443)	(15,466)	(15,523)	(15,562)	(15,609)	(15,647)	(15,675)	(15,706)	(15,781)	(15,874)
B	RECO Demand	(414)	(414)	(414)	(410)	(410)	(410)	(410)	(410)	(420)	(420)
C	Total Demand (A+B)	(15,857)	(15,880)	(15,937)	(15,972)	(16,019)	(16,057)	(16,085)	(16,116)	(16,201)	(16,294)
D	UPNY-SENY Limit (4)	4,825	4,825	4,825	4,825	4,825	4,825	4,825	4,825	4,825	4,825
E	ABC PARs to J	(11)	(11)	(11)	(11)	(11)	(11)	(11)	(11)	(11)	(11)
F	K - SENY	(33)	(33)	(98)	(160)	(231)	(499)	(613)	(663)	(789)	(859)
G	Total SENY AC Import (D+E+F)	4,781	4,781	4,716	4,654	4,583	4,315	4,201	4,151	4,025	3,955
H	Loss of Source Contingency	0	0	0	0	0	0	0	0	0	0
I	Resource Need (C+G+H)	(11,076)	(11,099)	(11,221)	(11,318)	(11,436)	(11,742)	(11,884)	(11,965)	(12,176)	(12,339)
J	G-J Generation (1)	12,737	12,737	12,231	12,231	11,833	11,833	11,833	11,833	11,833	11,833
K	G-J Thermal Generation Unavailability - Aging	0	0	0	0	0	(445)	(648)	(1,038)	(1,131)	(1,720)
L	G-J Thermal Generation Unavailability - EFORd (2)	(1,358)	(1,358)	(1,317)	(1,317)	(1,285)	(1,248)	(1,231)	(1,200)	(1,192)	(1,145)
M	G-J Thermal Generation Unavailability - Extreme Temperatures	0	0	0	0	0	0	0	0	0	0
N	G-J Renewable Generation Unavailability - Dispatch Assumptions (3)	(47)	(47)	(47)	(47)	(47)	(47)	(47)	(47)	(47)	(47)
O	SCRs	0	0	0	0	0	0	0	0	0	0
P	Net ICAP External Imports (5)	1,390	1,390	1,390	1,390	1,390	1,390	1,390	1,390	1,390	1,390
Q	Total Resources Available (J+K+L+M+N+O+P)	12,721	12,721	12,256	12,256	11,890	11,483	11,296	10,938	10,852	10,311
R	Baseline Noncoincident Peak Transmission Security Margin (I+Q)	1,645	1,622	1,036	939	454	(259)	(588)	(1,027)	(1,324)	(2,027)
S	Battery Storage MW	3	3	3	3	3	3	3	3	3	3
T	Battery Storage MW Discharge at Locality Noncoincident Peak Hour (6)	0	0	0	0	1	3	3	3	3	0
U	Noncoincident Peak Transmission Security Margin with Batteries (R+T)	1,645	1,622	1,036	939	455	(256)	(585)	(1,024)	(1,321)	(2,027)
V	Higher Demand Transmission Security Margin with Batteries (7)	1,774	1,712	1,104	983	440	(374)	(804)	(1,371)	(1,847)	(2,675)

Notes:

1. Reflects the 2026 Gold Book existing summer capacity plus projected additions and deactivations.
2. Reflects derates for thermal resources based on NYCA Zonal Average EFORd.
3. Reflects the derates for renewable generation 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 (2026 Gold Book Table I-9a) and solar PV peak reductions (2026 Gold Book Table I-9c). Derates for run-of-river hydro are included.
4. Limits for 2027 through 2036 are based on summer peak 2027, 2031, and 2036 representations evaluated in the 2026 RNA.
5. Interchanges are based on ERAG MMWG values and firm transactions.
6. Consistent with established inclusion rules, battery storage will be used when needed to address a margin deficiency. When margins in line item R are negative, storage will be dispatched beginning with the first hour with a margin deficiency. If battery storage has remaining injection capability at the noncoincident peak hour, battery storage will be dispatched, as available to address the deficiency. If battery storage use at the peak hour is less than the installed MW in line item S, this indicates that by the noncoincident peak hour, storage will not have sufficient energy to discharge at maximum for the peak hour.
7. Higher demand margin calculation not shown in detail in this table.

Figure 28: Summer Peak Lower Hudson Valley Margin Calculation – Planned System

Lower Hudson Valley Transmission Security Margin											
Summer Peak - Planned System, Expected Weather, Normal Transfer Criteria (MW)											
Line	Item	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
A	G-J Noncoincident Peak Demand Forecast	(15,443)	(15,466)	(15,523)	(15,562)	(15,609)	(15,647)	(15,675)	(15,706)	(15,781)	(15,874)
B	RECO Demand	(414)	(414)	(414)	(410)	(410)	(410)	(410)	(410)	(420)	(420)
C	Total Demand (A+B)	(15,857)	(15,880)	(15,937)	(15,972)	(16,019)	(16,057)	(16,085)	(16,116)	(16,201)	(16,294)
D	UPNY-SENY Limit (4)	4,825	4,825	4,825	4,825	4,825	4,825	4,825	4,825	4,825	4,825
E	ABC PARs to J	(11)	(11)	(11)	(11)	(11)	(11)	(11)	(11)	(11)	(11)
F	K - SENY	(33)	(33)	(33)	34	(37)	(305)	(419)	(469)	(613)	(684)
G	Total SENY AC Import (D+E+F)	4,781	4,781	4,781	4,848	4,777	4,509	4,395	4,345	4,201	4,130
H	Loss of Source Contingency	0	0	0	0	0	0	0	0	0	0
I	Resource Need (C+G+H)	(11,076)	(11,099)	(11,156)	(11,124)	(11,242)	(11,548)	(11,690)	(11,771)	(12,000)	(12,164)
J	G-J Generation (1)	12,852	13,767	13,262	13,262	12,864	12,864	12,864	12,864	12,864	12,864
K	G-J Thermal Generation Unavailability - Aging	0	0	0	0	0	(445)	(648)	(1,038)	(1,131)	(1,720)
L	G-J Thermal Generation Unavailability - EFORd (2)	(1,358)	(1,358)	(1,317)	(1,317)	(1,285)	(1,248)	(1,231)	(1,200)	(1,192)	(1,145)
M	G-J Thermal Generation Unavailability - Extreme Temperatures	0	0	0	0	0	0	0	0	0	0
N	G-J Renewable Generation Unavailability - Dispatch Assumptions (3)	(162)	(983)	(983)	(983)	(983)	(983)	(991)	(991)	(991)	(991)
O	SCRs	0	0	0	0	0	0	0	0	0	0
P	Net ICAP External Imports (5)	1,390	1,390	1,390	1,390	1,390	1,390	1,390	1,390	1,390	1,390
Q	Total Resources Available (J+K+L+M+N+O+P)	12,721	12,816	12,351	12,351	11,985	11,578	11,383	11,025	10,939	10,398
R	Baseline Noncoincident Peak Transmission Security Margin (I+Q)	1,645	1,717	1,195	1,227	743	30	(307)	(746)	(1,061)	(1,766)
S	Battery Storage MW	118	168	168	168	168	168	168	168	168	168
T	Battery Storage MW Discharge at Locality Noncoincident Peak Hour (6)	0	0	0	0	0	0	168	168	168	168
U	Noncoincident Peak Transmission Security Margin with Batteries (R+T)	1,645	1,717	1,195	1,227	743	30	(139)	(578)	(893)	(1,598)
V	Higher Demand Transmission Security Margin with Batteries (7)	1,774	1,799	1,204	1,263	717	1	(358)	(1,089)	(1,585)	(2,415)

Notes:

1. Reflects the 2026 Gold Book existing summer capacity plus projected additions and deactivations.
2. Reflects derates for thermal resources based on NYCA Zonal Average EFORd.
3. Reflects the derates for renewable generation 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 (2026 Gold Book Table I-9a) and solar PV peak reductions (2026 Gold Book Table I-9c). Derates for run-of-river hydro are included.
4. Limits for 2027 through 2036 are based on summer peak 2027, 2031, and 2036 representations evaluated in the 2026 RNA.
5. Interchanges are based on ERAG MMWG values and firm transactions.
6. Consistent with established inclusion rules, battery storage will be used when needed to address a margin deficiency. When margins in line item R are negative, storage will be dispatched beginning with the first hour with a margin deficiency. If battery storage has remaining injection capability at the noncoincident peak hour, battery storage will be dispatched, as available to address the deficiency. If battery storage use at the peak hour is less than the installed MW in line item S, this indicates that by the noncoincident peak hour, storage will not have sufficient energy to discharge at maximum for the peak hour.
7. Higher demand margin calculation not shown in detail in this table.

Figure 29: Winter Peak Lower Hudson Valley Margin Calculation – Status Quo System

Lower Hudson Valley Transmission Security Margin											
Winter Peak - Status Quo System, Expected Weather, Normal Transfer Criteria (MW)											
Line	Item	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
A	G-J Noncoincident Peak Demand Forecast	(11,003)	(11,114)	(11,234)	(11,391)	(11,539)	(11,705)	(11,850)	(12,024)	(12,240)	(12,499)
B	RECO Demand	(253)	(253)	(253)	(273)	(273)	(273)	(273)	(273)	(305)	(305)
C	Total Demand (A+B)	(11,256)	(11,367)	(11,487)	(11,664)	(11,812)	(11,978)	(12,123)	(12,297)	(12,545)	(12,804)
D	UPNY-SENY Limit (4)	4,900	4,900	4,900	4,900	4,900	4,900	4,900	4,900	4,900	4,900
E	ABC PARs to J	(11)	(11)	(11)	(11)	(11)	(11)	(11)	(11)	(11)	(11)
F	K - SENY	(33)	(33)	(33)	(33)	(33)	(33)	(33)	(33)	(33)	(33)
G	Total SENY AC Import (D+E+F)	4,856	4,856	4,856	4,856	4,856	4,856	4,856	4,856	4,856	4,856
H	Loss of Source Contingency	0	0	0	0	0	0	0	0	0	0
I	Resource Need (C+G+H)	(6,400)	(6,511)	(6,631)	(6,808)	(6,956)	(7,122)	(7,267)	(7,441)	(7,689)	(7,948)
J	G-J Generation (1)	13,650	13,650	12,998	12,587	12,587	12,587	12,587	12,587	12,587	12,587
K	G-J Thermal Generation Unavailability - Unavailability of Non-Firm Gas (6)	(2,141)	(2,141)	(2,141)	(1,730)	(1,730)	(1,730)	(1,730)	(1,730)	(1,730)	(1,730)
L	G-J Thermal Generation Unavailability - Aging	0	0	0	0	0	(276)	(459)	(834)	(909)	(1,475)
M	G-J Thermal Generation Unavailability - EFORd (2)	(1,274)	(1,274)	(1,222)	(1,222)	(1,222)	(1,197)	(1,182)	(1,152)	(1,146)	(1,100)
N	G-J Renewable Generation Unavailability - Dispatch Assumptions (3)	(39)	(39)	(39)	(39)	(39)	(39)	(39)	(39)	(39)	(39)
O	SCRs	0	0	0	0	0	0	0	0	0	0
P	Net ICAP External Imports (5)	140	140	140	140	140	140	140	140	140	140
Q	Total Resources Available (J+K+L+M+N+O+P)	10,336	10,336	9,736	9,736	9,736	9,484	9,317	8,972	8,903	8,383
R	Baseline Noncoincident Peak Transmission Security Margin (I+Q)	3,936	3,825	3,105	2,928	2,780	2,362	2,050	1,531	1,214	435
S	Battery Storage MW	3	3	3	3	3	3	3	3	3	3
T	Battery Storage MW Discharge at Locality Noncoincident Peak Hour (7)	0	0	0	0	0	0	0	0	0	0
U	Noncoincident Peak Transmission Security Margin with Batteries (R+T)	3,936	3,825	3,105	2,928	2,780	2,362	2,050	1,531	1,214	435
V	Higher Demand Transmission Security Margin with Batteries (8)	3,809	3,674	2,790	2,552	2,387	1,890	1,465	826	313	(607)

Notes:

1. Reflects the 2026 Gold Book existing winter capacity plus projected additions and deactivations.
2. Reflects derates for thermal resources based on NYCA Zonal Average EFORd.
3. 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.
4. Limits for 2027 through 2036 are based on winter peak 2027, 2031, and 2036 representations evaluated in the 2026 RNA.
5. Interchanges are based on ERAG MMWG values and firm transactions.
6. Unavailability of non-firm gas is modeled per NYSRC Reliability Rule B.1 R1.1 which includes consideration for generation availability including limitations related to weather conditions (e.g. non-firm gas generation unavailability during winter peak). This assessment models all gas only units that do not have a firm gas contract as unavailable and other adjustment to generation assumptions.
7. Consistent with established inclusion rules, battery storage will be used when needed to address a margin deficiency. When margins in line item R are negative, storage will be dispatched beginning with the first hour with a margin deficiency. If battery storage has remaining injection capability at the noncoincident peak hour, battery storage will be dispatched, as available to address the deficiency. If battery storage use at the peak hour is less than the installed MW in line item S, this indicates that by the noncoincident peak hour, storage will not have sufficient energy to discharge at maximum for the peak hour.
8. Higher demand margin calculation not shown in detail in this table.

