Short-Term Assessment of Reliability: 2026 Quarter 1

A Report by the
New York Independent System Operator

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Table of Contents

Executive Summary

This report sets forth the 2026 Quarter 1 Short-Term Assessment of Reliability ("STAR") findings for the five-year study period of January 15, 2026, through January 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 deactivation of Danskammer units 1-4 as Initiating Generators[1] (572 MW total nameplate) is evaluated in this STAR, resulting in the identification of a Near-Term Reliability Need in the Lower Hudson Valley.

The NYISO is also issuing the *Short-Term Reliability Process Report: 2026-2030 Generator Deactivation Reliability Needs (2025 Quarter 3 STAR)*, summarizing the evaluation and selection of solutions to address generator deactivation reliability needs in New York City, Long Island, and the Lower Hudson Valley, as further discussed in this report.

Starting with the 2025 Quarter 3 STAR, recent quarterly reports observe continued supply deficiencies through the entire five-year horizon of the assessment (*i.e.*, 2026 to 2030) 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- 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.

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.

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

While the Short-Term Reliability Process applies only to the first five years of the planning horizon, this report provides additional information on potential longer-term reliability issues. The 2026 Reliability Needs Assessment (RNA) will evaluate the reliability of the New York bulk electric grid over the ten-year planning horizon, with a focus on 2030-2036, considering updated forecasts of grid demand according to the 2026 Gold Book, planned transmission upgrades, and projected changes to the generation fleet. As presented in the recent 2025-2034 Comprehensive Reliability Plan (CRP), the NYISO proposes to incorporate aging generation risk to better capture the likelihood of future resource unavailability and identify emerging reliability needs beyond the short-term horizon.[2]

New York City

This STAR continues to observe a Bulk Power Transmission Facility ("BPTF") deficiency identified in the 2025 Quarter 3 STAR in New York City (Zone J). Based on the key study assumptions presented to stakeholders at the start of this STAR and without the completion and energization of the future planned projects identified in the April 15, 2026 Short-Term Reliability Process Report to address the New York City Need there are no changes to the scope, scale, or nature of the need that the 2025 Quarter 3 STAR identified in New York City and for which the NYISO solicited solutions on November 10, 2025. While the planned projects identified in the Short-Term Reliability Process Report are advancing in their development, their completion is subject to inherent risks commonly observed in large infrastructure projects that may impact timely completion and energization.

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

New York City BPTF Need

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

[2] 2025-2034 Comprehensive Reliability Plan (here)

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 in accordance with the Department of Environmental Conservation ("DEC") Peaker Rule 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.[3] 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. As described in the Short-Term Reliability Process Report, the NYISO now has submitted 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, the maximum permissible permit extension date allowed under the Peaker Rule. AlphaGen, the owner, has proposed to withdraw the generator deactivation notices for these generators.

The retention of the Gowanus and Narrows barges alone is insufficient to address the New York City need, and in the absence of other projects the deficiency would remain unresolved and require reliance on emergency actions to maintain reliability. As planned projects enter service, including Champlain Hudson Power Express ("CHPE") and other planned projects, the margins in New York City improve substantially over the short-term horizon, but diminish again over the longer-term with demand growth and the risk of aging generation.

Long Island

This STAR continues to observe the BPTF and non-BPTF deficiencies identified in the 2025 Quarter 3 STAR in Long Island (Zone K). Based on the key study assumptions presented to stakeholders at the start of this STAR and without the completion and energization of the future planned projects identified in the April 15, 2026 Short-Term Reliability Process Report to address the Long Island Needs there are no changes to the scope, scale, or nature of the Needs for which the NYISO solicited solutions on November 10, 2025.

The scope of the Long Island BPTF and non-BPTF Needs are shown in the tables below. The Long Island BPTF need was primarily driven by the deactivation of Pinelawn (82 MW nameplate) and the Far Rockaway GTs (121 MW nameplate total), while the Long Island Non-BPTF need was driven by the deactivation of the Far Rockaway GTs. The Interim Service Provider ("ISP")

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

agreement for the Pinelawn and Far Rockaway GTs became effective December 25, 2025.

Long Island BPTF Need

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

Long Island Non-BPTF Need (Far Rockaway Load Pocket)

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

As discussed in the Short-Term Reliability Process Report, 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. The NYISO will not offer an RMR agreement to Pinelawn Power 1 and the ISP agreement for this unit will terminate on May 15, 2026, after which the unit may deactivate.[4] On March 20, 2026 the Office of the State Comptroller approved a contract between LIPA and MPH Rockaway Peakers, LLC.[5] Following this approval, on March 30th, Hull St. Energy provided to the NYISO notice of their withdrawal of their Generator Deactivation Notices for Far Rockaway GT1 and GT2 effective hour beginning 1:00 on May 1, 2026. The ISP agreement for Far Rockaway 1 and Far Rockaway 2 will terminate on May 1, 2026.

[4] Consistent with Section 38.3