Figure 30: Winter Peak Lower Hudson Valley Margin Calculation – Planned System

Lower Hudson Valley Transmission Security Margin											
Winter Peak - Planned System, Expected Weather, Normal Transfer Criteria (MW)											
Line	Item	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
A	G-J Noncoincident Peak Demand Forecast	(11,003)	(11,114)	(11,234)	(11,391)	(11,539)	(11,705)	(11,850)	(12,024)	(12,240)	(12,499)
B	RECO Demand	(253)	(253)	(253)	(273)	(273)	(273)	(273)	(273)	(305)	(305)
C	Total Demand (A+B)	(11,256)	(11,367)	(11,487)	(11,664)	(11,812)	(11,978)	(12,123)	(12,297)	(12,545)	(12,804)
D	UPNY-SENY Limit (4)	4,900	4,900	4,900	4,900	4,900	4,900	4,900	4,900	4,900	4,900
E	ABC PARs to J	(11)	(11)	(11)	(11)	(11)	(11)	(11)	(11)	(11)	(11)
F	K - SENY	(33)	(33)	(33)	1,700	1,694	1,347	1,229	1,115	894	735
G	Total SENY AC Import (D+E+F)	4,856	4,856	4,856	6,589	6,583	6,236	6,118	6,004	5,783	5,624
H	Loss of Source Contingency	0	0	0	0	0	0	0	0	0	0
I	Resource Need (C+G+H)	(6,400)	(6,511)	(6,631)	(5,075)	(5,229)	(5,742)	(6,005)	(6,293)	(6,762)	(7,180)
J	G-J Generation (1)	14,681	14,681	14,029	13,618	13,618	13,618	13,618	13,618	13,618	13,618
K	G-J Thermal Generation Unavailability - Unavailability of Non-Firm Gas (6)	(2,141)	(2,141)	(2,141)	(1,730)	(1,730)	(1,730)	(1,730)	(1,730)	(1,730)	(1,730)
L	G-J Thermal Generation Unavailability - Aging	0	0	0	0	0	(276)	(459)	(834)	(909)	(1,475)
M	G-J Thermal Generation Unavailability - EFORD (2)	(1,274)	(1,274)	(1,222)	(1,222)	(1,222)	(1,197)	(1,182)	(1,152)	(1,146)	(1,100)
N	G-J Renewable Generation Unavailability - Dispatch Assumptions (3)	(907)	(907)	(907)	(907)	(907)	(907)	(907)	(907)	(907)	(907)
O	SCRs	0	0	0	0	0	0	0	0	0	0
P	Net ICAP External Imports (5)	140	140	140	140	140	140	140	140	140	140
Q	Total Resources Available (J+K+L+M+N+O+P)	10,499	10,499	9,899	9,899	9,899	9,648	9,480	9,135	9,066	8,546
R	Baseline Noncoincident Peak Transmission Security Margin (I+Q)	4,099	3,988	3,268	4,824	4,671	3,906	3,475	2,842	2,305	1,366
S	Battery Storage MW	168	168	168	168	168	168	168	168	168	168
T	Battery Storage MW Discharge at Locality Noncoincident Peak Hour (7)	0	0	0	0	0	0	0	0	0	0
U	Noncoincident Peak Transmission Security Margin with Batteries (R+T)	4,099	3,988	3,268	4,824	4,671	3,906	3,475	2,842	2,305	1,366
V	Higher Demand Transmission Security Margin with Batteries (8)	3,972	3,837	2,953	4,448	4,278	3,434	2,890	2,137	1,404	321

Notes:

1. Reflects the 2026 Gold Book existing winter capacity plus projected additions and deactivations.
2. Reflects derates for thermal resources based on NYCA Zonal Average EFORD.
3. 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.
4. Limits for 2027 through 2036 are based on winter peak 2027, 2031, and 2036 representations evaluated in the 2026 RNA.
5. Interchanges are based on ERAG MMWG values and firm transactions.
6. Unavailability of non-firm gas is modeled per NYSRC Reliability Rule B.1 R1.1 which includes consideration for generation availability including limitations related to weather conditions (e.g. non-firm gas generation unavailability during winter peak). This assessment models all gas only units that do not have a firm gas contract as unavailable and other adjustment to generation assumptions.
7. Consistent with established inclusion rules, battery storage will be used when needed to address a margin deficiency. When margins in line item R are negative, storage will be dispatched beginning with the first hour with a margin deficiency. If battery storage has remaining injection capability at the noncoincident peak hour, battery storage will be dispatched, as available to address the deficiency. If battery storage use at the peak hour is less than the installed MW in line item S, this indicates that by the noncoincident peak hour, storage will not have sufficient energy to discharge at maximum for the peak hour.
8. Higher demand margin calculation not shown in detail in this table.

New York City (Zone J)

The New York City locality comprises Zone J and is served by Con Edison. Within this 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).²⁷ 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.

In summer 2026 and continuing throughout the study period, the limiting contingency combination is loss of the CHPE HVDC cable followed by the loss of Ravenswood 3. In winter 2026-2027 and continuing throughout the study period, the limiting contingency combination is loss of Ravenswood 3 followed by the loss of Dunwoodie – Mott Haven (72). The CHPE cable is not included in limiting contingencies in winter due to the assumption that it is scheduled at 0 MW for the winter seasons.

Figure 31 through Figure 34 shows the calculation of the New York City transmission security margin with the noncoincident peak and higher demand forecasts for baseline expected weather for summer with normal transfer criteria. Status Quo and As-Planned margin results are shown.

Under the baseline forecast for noncoincident summer peak demand, the New York City transmission security margin would be deficient starting in 2032 with the deficiency of 396 MW for seven hours and growing to 1,864 MW for fifteen hours in 2036. Under the baseline forecast for noncoincident winter peak demand, the New York City transmission security margin would be deficient starting in 2036 with a deficiency of 794 MW for sixteen hours.

²⁷ [Con Edison, TP-7100-18 Transmission Planning Criteria, dated August 2019.](#)

Figure 31: Summer Peak New York City Transmission Security Margin Calculation – Status Quo System

New York City Transmission Security Margin											
Summer Peak - Status Quo System, Expected Weather, Normal Transfer Criteria (MW)											
	Item	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
A	Zone J Noncoincident Peak Demand Forecast	(11,100)	(11,120)	(11,140)	(11,170)	(11,200)	(11,230)	(11,250)	(11,270)	(11,320)	(11,380)
B	I+K to J (4)	4,725	4,725	4,725	4,725	4,725	4,725	4,725	4,725	4,725	4,725
C	ABC PARs to J	(11)	(11)	(11)	(11)	(11)	(11)	(11)	(11)	(11)	(11)
D	Total J AC Import (B+C)	4,714	4,714	4,714	4,714	4,714	4,714	4,714	4,714	4,714	4,714
E	Loss of Source Contingency	(2,238)	(2,238)	(2,238)	(2,238)	(2,238)	(2,238)	(2,238)	(2,238)	(2,238)	(2,238)
F	Resource Need (A+D+E)	(8,624)	(8,644)	(8,664)	(8,694)	(8,724)	(8,754)	(8,774)	(8,794)	(8,844)	(8,904)
G	J Generation (1)	8,540	8,540	8,034	8,034	7,636	7,636	7,636	7,636	7,636	7,636
H	J Thermal Generation Unavailability - Aging	0	0	0	0	0	(423)	(624)	(1,011)	(1,102)	(1,688)
I	J Thermal Generation Unavailability - EFORD (2)	(688)	(688)	(647)	(647)	(615)	(581)	(565)	(534)	(526)	(479)
J	J Thermal Generation Unavailability - Extreme Temperatures	0	0	0	0	0	0	0	0	0	0
K	J Renewable Generation Unavailability - Dispatch Assumptions (3)	0	0	0	0	0	0	0	0	0	0
L	SCRs	0	0	0	0	0	0	0	0	0	0
M	Net ICAP External Imports (5)	1,390	1,390	1,390	1,390	1,390	1,390	1,390	1,390	1,390	1,390
N	Total Resources Available (G+H+I+J+K+L+M)	9,242	9,242	8,777	8,777	8,411	8,022	7,837	7,481	7,397	6,859
O	Noncoincident Peak Transmission Security Margin (F+N)	618	598	113	83	(313)	(732)	(937)	(1,313)	(1,447)	(2,045)
P	Battery Storage MW	0	0	0	0	0	0	0	0	0	0
Q	Battery Storage MW Discharge at Locality Noncoincident Peak Hour (6)	0	0	0	0	0	0	0	0	0	0
R	Noncoincident Peak Transmission Security Margin with Batteries (O+Q)	618	598	113	83	(313)	(732)	(937)	(1,313)	(1,447)	(2,045)
S	Higher Demand Transmission Security Margin with Batteries (7)	758	708	163	113	(313)	(802)	(1,127)	(1,603)	(1,877)	(2,575)

Notes:

1. Reflects the 2026 Gold Book existing summer capacity plus projected additions and deactivations.
2. Reflects derates for thermal resources based on Zonal Average EFORD.
3. Reflects the derates for renewable generation 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 (2026 Gold Book Table I-9a) and solar PV peak reductions (2026 Gold Book Table I-9c). This portion of the margin calculation assumes storage is offline. See later section for storage details.
4. Limits for 2027 through 2036 are based on summer peak 2027 representations evaluated in the 2026 RNA.
5. Interchanges are based on ERAG MMWG values and firm transactions.
6. Consistent with established inclusion rules, battery storage will be used when needed to address a margin deficiency. When margins in line item O are negative, storage will be dispatched beginning with the first hour with a margin deficiency. If battery storage has remaining injection capability at the noncoincident peak hour, battery storage will be dispatched, as available to address the deficiency. If battery storage use at the peak hour is less than the installed MW in line item P, this indicates that by the noncoincident peak hour, storage will not have sufficient energy to discharge at maximum for the peak hour.
7. Higher demand margin calculation not shown in detail in this table.

Figure 32: Summer Peak New York City Transmission Security Margin Calculation – Planned System

New York City Transmission Security Margin											
Summer Peak - Planned System, Expected Weather, Normal Transfer Criteria (MW)											
	Item	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
A	Zone J Noncoincident Peak Demand Forecast	(11,100)	(11,120)	(11,140)	(11,170)	(11,200)	(11,230)	(11,250)	(11,270)	(11,320)	(11,380)
B	I+K to J (4)	4,725	4,725	4,725	4,825	4,825	4,825	4,825	4,825	4,825	4,825
C	ABC PARs to J	(11)	(11)	(11)	(11)	(11)	(11)	(11)	(11)	(11)	(11)
D	Total J AC Import (B+C)	4,714	4,714	4,714	4,814	4,814	4,814	4,814	4,814	4,814	4,814
E	Loss of Source Contingency	(2,238)	(2,238)	(2,238)	(2,238)	(2,238)	(2,238)	(2,238)	(2,238)	(2,238)	(2,238)
F	Resource Need (A+D+E)	(8,624)	(8,644)	(8,664)	(8,594)	(8,624)	(8,654)	(8,674)	(8,694)	(8,744)	(8,804)
G	J Generation (1)	8,655	9,521	9,015	9,015	8,617	8,617	8,617	8,617	8,617	8,617
H	J Thermal Generation Unavailability - Aging	0	0	0	0	0	(423)	(624)	(1,011)	(1,102)	(1,688)
I	J Thermal Generation Unavailability - EFORd (2)	(688)	(688)	(647)	(647)	(615)	(581)	(565)	(534)	(526)	(479)
J	J Thermal Generation Unavailability - Extreme Temperatures	0	0	0	0	0	0	0	0	0	0
K	J Renewable Generation Unavailability - Dispatch Assumptions (3)	(115)	(899)	(899)	(899)	(899)	(899)	(899)	(899)	(899)	(899)
L	SCRs	0	0	0	0	0	0	0	0	0	0
M	Net ICAP External Imports (5)	1,390	1,390	1,390	1,390	1,390	1,390	1,390	1,390	1,390	1,390
N	Total Resources Available (G+H+I+J+K+L+M)	9,242	9,324	8,859	8,859	8,493	8,103	7,919	7,562	7,479	6,940
O	Noncoincident Peak Transmission Security Margin (F+N)	618	680	195	265	(131)	(551)	(755)	(1,132)	(1,265)	(1,864)
P	Battery Storage MW	115	165	165	165	165	165	165	165	165	165
Q	Battery Storage MW Discharge at Locality Noncoincident Peak Hour (6)	0	0	0	0	132	155	0	0	0	0
R	Noncoincident Peak Transmission Security Margin with Batteries (O+Q)	618	680	195	265	0	(396)	(755)	(1,132)	(1,265)	(1,864)
S	Higher Demand Transmission Security Margin with Batteries (7)	758	790	245	295	(131)	(621)	(945)	(1,422)	(1,695)	(2,394)

Notes:

1. Reflects the 2026 Gold Book existing summer capacity plus projected additions and deactivations.
2. Reflects derates for thermal resources based on Zonal Average EFORd.
3. Reflects the derates for renewable generation 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 (2026 Gold Book Table I-9a) and solar PV peak reductions (2026 Gold Book Table I-9c). This portion of the margin calculation assumes storage is offline. See later section for storage details.
4. Limits for 2027 through 2029 are based on summer peak 2027 representations evaluated in the 2026 RNA. Limits for 2030 through 2036 are based on summer peak 2031 and 2036 representations evaluated in the 2026 RNA.
5. Interchanges are based on ERAG MMWG values and firm transactions.
6. Consistent with established inclusion rules, battery storage will be used when needed to address a margin deficiency. When margins in line item O are negative, storage will be dispatched beginning with the first hour with a margin deficiency. If battery storage has remaining injection capability at the noncoincident peak hour, battery storage will be dispatched, as available to address the deficiency. If battery storage use at the peak hour is less than the installed MW in line item P, this indicates that by the noncoincident peak hour, storage will not have sufficient energy to discharge at maximum for the peak hour.
7. Higher demand margin calculation not shown in detail in this table.

Figure 33: Winter Peak New York City Transmission Security Margin Calculation – Status Quo System

New York City Transmission Security Margin											
Winter Peak - Status Quo System, Expected Weather, Normal Transfer Criteria (MW)											
	Item	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
A	Zone J Noncoincident Peak Demand Forecast	(7,750)	(7,800)	(7,860)	(7,960)	(8,050)	(8,160)	(8,260)	(8,380)	(8,520)	(8,690)
B	I+K to J (4)	3,800	3,800	3,800	3,800	3,800	3,800	3,800	3,800	3,800	3,800
C	ABC PARs to J	(11)	(11)	(11)	(11)	(11)	(11)	(11)	(11)	(11)	(11)
D	Total J AC Import (B+C)	3,789	3,789	3,789	3,789	3,789	3,789	3,789	3,789	3,789	3,789
E	Loss of Source Contingency	(977)	(977)	(977)	(977)	(977)	(977)	(977)	(977)	(977)	(977)
F	Resource Need (A+D+E)	(4,938)	(4,988)	(5,048)	(5,148)	(5,238)	(5,348)	(5,448)	(5,568)	(5,708)	(5,878)
G	J Generation (1)	9,274	9,274	8,622	8,211	8,211	8,211	8,211	8,211	8,211	8,211
H	J Thermal Generation Unavailability - Unavailability of Non-Firm Gas (6)	(2,062)	(2,062)	(2,062)	(1,650)	(1,650)	(1,650)	(1,650)	(1,650)	(1,650)	(1,650)
I	J Thermal Generation Unavailability - Aging	0	0	0	0	0	(249)	(428)	(801)	(872)	(1,435)
J	J Thermal Generation Unavailability - EFORD (2)	(587)	(587)	(535)	(535)	(535)	(515)	(500)	(470)	(465)	(419)
K	J Renewable Generation Unavailability - Dispatch Assumptions (3)	0	0	0	0	0	0	0	0	0	0
L	SCRs	0	0	0	0	0	0	0	0	0	0
M	Net ICAP External Imports (5)	140	140	140	140	140	140	140	140	140	140
N	Total Resources Available (G+H+I+J+K+L+M)	6,765	6,765	6,166	6,166	6,166	5,936	5,772	5,430	5,364	4,846
O	Noncoincident Peak Transmission Security Margin (F+N)	1,828	1,778	1,118	1,018	928	589	324	(138)	(344)	(1,032)
P	Battery Storage MW	165	165	165	165	165	165	165	165	165	165
Q	Battery Storage MW Discharge at Locality Noncoincident Peak Hour (7)	0	0	0	0	0	0	0	0	107	0
R	Noncoincident Peak Transmission Security Margin with Batteries (O+Q)	1,828	1,778	1,118	1,018	928	589	324	(138)	(237)	(1,032)
S	Higher Demand Transmission Security Margin with Batteries (8)	1,748	1,698	908	788	678	279	(76)	(588)	(954)	(1,712)

Notes:

1. Reflects the 2026 Gold Book existing winter capacity plus projected additions and deactivations.
2. Reflects derates for thermal resources based on NYCA Zonal Average EFORD.
3. 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.
4. Limits for 2027 through 2036 are based on winter peak 2027 representations evaluated in the 2026 RNA.
5. Interchanges are based on ERAG MMWG values and firm transactions.
6. Unavailability of non-firm gas is modeled per NYSRC Reliability Rule B.1 R1.1 which includes consideration for generation availability including limitations related to weather conditions (e.g. non-firm gas generation unavailability during winter peak). This assessment models all gas only units that do not have a firm gas contract as unavailable and other adjustment to generation assumptions.
7. Consistent with established inclusion rules, battery storage will be used when needed to address a margin deficiency. When margins in line item O are negative, storage will be dispatched beginning with the first hour with a margin deficiency. If battery storage has remaining injection capability at the noncoincident peak hour, battery storage will be dispatched, as available to address the deficiency. If battery storage use at the peak hour is less than the installed MW in line item P, this indicates that by the noncoincident peak hour, storage will not have sufficient energy to discharge at maximum for the peak hour.
8. Higher demand margin calculation not shown in detail in this table.

Figure 34: Winter Peak New York City Transmission Security Margin Calculation – Planned System

New York City Transmission Security Margin											
Winter Peak - Planned System, Expected Weather, Normal Transfer Criteria (MW)											
	Item	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
A	Zone J Noncoincident Peak Demand Forecast	(7,750)	(7,800)	(7,860)	(7,960)	(8,050)	(8,160)	(8,260)	(8,380)	(8,520)	(8,690)
B	I+K to J (4)	3,800	3,800	3,800	3,875	3,875	3,875	3,875	3,875	3,875	3,875
C	ABC PARs to J	(11)	(11)	(11)	(11)	(11)	(11)	(11)	(11)	(11)	(11)
D	Total J AC Import (B+C)	3,789	3,789	3,789	3,864	3,864	3,864	3,864	3,864	3,864	3,864
E	Loss of Source Contingency	(977)	(977)	(977)	(977)	(977)	(977)	(977)	(977)	(977)	(977)
F	Resource Need (A+D+E)	(4,938)	(4,988)	(5,048)	(5,073)	(5,163)	(5,273)	(5,373)	(5,493)	(5,633)	(5,803)
G	J Generation (1)	10,255	10,255	9,603	9,192	9,192	9,192	9,192	9,192	9,192	9,192
H	J Thermal Generation Unavailability - Unavailability of Non-Firm Gas (6)	(2,062)	(2,062)	(2,062)	(1,650)	(1,650)	(1,650)	(1,650)	(1,650)	(1,650)	(1,650)
I	J Thermal Generation Unavailability - Aging	0	0	0	0	0	(249)	(428)	(801)	(872)	(1,435)
J	J Thermal Generation Unavailability - EFORD (2)	(587)	(587)	(535)	(535)	(535)	(515)	(500)	(470)	(465)	(419)
K	J Renewable Generation Unavailability - Dispatch Assumptions (3)	(818)	(818)	(818)	(818)	(818)	(818)	(818)	(818)	(818)	(818)
L	SCRs	0	0	0	0	0	0	0	0	0	0
M	Net ICAP External Imports (5)	140	140	140	140	140	140	140	140	140	140
N	Total Resources Available (G+H+I+J+K+L+M)	6,929	6,929	6,329	6,329	6,329	6,100	5,935	5,593	5,527	5,009
O	Noncoincident Peak Transmission Security Margin (F+N)	1,991	1,941	1,281	1,256	1,166	827	562	100	(106)	(794)
P	Battery Storage MW	165	165	165	165	165	165	165	165	165	165
Q	Battery Storage MW Discharge at Locality Noncoincident Peak Hour (7)	0	0	0	0	0	0	0	0	107	0
R	Noncoincident Peak Transmission Security Margin with Batteries (O+Q)	1,991	1,941	1,281	1,256	1,166	827	562	100	1	(794)
S	Higher Demand Transmission Security Margin with Batteries (8)	1,911	1,861	1,071	1,026	916	517	162	(185)	(716)	(1,474)

Notes:

1. Reflects the 2026 Gold Book existing winter capacity plus projected additions and deactivations.
2. Reflects derates for thermal resources based on NYCA Zonal Average EFORD.
3. 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.
4. Limits for 2027 through 2029 are based on winter peak 2027 representations evaluated in the 2026 RNA. Limits for 2030 through 2036 are based on winter peak 2031 representations evaluated in the 2026 RNA.
5. Interchanges are based on ERAG MMWG values and firm transactions.
6. Unavailability of non-firm gas is modeled per NYSRC Reliability Rule B.1 R1.1 which includes consideration for generation availability including limitations related to weather conditions (e.g. non-firm gas generation unavailability during winter peak). This assessment models all gas only units that do not have a firm gas contract as unavailable and other adjustment to generation assumptions.
7. Consistent with established inclusion rules, battery storage will be used when needed to address a margin deficiency. When margins in line item O are negative, storage will be dispatched beginning with the first hour with a margin deficiency. If battery storage has remaining injection capability at the noncoincident peak hour, battery storage will be dispatched, as available to address the deficiency. If battery storage use at the peak hour is less than the installed MW in line item P, this indicates that by the noncoincident peak hour, storage will not have sufficient energy to discharge at maximum for the peak hour.
8. Higher demand margin calculation not shown in detail in this table.

Long Island (Zone K)

The Long Island locality comprises Zone K and is served by PSEG Long Island. Within this 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 2025 through summer 2029, the most limiting first-level contingency is the loss of the Neptune HVDC cable. From summer 2030 onward, after the Propel NY Energy transmission project is in service, the limiting first-level contingency remains the loss of the Neptune HVDC cable while the limit increases significantly. For winter 2025-2026 through winter 2029-2030, the most limiting first-level contingency is the loss of the Y49 cable. From winter 2030-2031 onward, after the Propel NY Energy transmission project is in service, the limiting first-level contingency changes to the loss of the Neptune HVDC cable.

Figure 35 through Figure show the calculation of the summer and winter Long Island transmission security margin with the noncoincident peak and higher demand forecasts for baseline expected weather with normal transfer criteria. Status Quo and As-Planned margin results are shown. Long Island maintains positive transmission security margins for the planned system throughout the study horizon. Significant increases in transmission security margins for the planned system are seen after the Propel NY Energy transmission project is placed in service.

Figure 35: Summer Peak Long Island Margin Calculation – Status Quo System

Long Island Transmission Security Margin											
Summer Peak - Status Quo System, Expected Weather, Normal Transfer Criteria (MW)											
Line	Item	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
A	Zone K Noncoincident Peak Demand Forecast	(5,136)	(5,161)	(5,200)	(5,252)	(5,310)	(5,357)	(5,392)	(5,416)	(5,438)	(5,462)
B	I+J to K (4)	950	950	950	950	950	950	950	950	950	950
C	New England Import (NNC)	0	0	0	0	0	0	0	0	0	0
D	Total K AC Import (B+C)	950	950	950	950	950	950	950	950	950	950
E	Loss of Source Contingency	(660)	(660)	(660)	(660)	(660)	(660)	(660)	(660)	(660)	(660)
F	Resource Need (A+D+E)	(4,846)	(4,871)	(4,910)	(4,962)	(5,020)	(5,067)	(5,102)	(5,126)	(5,148)	(5,172)
G	K Generation (1)	4,808	4,808	4,808	4,808	4,763	4,763	4,763	4,763	4,763	4,763
H	K Thermal Generation Unavailability - Aging	0	0	0	0	0	(272)	(307)	(340)	(465)	(526)
I	K Thermal Generation Unavailability - EFORd (2)	(566)	(566)	(566)	(566)	(561)	(527)	(523)	(519)	(504)	(496)
J	K Thermal Generation Unavailability - Extreme Temperatures	0	0	0	0	0	0	0	0	0	0
K	K Renewable Generation Unavailability - Dispatch Assumptions (3)	(159)	(159)	(167)	(167)	(167)	(167)	(167)	(167)	(167)	(167)
L	SCRs	0	0	0	0	0	0	0	0	0	0
M	Net ICAP External Imports (5)	990	990	990	990	990	990	990	990	990	990
N	Total Resources Available (G+H+I+J+K+L+M)	5,073	5,073	5,064	5,064	5,025	4,786	4,755	4,726	4,617	4,563
O	Noncoincident Peak Transmission Security Margin (F+N)	227	202	154	102	5	(281)	(347)	(400)	(531)	(609)
P	Battery Storage MW	0	0	0	0	0	0	0	0	0	0
Q	Battery Storage MWh Used on Locality Noncoincident Peak Day (6)	0	0	0	0	0	0	0	0	0	0
R	Noncoincident Peak Transmission Security Margin with Batteries (O+Q)	227	202	154	102	5	(281)	(347)	(400)	(531)	(609)
S	Higher Demand Transmission Security Margin with Batteries (7)	300	268	228	151	35	(271)	(373)	(454)	(638)	(725)

Notes:

1. Reflects the 2026 Gold Book existing summer capacity plus projected additions and deactivations.
2. Reflects derates for thermal resources based on NYCA Zonal Average EFORd.
3. Reflects the derates for renewable generation 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 (2026 Gold Book Table I-9a) and solar PV peak reductions (2026 Gold Book Table I-9c).
4. Limits for 2027 through 2036 are based on the 2025 LIPA Summer Operating Study.
5. Interchanges are based on ERAG MMWG values and firm transactions.
6. Consistent with established inclusion rules, battery storage will be used when needed to address a margin deficiency. When margins in line item O are negative, storage will be dispatched beginning with the first hour with a margin deficiency. If battery storage has remaining injection capability at the noncoincident peak hour, battery storage will be dispatched, as available to address the deficiency. If battery storage use at the peak hour is less than the installed MW in line item P, this indicates that by the noncoincident peak hour, storage will not have sufficient energy to discharge at maximum for the peak hour.
7. Higher demand margin calculation not shown in detail in this table.

Figure 36: Summer Peak Long Island Margin Calculation – Planned System

Long Island Transmission Security Margin											
Summer Peak - Status Quo System, Expected Weather, Normal Transfer Criteria (MW)											
Line	Item	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
A	Zone K Noncoincident Peak Demand Forecast	(5,136)	(5,161)	(5,200)	(5,252)	(5,310)	(5,357)	(5,392)	(5,416)	(5,438)	(5,462)
B	I+J to K (4)	950	950	950	950	950	950	950	950	950	950
C	New England Import (NNC)	0	0	0	0	0	0	0	0	0	0
D	Total K AC Import (B+C)	950	950	950	950	950	950	950	950	950	950
E	Loss of Source Contingency	(660)	(660)	(660)	(660)	(660)	(660)	(660)	(660)	(660)	(660)
F	Resource Need (A+D+E)	(4,846)	(4,871)	(4,910)	(4,962)	(5,020)	(5,067)	(5,102)	(5,126)	(5,148)	(5,172)
G	K Generation (1)	4,808	4,808	4,808	4,808	4,763	4,763	4,763	4,763	4,763	4,763
H	K Thermal Generation Unavailability - Aging	0	0	0	0	0	(272)	(307)	(340)	(465)	(526)
I	K Thermal Generation Unavailability - EFORD (2)	(566)	(566)	(566)	(566)	(561)	(527)	(523)	(519)	(504)	(496)
J	K Thermal Generation Unavailability - Extreme Temperatures	0	0	0	0	0	0	0	0	0	0
K	K Renewable Generation Unavailability - Dispatch Assumptions (3)	(159)	(159)	(167)	(167)	(167)	(167)	(167)	(167)	(167)	(167)
L	SCRs	0	0	0	0	0	0	0	0	0	0
M	Net ICAP External Imports (5)	990	990	990	990	990	990	990	990	990	990
N	Total Resources Available (G+H+I+J+K+L+M)	5,073	5,073	5,064	5,064	5,025	4,786	4,755	4,726	4,617	4,563
O	Noncoincident Peak Transmission Security Margin (F+N)	227	202	154	102	5	(281)	(347)	(400)	(531)	(609)
P	Battery Storage MW	0	0	0	0	0	0	0	0	0	0
Q	Battery Storage MWh Used on Locality Noncoincident Peak Day (6)	0	0	0	0	0	0	0	0	0	0
R	Noncoincident Peak Transmission Security Margin with Batteries (O+Q)	227	202	154	102	5	(281)	(347)	(400)	(531)	(609)
S	Higher Demand Transmission Security Margin with Batteries (7)	300	268	228	151	35	(271)	(373)	(454)	(638)	(725)

Notes:

1. Reflects the 2026 Gold Book existing summer capacity plus projected additions and deactivations.
2. Reflects derates for thermal resources based on NYCA Zonal Average EFORD.
3. Reflects the derates for renewable generation 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 (2026 Gold Book Table I-9a) and solar PV peak reductions (2026 Gold Book Table I-9c).
4. Limits for 2027 through 2036 are based on the 2025 LIPA Summer Operating Study.
5. Interchanges are based on ERAG MMWG values and firm transactions.
6. Consistent with established inclusion rules, battery storage will be used when needed to address a margin deficiency. When margins in line item O are negative, storage will be dispatched beginning with the first hour with a margin deficiency. If battery storage has remaining injection capability at the noncoincident peak hour, battery storage will be dispatched, as available to address the deficiency. If battery storage use at the peak hour is less than the installed MW in line item P, this indicates that by the noncoincident peak hour, storage will not have sufficient energy to discharge at maximum for the peak hour.
7. Higher demand margin calculation not shown in detail in this table.

Figure 37: Winter Peak Long Island Margin Calculation – Status Quo System

Long Island Transmission Security Margin											
Winter Peak - Status Quo System, Expected Weather, Normal Transfer Criteria (MW)											
Line	Item	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
A	Zone K Noncoincident Peak Demand Forecast	(3,325)	(3,412)	(3,530)	(3,635)	(3,739)	(3,832)	(3,918)	(4,001)	(4,088)	(4,190)
B	I+J to K (4)	350	350	350	350	350	350	350	350	350	350
C	New England Import (NNC)	0	0	0	0	0	0	0	0	0	0
D	Total K AC Import (B+C)	350	350	350	350	350	350	350	350	350	350
E	Loss of Source Contingency	0	0	0	0	0	0	0	0	0	0
F	Resource Need (A+D+E)	(2,975)	(3,062)	(3,180)	(3,285)	(3,389)	(3,482)	(3,568)	(3,651)	(3,738)	(3,840)
G	K Generation (1)	5,225	5,225	5,225	5,179	5,179	5,179	5,179	5,179	5,179	5,179
H	K Thermal Generation Unavailability - Unavailability of Non-Firm Gas (6)	(374)	(374)	(374)	(328)	(328)	(328)	(328)	(328)	(328)	(328)
I	K Thermal Generation Unavailability - Aging	0	0	0	0	0	(290)	(328)	(363)	(491)	(555)
J	K Thermal Generation Unavailability - EFORd (2)	(572)	(572)	(572)	(572)	(572)	(536)	(531)	(527)	(511)	(504)
K	K Renewable Generation Unavailability - Dispatch Assumptions (3)	(160)	(160)	(160)	(160)	(160)	(160)	(160)	(160)	(160)	(160)
L	SCRs	0	0	0	0	0	0	0	0	0	0
M	Net ICAP External Imports (5)	990	990	990	990	990	990	990	990	990	990
N	Total Resources Available (G+H+I+J+K+L+M)	5,110	5,110	5,110	5,110	5,110	4,855	4,822	4,791	4,679	4,623
O	Noncoincident Peak Transmission Security Margin (F+N)	2,135	2,048	1,930	1,825	1,721	1,373	1,254	1,140	941	783
P	Battery Storage MW	0	0	0	0	0	0	0	0	0	0
Q	Battery Storage MWh Used on Locality Noncoincident Peak Day (7)	0	0	0	0	0	0	0	0	0	0
R	Noncoincident Peak Transmission Security Margin with Batteries (O+Q)	2,135	2,048	1,930	1,825	1,721	1,373	1,254	1,140	941	783
S	Higher Demand Transmission Security Margin with Batteries (8)	2,136	2,044	1,921	1,775	1,593	1,208	1,087	908	714	483

Notes:

1. Reflects the 2026 Gold Book existing winter capacity plus projected additions and deactivations.
2. Reflects derates for thermal resources based on NYCA Zonal Average EFORd.
3. Reflects the derates for renewable generation 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 based on the ratio of solar PV nameplate capacity (2026 Gold Book Table I-9a). For winter solar PV output at peak is 0 MW.
4. Limits for 2027 through 2029 are based on the 2025 LIPA Summer Operating Study. As a conservative assumption summer values are used for LIPA Import limits with one line out. Limits for 2030 through 2036 are based on the 2030 winter peak representations evaluated in the 2026RNA.
5. Interchanges are based on ERAG MMWG values and firm transactions.
6. Unavailability of non-firm gas is modeled per NYSRC Reliability Rule B.1 R1.1 which includes consideration for generation availability including limitations related to weather conditions (e.g. non-firm gas generation unavailability during winter peak). This assessment models all gas only units that do not have a firm gas contract as unavailable and other adjustment to generation assumptions.
7. Consistent with established inclusion rules, battery storage will be used when needed to address a margin deficiency. When margins in line item O are negative, storage will be dispatched beginning with the first hour with a margin deficiency. If battery storage has remaining injection capability at the noncoincident peak hour, battery storage will be dispatched, as available to address the deficiency. If battery storage use at the peak hour is less than the installed MW in line item P, this indicates that by the noncoincident peak hour, storage will not have sufficient energy to discharge at maximum for the peak hour.
8. Higher demand margin calculation not shown in detail in this table.

Figure : Winter Peak Long Island Margin Calculation – Planned System

Long Island Transmission Security Margin											
Winter Peak - Planned System, Expected Weather, Normal Transfer Criteria (MW)											
Line	Item	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
A	Zone K Noncoincident Peak Demand Forecast	(3,325)	(3,412)	(3,530)	(3,635)	(3,739)	(3,832)	(3,918)	(4,001)	(4,088)	(4,190)
B	I+J to K (4)	350	350	350	3,125	3,125	3,125	3,125	3,125	3,125	3,125
C	New England Import (NNC)	0	0	0	0	0	0	0	0	0	0
D	Total K AC Import (B+C)	350	350	350	3,125	3,125	3,125	3,125	3,125	3,125	3,125
E	Loss of Source Contingency	0	0	0	(660)	(660)	(660)	(660)	(660)	(660)	(660)
F	Resource Need (A+D+E)	(2,975)	(3,062)	(3,180)	(1,170)	(1,274)	(1,367)	(1,453)	(1,536)	(1,623)	(1,725)
G	K Generation (1)	6,290	6,290	6,290	6,244	6,244	6,244	6,244	6,244	6,244	6,244
H	K Thermal Generation Unavailability - Unavailability of Non-Firm Gas (6)	(374)	(374)	(374)	(328)	(328)	(328)	(328)	(328)	(328)	(328)
I	K Thermal Generation Unavailability - Aging	0	0	0	0	0	(290)	(328)	(363)	(515)	(581)
J	K Thermal Generation Unavailability - EFORd (2)	(589)	(589)	(589)	(589)	(589)	(553)	(549)	(544)	(526)	(518)
K	K Renewable Generation Unavailability - Dispatch Assumptions (3)	(899)	(899)	(899)	(899)	(899)	(899)	(899)	(899)	(899)	(899)
L	SCRs	0	0	0	0	0	0	0	0	0	0
M	Net ICAP External Imports (5)	990	990	990	990	990	990	990	990	990	990
N	Total Resources Available (G+H+I+J+K+L+M)	5,418	5,418	5,418	5,418	5,418	5,164	5,131	5,100	4,966	4,908
O	Noncoincident Peak Transmission Security Margin (F+N)	2,443	2,356	2,238	4,248	4,144	3,797	3,678	3,564	3,343	3,183
P	Battery Storage MW	0	0	0	0	0	0	0	0	0	0
Q	Battery Storage MWh Used on Locality Noncoincident Peak Day (7)	0	0	0	0	0	0	0	0	0	0
R	Noncoincident Peak Transmission Security Margin with Batteries (O+Q)	2,443	2,356	2,238	4,248	4,144	3,797	3,678	3,564	3,343	3,183
S	Higher Demand Transmission Security Margin with Batteries (8)	2,444	2,352	2,229	4,198	4,016	3,632	3,511	3,332	3,116	2,883

Notes:

1. Reflects the 2026 Gold Book existing winter capacity plus projected additions and deactivations.
2. Reflects derates for thermal resources based on NYCA Zonal Average EFORd.
3. Reflects the derates for renewable generation 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 based on the ratio of solar PV nameplate capacity (2026 Gold Book Table I-9a). For winter solar PV output at peak is 0 MW.
4. Limits for 2027 through 2029 are based on the 2025 LIPA Summer Operating Study. As a conservative assumption summer values are used for LIPA Import limits with one line out. Limits for 2030 through 2036 are based on the 2030 winter peak representations evaluated in the 2026RNA.
5. Interchanges are based on ERAG MMWG values and firm transactions.
6. Unavailability of non-firm gas is modeled per NYSRC Reliability Rule B.1 R1.1 which includes consideration for generation availability including limitations related to weather conditions (e.g. non-firm gas generation unavailability during winter peak). This assessment models all gas only units that do not have a firm gas contract as unavailable and other adjustment to generation assumptions.
7. Consistent with established inclusion rules, battery storage will be used when needed to address a margin deficiency. When margins in line item O are negative, storage will be dispatched beginning with the first hour with a margin deficiency. If battery storage has remaining injection capability at the noncoincident peak hour, battery storage will be dispatched, as available to address the deficiency. If battery storage use at the peak hour is less than the installed MW in line item P, this indicates that by the noncoincident peak hour, storage will not have sufficient energy to discharge at maximum for the peak hour.
8. Higher demand margin calculation not shown in detail in this table.

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 for the as-planned system, considering the higher demand forecast with flexible large loads modeled offline.

- Figure 38: AOI - Statewide System Margin
- Figure 39: AOI - Lower Hudson Valley Transmission Security Margin
- Figure 40: AOI - New York City Transmission Security Margin
- Figure 41: AOI - Long Island Transmission Security Margin

Figure 38: AOI - Statewide System Margin

Statewide System Margin								
Year				2027	2028	2029	2030	2031
Statewide System Margin Summer Peak - Baseline Expected Summer Weather (MW)(1)				1,181	1,405	980	792	209
Unit Name	Summer DMNC (MW)	NYCA Zonal Average De-Rate (MW)	Summer De-Rated Capability (MW)	Transmission Security Margin Considering Impact of Generator Outage (Retire, Mothball, IIFO)				
Jamestown 5, 6, 7	62.6	(2.07)	60.5	1,121	1,345	919	731	148
Jamestown 5	11.8	(0.39)	11.4	1,170	1,394	969	780	197
Jamestown 6	10.3	(0.34)	10.0	1,171	1,395	970	782	199
Jamestown 7	40.5	(1.34)	39.2	1,142	1,366	941	753	170
Indeck-Yerkes	46.5	(1.54)	45.0	1,136	1,360	935	747	164
Indeck-Olean	79.2	(2.62)	76.6	1,105	1,329	903	715	132
American Ref Fuel 1 & 2	27.6	(0.91)	26.7	1,155	1,379	953	765	182
American Ref-Fuel 1	13.8	(0.46)	13.3	1,168	1,392	967	778	196
American Ref-Fuel 2	13.8	(0.46)	13.3	1,168	1,392	967	778	196
Lockport CC1, CC2, & CC3	206.1	(6.82)	199.3	982	1,206	781	592	10
Lockport CC1	68.7	(2.27)	66.4	1,115	1,339	914	725	142
Lockport CC2	68.7	(2.27)	66.4	1,115	1,339	914	725	142
Lockport CC3	68.7	(2.27)	66.4	1,115	1,339	914	725	142
Allegany	62.2	(1.75)	60.4	1,121	1,345	920	731	148
R. E. Ginna	578.8	(16.33)	562.5	619	843	418	229	(354)
Batavia	48.5	(1.37)	47.1	1,134	1,358	933	745	162
Nine Mile Point 1	605.3	(34.92)	570.4	611	835	410	221	(361)
Nine Mile Point 2 (2)	1,276.9	(73.67)	1,203.2	(22)	202	(223)	(412)	(994)
James A. FitzPatrick	840.7	(48.51)	792.2	389	613	188	(0)	(583)
Oswego 5	800.6	(46.19)	754.4	427	651	226	37	(546)
Oswego 6	812.9	(46.90)	766.0	415	639	214	26	(557)
Indeck-Silver Springs	52.3	(3.02)	49.3	1,132	1,356	931	742	160
Indeck-Oswego	51.6	(2.98)	48.6	1,133	1,357	931	743	160
Syracuse	86.2	(4.97)	81.2	1,100	1,324	899	710	128
Carr St.-E. Syr	83.0	(4.79)	78.2	1,103	1,327	902	714	131
Independence GS1, GS2, GS3, & GS4	1017.2	(58.69)	958.5	223	447	21	(167)	(750)
Independence GS1	254.3	(14.67)	239.6	942	1,166	740	552	(31)
Independence GS2	254.3	(14.67)	239.6	942	1,166	740	552	(31)
Independence GS3	254.3	(14.67)	239.6	942	1,166	740	552	(31)
Independence GS4	254.3	(14.67)	239.6	942	1,166	740	552	(31)
Massena	80.9	(8.48)	72.4	1,109	1,333	908	719	136
Saranac Energy CC1 & CC2	237.7	(24.93)	212.8	969	1,193	767	579	(4)
Saranac Energy CC1	123.4	(12.94)	110.5	1,071	1,295	870	681	98
Saranac Energy CC2	114.3	(11.99)	102.3	1,079	1,303	878	689	107
Sterling	48.4	(7.67)	40.7	1,141	1,365	939	751	168
Carthage Energy	52.8	(8.36)	44.4	1,137	1,361	936	747	164
Beaver Falls	79.8	(12.64)	67.2	1,114	1,338	913	725	142
Athens 1, 2, & 3	983.3	(33.69)	949.6	232	456	30	(158)	(741)
Athens 1	326.6	(11.19)	315.4	866	1,090	665	476	(107)
Athens 2	327.4	(11.22)	316.2	865	1,089	664	476	(107)
Athens 3	329.3	(11.28)	318.0	863	1,087	662	474	(109)
Rensselaer	77.0	(2.64)	74.4	1,107	1,331	906	717	135
Selkirk I & II	348.3	(11.93)	336.4	845	1,069	644	455	(127)
Selkirk-I	75.2	(2.58)	72.6	1,109	1,333	907	719	136
Selkirk-II	273.1	(9.36)	263.7	918	1,142	716	528	(55)
Indeck-Corinth	126.4	(4.33)	122.1	1,059	1,283	858	670	87
Castleton Energy Center	66.8	(2.29)	64.5	1,117	1,341	915	727	144

Statewide System Margin								
Year				2027	2028	2029	2030	2031
Statewide System Margin Summer Peak - Baseline Expected Summer Weather (MW)(1)				1,181	1,405	980	792	209
Unit Name	Summer DMNC (MW)	NYCA Zonal Average De-Rate (MW)	Summer De-Rated Capability (MW)	Transmission Security Margin Considering Impact of Generator Outage (Retire, Mothball, IIFO)				
Bethlehem GS1, GS2, & GS3	812.7	(27.85)	784.9	397	620	195	7	(576)
Bethlehem GS1	270.9	(9.28)	261.6	920	1,144	718	530	(53)
Bethlehem GS2	270.9	(9.28)	261.6	920	1,144	718	530	(53)
Bethlehem GS3	270.9	(9.28)	261.6	920	1,144	718	530	(53)
Empire CC1 & CC2	584.8	(20.04)	564.8	617	841	415	227	(356)
Empire CC1	292.4	(10.02)	282.4	899	1,123	698	509	(73)
Empire CC2	292.4	(10.02)	282.4	899	1,123	698	509	(73)
Bowline 1 & 2	1083.3	(176.82)	906.5	275	499	73	(115)	(698)
Bowline 1	541.7	(88.42)	453.3	728	952	527	338	(244)
Bowline 2	541.6	(88.40)	453.2	728	952	527	339	(244)
Roseton 1 & 2	1208.8	(197.30)	1011.5	170	394	(32)	(220)	(803)
Roseton 1	605.5	(98.83)	506.7	675	899	473	285	(298)
Roseton 2	603.3	(98.47)	504.8	677	900	475	287	(296)
Hillburn GT	36.3	(5.92)	30.4	1,151	1,375	950	761	179
Shoemaker GT	32.1	(5.24)	26.9	1,155	1,378	953	765	182
DCRRA	6.3	(1.03)	5.3	1,176	1,400	975	786	204
CPV Valley CC1 & CC2	654.2	(106.78)	547.4	634	858	433	244	(339)
CPV Valley CC1	323.3	(52.77)	270.5	911	1,135	709	521	(62)
CPV Valley CC2	330.9	(54.01)	276.9	905	1,128	703	515	(68)
Cricket Valley CC1, CC2, & CC3	1046.2	(170.76)	875.4	306	530	105	(84)	(667)
Cricket Valley CC1	347.6	(56.74)	290.9	891	1,114	689	501	(82)
Cricket Valley CC2	347.4	(56.70)	290.7	891	1,115	689	501	(82)
Cricket Valley CC3	351.2	(57.32)	293.9	888	1,111	686	498	(85)
Wheelabrator Westchester	53.3	(6.62)	46.7	1,135	1,359	933	745	162
Arthur Kill ST 2 & 3	876.6	(70.44)	806.2	375	599	174	(14)	(597)
Arthur Kill ST 2	358.2	(28.78)	329.4	852	1,076	651	462	(121)
Arthur Kill ST 3	518.4	(41.65)	476.7	705	929	503	315	(268)
Brooklyn Navy Yard	250.8	(20.15)	230.6	951	1,175	749	561	(22)
Astoria 2, 3, & 5	899.5	(72.28)	827.2	354	578	153	(36)	(618)
Astoria 2	159.5	(12.82)	146.7	1,035	1,259	833	645	62
Astoria 3	369.9	(29.72)	340.2	841	1,065	640	452	(131)
Astoria 5	370.1	(29.74)	340.4	841	1,065	640	451	(131)
Ravenswood ST 01, 02, & 03	1723.3	(138.47)	1584.8	(403)	(180)	(605)	(793)	(1,376)
Ravenswood ST 01	360.3	(28.95)	331.3	850	1,074	649	460	(122)
Ravenswood ST 02	375.1	(30.14)	345.0	836	1,060	635	447	(136)
Ravenswood ST 03	987.9	(79.38)	908.5	273	497	71	(117)	(700)
Ravenswood CC 04	223.9	(17.99)	205.9	975	1,199	774	586	3
East River 1, 2, 6, & 7	615.5	(49.46)	566.0	615	839	414	226	(357)
East River 1	152.1	(12.22)	139.9	1,042	1,265	840	652	69
East River 2	153.9	(12.37)	141.5	1,040	1,264	838	650	67
East River 6	132.7	(10.66)	122.0	1,059	1,283	858	670	87
East River 7	176.8	(14.21)	162.6	1,019	1,243	817	629	46
Linden Cogen	715.0	(57.45)	657.5	524	748	322	134	(449)
Gowanus 2-1 through 3-8 (3)	263.5	(21.17)	242.3	939	1,163	-	-	-
Gowanus 2-1 (3)	16.2	(1.30)	14.9	1,167	1,390	-	-	-
Gowanus 2-2 (3)	17.2	(1.38)	15.8	1,166	1,389	-	-	-
Gowanus 2-3 (3)	18.9	(1.52)	17.4	1,164	1,388	-	-	-

Statewide System Margin								
Year				2027	2028	2029	2030	2031
Statewide System Margin Summer Peak - Baseline Expected Summer Weather (MW)(1)				1,181	1,405	980	792	209
Unit Name	Summer DMNC (MW)	NYCA Zonal Average De-Rate (MW)	Summer De-Rated Capability (MW)	Transmission Security Margin Considering Impact of Generator Outage (Retire, Mothball, IIFO)				
Gowanus 2-4 (3)	16.8	(1.35)	15.5	1,166	1,390	-	-	-
Gowanus 2-5 (3)	17.4	(1.40)	16.0	1,165	1,389	-	-	-
Gowanus 2-6 (3)	18.8	(1.51)	17.3	1,164	1,388	-	-	-
Gowanus 2-7 (3)	18.4	(1.48)	16.9	1,164	1,388	-	-	-
Gowanus 2-8 (3)	17.5	(1.41)	16.1	1,165	1,389	-	-	-
Gowanus 3-1 (3)	17.0	(1.37)	15.6	1,166	1,390	-	-	-
Gowanus 3-2 (3)	17.2	(1.38)	15.8	1,166	1,389	-	-	-
Gowanus 3-3 (3)	18.0	(1.45)	16.6	1,165	1,389	-	-	-
Gowanus 3-4 (3)	16.4	(1.32)	15.1	1,166	1,390	-	-	-
Gowanus 3-5 (3)	18.0	(1.45)	16.6	1,165	1,389	-	-	-
Gowanus 3-7 (3)	18.1	(1.45)	16.6	1,165	1,389	-	-	-
Gowanus 3-8 (3)	17.6	(1.41)	16.2	1,165	1,389	-	-	-
Gowanus 5 & 6 (4)	79.9	(6.42)	73.5	1,108	1,332	906	718	-
Gowanus 5 (4)	40.0	(3.21)	36.8	1,145	1,369	943	755	-
Gowanus 6 (4)	39.9	(3.21)	36.7	1,145	1,369	943	755	-
Kent (4)	40.0	(3.21)	36.8	1,145	1,369	943	755	-
Pouch (4)	39.2	(3.15)	36.1	1,145	1,369	944	756	-
Hellgate 1 & 2 (4)	79.5	(6.39)	73.1	1,108	1,332	907	719	-
Hellgate 1 (4)	39.9	(3.21)	36.7	1,145	1,369	943	755	-
Hellgate 2 (4)	39.6	(3.18)	36.4	1,145	1,369	944	755	-
Harlem River 1 & 2 (4)	79.5	(6.39)	73.1	1,108	1,332	907	719	-
Harlem River 1 (4)	39.9	(3.21)	36.7	1,145	1,369	943	755	-
Harlem River 2 (4)	39.6	(3.18)	36.4	1,145	1,369	944	755	-
Vernon Blvd 2 & 3 (4)	79.9	(6.42)	73.5	1,108	1,332	906	718	-
Vernon Blvd 2 (4)	40.0	(3.21)	36.8	1,145	1,369	943	755	-
Vernon Blvd 3 (4)	39.9	(3.21)	36.7	1,145	1,369	943	755	-
Narrows 1-1 through 2-8 (3)	242.3	(19.47)	222.8	959	1,182	-	-	-
Narrows 1-1 (3)	17.6	(1.41)	16.2	1,165	1,389	-	-	-
Narrows 1-2 (3)	16.4	(1.32)	15.1	1,166	1,390	-	-	-
Narrows 1-3 (3)	16.7	(1.34)	15.4	1,166	1,390	-	-	-
Narrows 1-4 (3)	17.1	(1.37)	15.7	1,166	1,390	-	-	-
Narrows 1-5 (3)	18.0	(1.45)	16.6	1,165	1,389	-	-	-
Narrows 1-6 (3)	15.0	(1.21)	13.8	1,168	1,391	-	-	-
Narrows 1-7 (3)	17.5	(1.41)	16.1	1,165	1,389	-	-	-
Narrows 1-8 (3)	15.7	(1.26)	14.4	1,167	1,391	-	-	-
Narrows 2-2 (3)	16.3	(1.31)	15.0	1,166	1,390	-	-	-
Narrows 2-3 (3)	16.4	(1.32)	15.1	1,166	1,390	-	-	-
Narrows 2-4 (3)	18.1	(1.45)	16.6	1,165	1,389	-	-	-
Narrows 2-5 (3)	20.2	(1.62)	18.6	1,163	1,387	-	-	-
Narrows 2-6 (3)	20.0	(1.61)	18.4	1,163	1,387	-	-	-
Narrows 2-8 (3)	17.3	(1.39)	15.9	1,165	1,389	-	-	-
Astoria CC 1 & 2	474	(38.09)	435.9	745	969	544	356	(227)
Astoria CC 1	237.0	(19.04)	218.0	963	1,187	762	574	(9)
Astoria CC 2	237.0	(19.04)	218.0	963	1,187	762	574	(9)
Astoria East Energy CC1 & CC2	589.2	(47.34)	541.9	640	863	438	250	(333)
Astoria East Energy - CC1	294.6	(23.67)	270.9	910	1,134	709	521	(62)
Astoria East Energy - CC2	294.6	(23.67)	270.9	910	1,134	709	521	(62)

Statewide System Margin								
Year				2027	2028	2029	2030	2031
Statewide System Margin Summer Peak - Baseline Expected Summer Weather (MW)(1)				1,181	1,405	980	792	209
Unit Name	Summer DMNC (MW)	NYCA Zonal 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	(45.80)	524.2	657	881	456	268	(315)
Astoria Energy 2 - CC3	285.0	(22.90)	262.1	919	1,143	718	530	(53)
Astoria Energy 2 - CC4	285.0	(22.90)	262.1	919	1,143	718	530	(53)
Bayonne EC CTG1 through CTG10	592.7	(47.62)	545.1	636	860	435	247	(336)
Bayonne EC CTG1	59.5	(4.78)	54.7	1,127	1,351	925	737	154
Bayonne EC CTG2	54.6	(4.39)	50.2	1,131	1,355	930	742	159
Bayonne EC CTG3	58.8	(4.72)	54.1	1,127	1,351	926	738	155
Bayonne EC CTG4	61.1	(4.91)	56.2	1,125	1,349	924	736	153
Bayonne EC CTG5	59.9	(4.81)	55.1	1,126	1,350	925	737	154
Bayonne EC CTG6	60.5	(4.86)	55.6	1,126	1,350	924	736	153
Bayonne EC CTG7	57.0	(4.58)	52.4	1,129	1,353	928	739	156
Bayonne EC CTG8	60.5	(4.86)	55.6	1,126	1,350	924	736	153
Bayonne EC CTG9	60.4	(4.85)	55.5	1,126	1,350	924	736	153
Bayonne EC CTG10	60.4	(4.85)	55.5	1,126	1,350	924	736	153
Greenport IC 4, 5, & 6	5.6	(0.69)	4.9	1,176	1,400	975	787	204
Greenport IC 4	1.0	(0.12)	0.9	1,181	1,404	979	791	208
Greenport IC 5	1.5	(0.18)	1.3	1,180	1,404	979	790	208
Greenport IC 6	3.1	(0.38)	2.7	1,179	1,403	977	789	206
Freeport 1-2, 1-3, & 2-3	21.5	(2.63)	18.9	1,163	1,386	961	773	190
Freeport 1-2	2.5	(0.31)	2.2	1,179	1,403	978	790	207
Freeport 1-3	3.0	(0.37)	2.6	1,179	1,403	977	789	206
Freeport 2-3	16.0	(1.96)	14.0	1,167	1,391	966	778	195
Charles P Keller 09 through 14	13.4	(1.64)	11.8	1,170	1,394	968	780	197
Charles P Keller 09	1.6	(0.20)	1.4	1,180	1,404	979	790	207
Charles P Keller 10	1.6	(0.20)	1.4	1,180	1,404	979	790	207
Charles P Keller 11	2.4	(0.29)	2.1	1,179	1,403	978	790	207
Charles P Keller 12	2.5	(0.31)	2.2	1,179	1,403	978	790	207
Charles P Keller 13	2.5	(0.31)	2.2	1,179	1,403	978	790	207
Charles P Keller 14	2.8	(0.34)	2.5	1,179	1,403	978	789	206
Wading River 1, 2, & 3	228.9	(28.05)	200.9	981	1,204	779	591	8
Wading River 1	77.4	(9.48)	67.9	1,113	1,337	912	724	141
Wading River 2	76.7	(9.40)	67.3	1,114	1,338	913	724	142
Wading River 3	74.8	(9.16)	65.6	1,116	1,340	914	726	143
Barrett ST 01 & 02	325.3	(39.86)	285.4	896	1,120	695	506	(77)
Barrett ST 01	144.3	(17.68)	126.6	1,055	1,279	853	665	82
Barrett ST 02	181.0	(22.18)	158.8	1,023	1,246	821	633	50
Barrett GT 01 through 12	259.4	(31.78)	227.6	954	1,178	752	564	(19)
Barrett GT 01	14.2	(1.74)	12.5	1,169	1,393	968	779	196
Barrett GT 02	14.3	(1.75)	12.5	1,169	1,393	967	779	196
Barrett 03	13.8	(1.69)	12.1	1,169	1,393	968	780	197
Barrett 04	15.1	(1.85)	13.2	1,168	1,392	967	778	196
Barrett 05	12.7	(1.56)	11.1	1,170	1,394	969	781	198
Barrett 06	14.0	(1.72)	12.3	1,169	1,393	968	779	197
Barrett 08	13.3	(1.63)	11.7	1,170	1,394	968	780	197
Barrett 09	40.4	(4.95)	35.5	1,146	1,370	945	756	173
Barrett 10	41.3	(5.06)	36.2	1,145	1,369	944	755	173
Barrett 11	40.0	(4.90)	35.1	1,146	1,370	945	757	174

Statewide System Margin								
Year				2027	2028	2029	2030	2031
Statewide System Margin Summer Peak - Baseline Expected Summer Weather (MW)(1)				1,181	1,405	980	792	209
Unit Name	Summer DMNC (MW)	NYCA Zonal Average De-Rate (MW)	Summer De-Rated Capability (MW)	Transmission Security Margin Considering Impact of Generator Outage (Retire, Mothball, IIFO)				
Barrett 12	40.3	(4.94)	35.4	1,146	1,370	945	756	174
Northport 1, 2, 3, and 4	1452	(177.90)	1274.1	(93)	131	(294)	(482)	(1,065)
Northport 1	363.0	(44.48)	318.5	863	1,087	661	473	(110)
Northport 2	363.0	(44.48)	318.5	863	1,087	661	473	(110)
Northport 3	363.0	(44.48)	318.5	863	1,087	661	473	(110)
Northport 4	363.0	(44.48)	318.5	863	1,087	661	473	(110)
Port Jefferson GT 02 & 03	78.1	(9.57)	68.5	1,113	1,337	911	723	140
Port Jefferson GT 02	38.8	(4.75)	34.0	1,147	1,371	946	758	175
Port Jefferson GT 03	39.3	(4.82)	34.5	1,147	1,371	945	757	174
Port Jefferson 3 & 4	359.8	(44.08)	315.7	866	1,090	664	476	(107)
Port Jefferson 3	178.8	(21.91)	156.9	1,025	1,248	823	635	52
Port Jefferson 4	181.0	(22.18)	158.8	1,023	1,246	821	633	50
Hempstead (RR)	74.5	(9.13)	65.4	1,116	1,340	915	726	144
Glenwood GT 02, 03, 04, & 05	179.9	(22.04)	157.9	1,024	1,247	822	634	51
Glenwood GT 02	48.3	(5.92)	42.4	1,139	1,363	938	749	167
Glenwood GT 03	53.0	(6.49)	46.5	1,135	1,359	933	745	162
Glenwood GT 04	38.4	(4.70)	33.7	1,148	1,372	946	758	175
Glenwood GT 05	40.2	(4.93)	35.3	1,146	1,370	945	756	174
Holtsville 01 through 10	510.1	(62.50)	447.6	734	958	532	344	(239)
Holtsville 01	53.0	(6.49)	46.5	1,135	1,359	933	745	162
Holtsville 02	52.0	(6.37)	45.6	1,136	1,360	934	746	163
Holtsville 03	46.9	(5.75)	41.2	1,140	1,364	939	751	168
Holtsville 04	50.9	(6.24)	44.7	1,137	1,361	935	747	164
Holtsville 05	49.4	(6.05)	43.3	1,138	1,362	937	748	166
Holtsville 06	52.7	(6.46)	46.2	1,135	1,359	934	745	163
Holtsville 07	50.0	(6.13)	43.9	1,138	1,361	936	748	165
Holtsville 08	49.6	(6.08)	43.5	1,138	1,362	936	748	165
Holtsville 09	52.3	(6.41)	45.9	1,136	1,359	934	746	163
Holtsville 10	53.3	(6.53)	46.8	1,135	1,359	933	745	162
Shoreham 1	46.0	(5.64)	40.4	1,141	1,365	940	751	169
Shoreham 2	16.7	(2.05)	14.7	1,167	1,391	965	777	194
Shoreham GT3 & GT4	82.7	(10.13)	72.6	1,109	1,333	907	719	136
Shoreham GT3	41.4	(5.07)	36.3	1,145	1,369	944	755	173
Shoreham GT4	41.3	(5.06)	36.2	1,145	1,369	944	755	173
East Hampton GT 01, 2, 3, & 4	23.5	(2.88)	20.6	1,161	1,385	959	771	188
East Hampton GT 01	18.1	(2.22)	15.9	1,166	1,389	964	776	193
East Hampton 2	1.8	(0.22)	1.6	1,180	1,404	978	790	207
East Hampton 3	1.8	(0.22)	1.6	1,180	1,404	978	790	207
East Hampton 4	1.8	(0.22)	1.6	1,180	1,404	978	790	207
Southold 1	9.8	(1.20)	8.6	1,173	1,397	971	783	200
S Hampton 1	8.1	(0.99)	7.1	1,174	1,398	973	785	202
Freeport CT 1 & 2	88.7	(10.87)	77.8	1,104	1,327	902	714	131
Freeport CT 1	45.7	(5.60)	40.1	1,141	1,365	940	752	169
Freeport CT 2	43.0	(5.27)	37.7	1,144	1,368	942	754	171
Flynn	139.5	(17.09)	122.4	1,059	1,283	858	669	86
Greenport GT1	54.5	(6.68)	47.8	1,134	1,357	932	744	161
Far Rockaway GT1 & GT2	94.9	(11.63)	83.3	1,098	1,322	897	708	126

Statewide System Margin								
Year				2027	2028	2029	2030	2031
Statewide System Margin Summer Peak - Baseline Expected Summer Weather (MW)(1)				1,181	1,405	980	792	209
Unit Name	Summer DMNC (MW)	NYCA Zonal Average De-Rate (MW)	Summer De-Rated Capability (MW)	Transmission Security Margin Considering Impact of Generator Outage (Retire, Mothball, IIFO)				
Far Rockaway GT1	48.9	(5.99)	42.9	1,138	1,362	937	749	166
Far Rockaway GT2	46.0	(5.64)	40.4	1,141	1,365	940	751	169
Bethpage	46.0	(5.64)	40.4	1,141	1,365	940	751	169
Bethpage 3	75.0	(9.19)	65.8	1,116	1,339	914	726	143
Bethpage GT4	43.8	(5.37)	38.4	1,143	1,367	942	753	170
Brentwood (4)	45.0	(5.51)	39.5	1,142	1,366	940	752	-
Pilgrim GT1 & GT2	84.9	(10.40)	74.5	1,107	1,331	905	717	134
Pilgrim GT1	42.0	(5.15)	36.9	1,145	1,368	943	755	172
Pilgrim GT2	42.9	(5.26)	37.6	1,144	1,368	942	754	171
Caithness_CC_1	321.8	(39.43)	282.4	899	1,123	698	509	(73)
Islip (RR)	7.5	(0.92)	6.6	1,175	1,399	973	785	202
Babylon (RR)	15.8	(1.94)	13.9	1,168	1,391	966	778	195
Huntington (RR)	24.8	(3.04)	21.8	1,160	1,384	958	770	187

Notes

1. Utilizes the as-planned baseline margin result.
2. Utilizes the next largest generation contingency outage which is the loss of Cricket Valley CC1, CC2, & CC3.
3. Unit is modeled out of service beginning in 2029 in the baseline margin calculation.
4. Unit is modeled out of service beginning in 2031 in the baseline margin calculation.

Figure 39: AOI - Lower Hudson Valley Transmission Security Margin

Lower Hudson Valley System Margin								
Year				2027	2028	2029	2030	2031
Lower Hudson Valley Transmission Security Margin Summer Peak - Baseline Expected Summer Weather, Normal Transfer Criteria (MW)(1)				1,645	1,717	1,195	1,227	717
Unit Name	Summer DMNC (MW)	NYCA Zonal Average De-Rate (MW)	Summer De-Rated Capability (MW)	Transmission Security Margin Considering Impact of Generator Outage (Retire, Mothball, IIFO)				
Bowline 1 & 2	1,083.3	(176.8)	906.5	739	811	289	321	(189)
Bowline 1	541.7	(88.4)	453.3	1,192	1,264	742	774	264
Bowline 2	541.6	(88.4)	453.2	1,192	1,264	742	774	264
Roseton 1 & 2	1,208.8	(197.3)	1,011.5	634	706	184	216	(294)
Roseton 1	605.5	(98.8)	506.7	1,139	1,211	688	721	210
Roseton 2	603.3	(98.5)	504.8	1,141	1,212	690	722	212
Hillburn GT	36.3	(5.9)	30.4	1,615	1,687	1,165	1,197	687
Shoemaker GT	32.1	(5.2)	26.9	1,619	1,690	1,168	1,200	690
DCRRA	6.3	(1.0)	5.3	1,640	1,712	1,190	1,222	712
CPV Valley CC1 & CC2	654.2	(106.8)	547.4	1,098	1,170	648	680	170
CPV Valley CC1	323.3	(52.8)	270.5	1,375	1,447	925	957	446
CPV Valley CC2	330.9	(54.0)	276.9	1,369	1,440	918	950	440
Cricket Valley CC1, CC2, & CC3	1,046.2	(170.8)	875.4	770	842	320	352	(158)
Cricket Valley CC1	347.6	(56.7)	290.9	1,355	1,426	904	936	426
Cricket Valley CC2	347.4	(56.7)	290.7	1,355	1,427	904	937	426
Cricket Valley CC3	351.2	(57.3)	293.9	1,352	1,423	901	933	423
Wheelabrator Westchester	53.3	(6.6)	46.7	1,599	1,671	1,148	1,181	670
Arthur Kill ST 2 & 3	876.6	(70.4)	806.2	839	911	389	421	(89)
Arthur Kill ST 2	358.2	(28.8)	329.4	1,316	1,388	866	898	388
Arthur Kill ST 3	518.4	(41.7)	476.7	1,169	1,240	718	750	240
Brooklyn Navy Yard	250.8	(20.2)	230.6	1,415	1,487	964	997	486
Astoria 2, 3, & 5	899.5	(72.3)	827.2	818	890	368	400	(110)
Astoria 2	159.5	(12.8)	146.7	1,499	1,571	1,048	1,081	570
Astoria 3	369.9	(29.7)	340.2	1,305	1,377	855	887	377
Astoria 5	370.1	(29.7)	340.4	1,305	1,377	855	887	377
Ravenswood ST 01, 02, & 03	1,723.3	(138.5)	1,584.8	61	132	(390)	(358)	(868)
Ravenswood ST 01	360.3	(29.0)	331.3	1,314	1,386	864	896	386
Ravenswood ST 02	375.1	(30.1)	345.0	1,301	1,372	850	882	372
Ravenswood ST 03	987.9	(79.4)	908.5	737	809	287	319	(191)
Ravenswood CC 04	223.9	(18.0)	205.9	1,440	1,511	989	1,021	511
East River 1, 2, 6, & 7	615.5	(49.5)	566.0	1,079	1,151	629	661	151
East River 1	152.1	(12.2)	139.9	1,506	1,577	1,055	1,087	577
East River 2	153.9	(12.4)	141.5	1,504	1,576	1,054	1,086	575
East River 6	132.7	(10.7)	122.0	1,523	1,595	1,073	1,105	595
East River 7	176.8	(14.2)	162.6	1,483	1,555	1,032	1,065	554
Linden Cogen	715.0	(57.5)	657.5	988	1,060	538	570	59
Gowanus 2-1 through 3-8 (2)	263.5	(21.2)	242.3	1,403	1,475	-	-	-
Gowanus 2-1 (2)	16.2	(1.3)	14.9	1,631	1,702	-	-	-
Gowanus 2-2 (2)	17.2	(1.4)	15.8	1,630	1,701	-	-	-
Gowanus 2-3 (2)	18.9	(1.5)	17.4	1,628	1,700	-	-	-
Gowanus 2-4 (2)	16.8	(1.3)	15.5	1,630	1,702	-	-	-
Gowanus 2-5 (2)	17.4	(1.4)	16.0	1,629	1,701	-	-	-
Gowanus 2-6 (2)	18.8	(1.5)	17.3	1,628	1,700	-	-	-
Gowanus 2-7 (2)	18.4	(1.5)	16.9	1,629	1,700	-	-	-

Lower Hudson Valley System Margin									
				Year	2027	2028	2029	2030	2031
Lower Hudson Valley Transmission Security Margin Summer Peak - Baseline Expected Summer Weather, Normal Transfer Criteria (MW)(1)					1,645	1,717	1,195	1,227	717
Unit Name	Summer DMNC (MW)	NYCA Zonal Average De-Rate (MW)	Summer De-Rated Capability (MW)	Transmission Security Margin Considering Impact of Generator Outage (Retire, Mothball, IIFO)					
Gowanus 2-8 (2)	17.5	(1.4)	16.1	1,629	1,701	-	-	-	-
Gowanus 3-1 (2)	17.0	(1.4)	15.6	1,630	1,702	-	-	-	-
Gowanus 3-2 (2)	17.2	(1.4)	15.8	1,630	1,701	-	-	-	-
Gowanus 3-3 (2)	18.0	(1.4)	16.6	1,629	1,701	-	-	-	-
Gowanus 3-4 (2)	16.4	(1.3)	15.1	1,630	1,702	-	-	-	-
Gowanus 3-5 (2)	18.0	(1.4)	16.6	1,629	1,701	-	-	-	-
Gowanus 3-7 (2)	18.1	(1.5)	16.6	1,629	1,701	-	-	-	-
Gowanus 3-8 (2)	17.6	(1.4)	16.2	1,629	1,701	-	-	-	-
Gowanus 5 & 6 (3)	79.9	(6.4)	73.5	1,572	1,644	1,122	1,154	-	-
Gowanus 5 (3)	40.0	(3.2)	36.8	1,609	1,680	1,158	1,190	-	-
Gowanus 6 (3)	39.9	(3.2)	36.7	1,609	1,681	1,158	1,191	-	-
Kent (3)	40.0	(3.2)	36.8	1,609	1,680	1,158	1,190	-	-
Pouch (3)	39.2	(3.1)	36.1	1,609	1,681	1,159	1,191	-	-
Hellgate 1 & 2 (3)	79.5	(6.4)	73.1	1,572	1,644	1,122	1,154	-	-
Hellgate 1 (3)	39.9	(3.2)	36.7	1,609	1,681	1,158	1,191	-	-
Hellgate 2 (3)	39.6	(3.2)	36.4	1,609	1,681	1,159	1,191	-	-
Harlem River 1 & 2 (3)	79.5	(6.4)	73.1	1,572	1,644	1,122	1,154	-	-
Harlem River 1 (3)	39.9	(3.2)	36.7	1,609	1,681	1,158	1,191	-	-
Harlem River 2 (3)	39.6	(3.2)	36.4	1,609	1,681	1,159	1,191	-	-
Vernon Blvd 2 & 3 (3)	79.9	(6.4)	73.5	1,572	1,644	1,122	1,154	-	-
Vernon Blvd 2 (3)	40.0	(3.2)	36.8	1,609	1,680	1,158	1,190	-	-
Vernon Blvd 3 (3)	39.9	(3.2)	36.7	1,609	1,681	1,158	1,191	-	-
Narrows 1-1 through 2-8 (2)	242.3	(19.5)	222.8	1,423	1,494	-	-	-	-
Narrows 1-1 (2)	17.6	(1.4)	16.2	1,629	1,701	-	-	-	-
Narrows 1-2 (2)	16.4	(1.3)	15.1	1,630	1,702	-	-	-	-
Narrows 1-3 (2)	16.7	(1.3)	15.4	1,630	1,702	-	-	-	-
Narrows 1-4 (2)	17.1	(1.4)	15.7	1,630	1,701	-	-	-	-
Narrows 1-5 (2)	18.0	(1.4)	16.6	1,629	1,701	-	-	-	-
Narrows 1-6 (2)	15.0	(1.2)	13.8	1,632	1,703	-	-	-	-
Narrows 1-7 (2)	17.5	(1.4)	16.1	1,629	1,701	-	-	-	-
Narrows 1-8 (2)	15.7	(1.3)	14.4	1,631	1,703	-	-	-	-
Narrows 2-2 (2)	16.3	(1.3)	15.0	1,630	1,702	-	-	-	-
Narrows 2-3 (2)	16.4	(1.3)	15.1	1,630	1,702	-	-	-	-
Narrows 2-4 (2)	18.1	(1.5)	16.6	1,629	1,701	-	-	-	-
Narrows 2-5 (2)	20.2	(1.6)	18.6	1,627	1,699	-	-	-	-
Narrows 2-6 (2)	20.0	(1.6)	18.4	1,627	1,699	-	-	-	-
Narrows 2-8 (2)	17.3	(1.4)	15.9	1,630	1,701	-	-	-	-
Astoria CC 1 & 2	474.0	(38.1)	435.9	1,210	1,281	759	791	281	-
Astoria CC 1	237.0	(19.0)	218.0	1,428	1,499	977	1,009	499	-
Astoria CC 2	237.0	(19.0)	218.0	1,428	1,499	977	1,009	499	-
Astoria East Energy CC1 & CC2	589.2	(47.3)	541.9	1,104	1,175	653	685	175	-
Astoria East Energy - CC1	294.6	(23.7)	270.9	1,375	1,446	924	956	446	-
Astoria East Energy - CC2	294.6	(23.7)	270.9	1,375	1,446	924	956	446	-
Astoria Energy 2 CC3 & CC4	570.0	(45.8)	524.2	1,121	1,193	671	703	193	-

Lower Hudson Valley System Margin								
Year				2027	2028	2029	2030	2031
Lower Hudson Valley Transmission Security Margin Summer Peak - Baseline Expected Summer Weather, Normal Transfer Criteria (MW)(1)				1,645	1,717	1,195	1,227	717
Unit Name	Summer DMNC (MW)	NYCA Zonal Average De-Rate (MW)	Summer De-Rated Capability (MW)	Transmission Security Margin Considering Impact of Generator Outage (Retire, Mothball, IIFO)				
Astoria Energy 2 - CC3	285.0	(22.9)	262.1	1,383	1,455	933	965	455
Astoria Energy 2 - CC4	285.0	(22.9)	262.1	1,383	1,455	933	965	455
Bayonne EC CTG1 through CTG10	592.7	(47.6)	545.1	1,100	1,172	650	682	172
Bayonne EC CTG1	59.5	(4.8)	54.7	1,591	1,662	1,140	1,173	662
Bayonne EC CTG2	54.6	(4.4)	50.2	1,595	1,667	1,145	1,177	667
Bayonne EC CTG3	58.8	(4.7)	54.1	1,591	1,663	1,141	1,173	663
Bayonne EC CTG4	61.1	(4.9)	56.2	1,589	1,661	1,139	1,171	661
Bayonne EC CTG5	59.9	(4.8)	55.1	1,590	1,662	1,140	1,172	662
Bayonne EC CTG6	60.5	(4.9)	55.6	1,590	1,662	1,139	1,172	661
Bayonne EC CTG7	57.0	(4.6)	52.4	1,593	1,665	1,143	1,175	665
Bayonne EC CTG8	60.5	(4.9)	55.6	1,590	1,662	1,139	1,172	661
Bayonne EC CTG9	60.4	(4.9)	55.5	1,590	1,662	1,140	1,172	661
Bayonne EC CTG10	60.4	(4.9)	55.5	1,590	1,662	1,140	1,172	661

Notes

1. Utilizes the most severe margin result from as-planned noncoincident or as-planned higher demand.
2. Unit is modeled out of service beginning in 2029 in the baseline margin calculation.
3. Unit is modeled out of service beginning in 2031 in the baseline margin calculation.

Figure 40: AOI - New York City Transmission Security Margin

New York City								
Year				2027	2028	2029	2030	2031
New York City Transmission Security Margin Summer Peak - Baseline Expected Summer Weather, Normal Transfer Criteria (MW)(1)				618	680	195	265	(131)
Unit Name	Summer DMNC (MW)	NYCA Zonal 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	876.6	(70.4)	806.2	(188)	(126)	(612)	(542)	(938)
Arthur Kill ST 2	358.2	(28.8)	329.4	289	350	(135)	(65)	(461)
Arthur Kill ST 3	518.4	(41.7)	476.7	141	203	(282)	(212)	(608)
Brooklyn Navy Yard	250.8	(20.2)	230.6	388	449	(36)	34	(362)
Astoria 2, 3, & 5	899.5	(72.3)	827.2	(209)	(147)	(633)	(563)	(959)
Astoria 2	159.5	(12.8)	146.7	472	533	48	118	(278)
Astoria 3	369.9	(29.7)	340.2	278	340	(146)	(76)	(472)
Astoria 5	370.1	(29.7)	340.4	278	339	(146)	(76)	(472)
Ravenswood ST 01, 02, & 03 (2)	1,723.3	(138.5)	1,584.8	(729)	(667)	(1,152)	(1,157)	(1,553)
Ravenswood ST 01	360.3	(29.0)	331.3	287	348	(137)	(67)	(463)
Ravenswood ST 02	375.1	(30.1)	345.0	273	335	(150)	(80)	(476)
Ravenswood ST 03 (2)	987.9	(79.4)	908.5	(52)	9	(476)	(481)	(877)
Ravenswood CC 04	223.9	(18.0)	205.9	412	474	(11)	59	(337)
East River 1, 2, 6, & 7	615.5	(49.5)	566.0	52	114	(371)	(301)	(697)
East River 1	152.1	(12.2)	139.9	478	540	55	125	(271)
East River 2	153.9	(12.4)	141.5	477	538	53	123	(273)
East River 6	132.7	(10.7)	122.0	496	558	73	143	(253)
East River 7	176.8	(14.2)	162.6	456	517	32	102	(294)
Linden Cogen	715.0	(57.5)	657.5	(39)	22	(463)	(393)	(789)
Gowanus 2-1 through 3-8 (3)	263.5	(21.2)	242.3	376	437	-	-	-
Gowanus 2-1 (3)	16.2	(1.3)	14.9	603	665	-	-	-
Gowanus 2-2 (3)	17.2	(1.4)	15.8	602	664	-	-	-
Gowanus 2-3 (3)	18.9	(1.5)	17.4	601	662	-	-	-
Gowanus 2-4 (3)	16.8	(1.3)	15.5	603	664	-	-	-
Gowanus 2-5 (3)	17.4	(1.4)	16.0	602	664	-	-	-
Gowanus 2-6 (3)	18.8	(1.5)	17.3	601	663	-	-	-
Gowanus 2-7 (3)	18.4	(1.5)	16.9	601	663	-	-	-
Gowanus 2-8 (3)	17.5	(1.4)	16.1	602	664	-	-	-
Gowanus 3-1 (3)	17.0	(1.4)	15.6	603	664	-	-	-
Gowanus 3-2 (3)	17.2	(1.4)	15.8	602	664	-	-	-
Gowanus 3-3 (3)	18.0	(1.4)	16.6	602	663	-	-	-
Gowanus 3-4 (3)	16.4	(1.3)	15.1	603	665	-	-	-
Gowanus 3-5 (3)	18.0	(1.4)	16.6	602	663	-	-	-
Gowanus 3-7 (3)	18.1	(1.5)	16.6	602	663	-	-	-
Gowanus 3-8 (3)	17.6	(1.4)	16.2	602	664	-	-	-
Gowanus 5 & 6 (4)	79.9	(6.4)	73.5	545	606	121	191	-
Gowanus 5 (4)	40.0	(3.2)	36.8	581	643	158	228	-
Gowanus 6 (4)	39.9	(3.2)	36.7	582	643	158	228	-
Kent (4)	40.0	(3.2)	36.8	581	643	158	228	-
Pouch (4)	39.2	(3.1)	36.1	582	644	159	229	-
Hellgate 1 & 2 (4)	79.5	(6.4)	73.1	545	607	122	192	-
Hellgate 1 (4)	39.9	(3.2)	36.7	582	643	158	228	-
Hellgate 2 (4)	39.6	(3.2)	36.4	582	643	158	228	-
Harlem River 1 & 2 (4)	79.5	(6.4)	73.1	545	607	122	192	-
Harlem River 1 (4)	39.9	(3.2)	36.7	582	643	158	228	-

New York City								
Year				2027	2028	2029	2030	2031
New York City Transmission Security Margin Summer Peak - Baseline Expected Summer Weather, Normal Transfer Criteria (MW)(1)				618	680	195	265	(131)
Unit Name	Summer DMNC (MW)	NYCA Zonal Average De-Rate (MW)	Summer De-Rated Capability (MW)	Transmission Security Margin Considering Impact of Generator Outage (Retire, Mothball, IIFO)				
Harlem River 2 (4)	39.6	(3.2)	36.4	582	643	158	228	-
Vernon Blvd 2 & 3 (4)	79.9	(6.4)	73.5	545	606	121	191	-
Vernon Blvd 2 (4)	40.0	(3.2)	36.8	581	643	158	228	-
Vernon Blvd 3 (4)	39.9	(3.2)	36.7	582	643	158	228	-
Narrows 1-1 through 2-8 (3)	242.3	(19.5)	222.8	395	457	-	-	-
Narrows 1-1 (3)	17.6	(1.4)	16.2	602	664	-	-	-
Narrows 1-2 (3)	16.4	(1.3)	15.1	603	665	-	-	-
Narrows 1-3 (3)	16.7	(1.3)	15.4	603	664	-	-	-
Narrows 1-4 (3)	17.1	(1.4)	15.7	602	664	-	-	-
Narrows 1-5 (3)	18.0	(1.4)	16.6	602	663	-	-	-
Narrows 1-6 (3)	15.0	(1.2)	13.8	604	666	-	-	-
Narrows 1-7 (3)	17.5	(1.4)	16.1	602	664	-	-	-
Narrows 1-8 (3)	15.7	(1.3)	14.4	604	665	-	-	-
Narrows 2-2 (3)	16.3	(1.3)	15.0	603	665	-	-	-
Narrows 2-3 (3)	16.4	(1.3)	15.1	603	665	-	-	-
Narrows 2-4 (3)	18.1	(1.5)	16.6	602	663	-	-	-
Narrows 2-5 (3)	20.2	(1.6)	18.6	600	661	-	-	-
Narrows 2-6 (3)	20.0	(1.6)	18.4	600	661	-	-	-
Narrows 2-8 (3)	17.3	(1.4)	15.9	602	664	-	-	-
Astoria CC 1 & 2	474.0	(38.1)	435.9	182	244	(241)	(171)	(567)
Astoria CC 1	237.0	(19.0)	218.0	400	462	(23)	47	(349)
Astoria CC 2	237.0	(19.0)	218.0	400	462	(23)	47	(349)
Astoria East Energy CC1 & CC2	589.2	(47.3)	541.9	76	138	(347)	(277)	(673)
Astoria East Energy - CC1	294.6	(23.7)	270.9	347	409	(76)	(6)	(402)
Astoria East Energy - CC2	294.6	(23.7)	270.9	347	409	(76)	(6)	(402)
Astoria Energy 2 CC3 & CC4	570.0	(45.8)	524.2	94	156	(330)	(260)	(656)
Astoria Energy 2 - CC3	285.0	(22.9)	262.1	356	418	(67)	3	(393)
Astoria Energy 2 - CC4	285.0	(22.9)	262.1	356	418	(67)	3	(393)
Bayonne EC CTG1 through CTG10	592.7	(47.6)	545.1	73	135	(350)	(280)	(676)
Bayonne EC CTG1	59.5	(4.8)	54.7	564	625	140	210	(186)
Bayonne EC CTG2	54.6	(4.4)	50.2	568	630	144	214	(182)
Bayonne EC CTG3	58.8	(4.7)	54.1	564	626	141	211	(185)
Bayonne EC CTG4	61.1	(4.9)	56.2	562	624	138	208	(188)
Bayonne EC CTG5	59.9	(4.8)	55.1	563	625	140	210	(186)
Bayonne EC CTG6	60.5	(4.9)	55.6	563	624	139	209	(187)
Bayonne EC CTG7	57.0	(4.6)	52.4	566	627	142	212	(184)
Bayonne EC CTG8	60.5	(4.9)	55.6	563	624	139	209	(187)
Bayonne EC CTG9	60.4	(4.9)	55.5	563	624	139	209	(187)
Bayonne EC CTG10	60.4	(4.9)	55.5	563	624	139	209	(187)

Notes

- Utilizes the most severe margin result from the as-planned noncoincident or as-planned higher demand.
- In all years the most limiting contingency includes the loss of Ravenswood 3. For this calculation the margin based on the loss of CHPE and one transmission element is utilized
- Unit is modeled out of service beginning in 2029 in the baseline margin calculation.
- Unit is modeled out of service beginning in 2031 in the baseline margin calculation.

Figure 41: AOI - Long Island Transmission Security Margin

Long Island								
Year				2027	2028	2029	2030	2031
Long Island Transmission Security Margin Summer Peak - Baseline Expected Summer Weather, Normal Transfer Criteria (MW)(1)				329	396	348	2,246	2,149
Unit Name	Summer DMNC (MW)	NYCA Zonal 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	(0.7)	4.9	324	391	344	2,242	2,144
Greenport IC 4	1.0	(0.1)	0.9	328	395	348	2,246	2,148
Greenport IC 5	1.5	(0.2)	1.3	327	395	347	2,245	2,148
Greenport IC 6	3.1	(0.4)	2.7	326	393	346	2,244	2,146
Freeport 1-2, 1-3, & 2-3	21.5	(2.6)	18.9	310	377	330	2,228	2,130
Freeport 1-2	2.5	(0.3)	2.2	327	394	346	2,244	2,147
Freeport 1-3	3.0	(0.4)	2.6	326	394	346	2,244	2,146
Freeport 2-3	16.0	(2.0)	14.0	315	382	334	2,232	2,135
Charles P Keller 09 through 14	13.4	(1.6)	11.8	317	384	337	2,235	2,137
Charles P Keller 09	1.6	(0.2)	1.4	327	395	347	2,245	2,148
Charles P Keller 10	1.6	(0.2)	1.4	327	395	347	2,245	2,148
Charles P Keller 11	2.4	(0.3)	2.1	327	394	346	2,244	2,147
Charles P Keller 12	2.5	(0.3)	2.2	327	394	346	2,244	2,147
Charles P Keller 13	2.5	(0.3)	2.2	327	394	346	2,244	2,147
Charles P Keller 14	2.8	(0.3)	2.5	326	394	346	2,244	2,146
Wading River 1, 2, & 3	228.9	(28.0)	200.9	128	195	148	2,046	1,948
Wading River 1	77.4	(9.5)	67.9	261	328	280	2,178	2,081
Wading River 2	76.7	(9.4)	67.3	261	329	281	2,179	2,082
Wading River 3	74.8	(9.2)	65.6	263	331	283	2,181	2,083
Barrett ST 01 & 02	325.3	(39.9)	285.4	43	111	63	1,961	1,863
Barrett ST 01	144.3	(17.7)	126.6	202	270	222	2,120	2,022
Barrett ST 02	181.0	(22.2)	158.8	170	237	190	2,088	1,990
Barrett GT 01 through 12	259.4	(31.8)	227.6	101	169	121	2,019	1,921
Barrett GT 01	14.2	(1.7)	12.5	316	384	336	2,234	2,136
Barrett GT 02	14.3	(1.8)	12.5	316	384	336	2,234	2,136
Barrett 03	13.8	(1.7)	12.1	317	384	336	2,234	2,137
Barrett 04	15.1	(1.9)	13.2	316	383	335	2,233	2,136
Barrett 05	12.7	(1.6)	11.1	318	385	337	2,235	2,138
Barrett 06	14.0	(1.7)	12.3	316	384	336	2,234	2,137
Barrett 08	13.3	(1.6)	11.7	317	385	337	2,235	2,137
Barrett 09	40.4	(4.9)	35.5	293	361	313	2,211	2,113
Barrett 10	41.3	(5.1)	36.2	293	360	312	2,210	2,113
Barrett 11	40.0	(4.9)	35.1	294	361	313	2,211	2,114
Barrett 12	40.3	(4.9)	35.4	293	361	313	2,211	2,114
Northport 1, 2, 3, and 4	1,452.0	(177.9)	1,274.1	(945)	(878)	(926)	972	875
Northport 1	363.0	(44.5)	318.5	10	78	30	1,928	1,830
Northport 2	363.0	(44.5)	318.5	10	78	30	1,928	1,830
Northport 3	363.0	(44.5)	318.5	10	78	30	1,928	1,830
Northport 4	363.0	(44.5)	318.5	10	78	30	1,928	1,830
Port Jefferson GT 02 & 03	78.1	(9.6)	68.5	260	328	280	2,178	2,080
Port Jefferson GT 02	38.8	(4.8)	34.0	295	362	314	2,212	2,115
Port Jefferson GT 03	39.3	(4.8)	34.5	294	362	314	2,212	2,114

Long Island								
Year				2027	2028	2029	2030	2031
Long Island Transmission Security Margin Summer Peak - Baseline Expected Summer Weather, Normal Transfer Criteria (MW)(1)				329	396	348	2,246	2,149
Unit Name	Summer DMNC (MW)	NYCA Zonal Average De-Rate (MW)	Summer De-Rated Capability (MW)	Transmission Security Margin Considering Impact of Generator Outage (Retire, Mothball, IIFO)				
Port Jefferson 3 & 4	359.8	(44.1)	315.7	13	80	33	1,931	1,833
Port Jefferson 3	178.8	(21.9)	156.9	172	239	192	2,090	1,992
Port Jefferson 4	181.0	(22.2)	158.8	170	237	190	2,088	1,990
Hempstead (RR)	74.5	(9.1)	65.4	263	331	283	2,181	2,084
Glenwood GT 02, 03, 04, & 05	179.9	(22.0)	157.9	171	238	191	2,089	1,991
Glenwood GT 02	48.3	(5.9)	42.4	286	354	306	2,204	2,107
Glenwood GT 03	53.0	(6.5)	46.5	282	350	302	2,200	2,102
Glenwood GT 04	38.4	(4.7)	33.7	295	362	315	2,213	2,115
Glenwood GT 05	40.2	(4.9)	35.3	293	361	313	2,211	2,114
Holtsville 01 through 10	510.1	(62.5)	447.6	(119)	(51)	(99)	1,799	1,701
Holtsville 01	53.0	(6.5)	46.5	282	350	302	2,200	2,102
Holtsville 02	52.0	(6.4)	45.6	283	351	303	2,201	2,103
Holtsville 03	46.9	(5.7)	41.2	288	355	307	2,205	2,108
Holtsville 04	50.9	(6.2)	44.7	284	352	304	2,202	2,104
Holtsville 05	49.4	(6.1)	43.3	285	353	305	2,203	2,106
Holtsville 06	52.7	(6.5)	46.2	283	350	302	2,200	2,103
Holtsville 07	50.0	(6.1)	43.9	285	352	305	2,203	2,105
Holtsville 08	49.6	(6.1)	43.5	285	353	305	2,203	2,105
Holtsville 09	52.3	(6.4)	45.9	283	350	303	2,201	2,103
Holtsville 10	53.3	(6.5)	46.8	282	349	302	2,200	2,102
Shoreham 1	46.0	(5.6)	40.4	288	356	308	2,206	2,109
Shoreham 2	16.7	(2.0)	14.7	314	382	334	2,232	2,134
Shoreham GT3 & GT4	82.7	(10.1)	72.6	256	324	276	2,174	2,076
Shoreham GT3	41.4	(5.1)	36.3	292	360	312	2,210	2,113
Shoreham GT4	41.3	(5.1)	36.2	293	360	312	2,210	2,113
East Hampton GT 01, 2, 3, & 4	23.5	(2.9)	20.6	308	376	328	2,226	2,128
East Hampton GT 01	18.1	(2.2)	15.9	313	380	333	2,231	2,133
East Hampton 2	1.8	(0.2)	1.6	327	395	347	2,245	2,147
East Hampton 3	1.8	(0.2)	1.6	327	395	347	2,245	2,147
East Hampton 4	1.8	(0.2)	1.6	327	395	347	2,245	2,147
Southold 1	9.8	(1.2)	8.6	320	388	340	2,238	2,140
S Hampton 1	8.1	(1.0)	7.1	322	389	341	2,239	2,142
Freeport CT 1 & 2	88.7	(10.9)	77.8	251	318	271	2,169	2,071
Freeport CT 1	45.7	(5.6)	40.1	289	356	308	2,206	2,109
Freeport CT 2	43.0	(5.3)	37.7	291	358	311	2,209	2,111
Flynn	139.5	(17.1)	122.4	206	274	226	2,124	2,027
Greenport GT1	54.5	(6.7)	47.8	281	348	301	2,199	2,101
Far Rockaway GT1 & GT2	94.9	(11.6)	83.3	246	313	265	2,163	2,066
Far Rockaway GT1	48.9	(6.0)	42.9	286	353	306	2,204	2,106
Far Rockaway GT2	46.0	(5.6)	40.4	288	356	308	2,206	2,109
Bethpage	46.0	(5.6)	40.4	288	356	308	2,206	2,109
Bethpage 3	75.0	(9.2)	65.8	263	330	283	2,181	2,083

Long Island								
Year				2027	2028	2029	2030	2031
Long Island Transmission Security Margin Summer Peak - Baseline Expected Summer Weather, Normal Transfer Criteria (MW)(1)				329	396	348	2,246	2,149
Unit Name	Summer DMNC (MW)	NYCA Zonal Average De-Rate (MW)	Summer De-Rated Capability (MW)	Transmission Security Margin Considering Impact of Generator Outage (Retire, Mothball, IIFO)				
Bethpage GT4	43.8	(5.4)	38.4	290	358	310	2,208	2,110
Brentwood (2)	45.0	(5.5)	39.5	289	357	309	2,207	-
Pilgrim GT1 & GT2	84.9	(10.4)	74.5	254	322	274	2,172	2,074
Pilgrim GT1	42.0	(5.1)	36.9	292	359	312	2,210	2,112
Pilgrim GT2	42.9	(5.3)	37.6	291	359	311	2,209	2,111
Caithness_CC_1	321.8	(39.4)	282.4	46	114	66	1,964	1,867
Islip (RR)	7.5	(0.9)	6.6	322	390	342	2,240	2,142
Babylon (RR)	15.8	(1.9)	13.9	315	382	335	2,233	2,135
Huntington (RR)	24.8	(3.0)	21.8	307	374	327	2,225	2,127

Notes

1. Utilizes the most severe margin result from the as-planned noncoincident or as-planned higher demand.
2. Unit is modeled out of service beginning in 2031 in the baseline margin calculation.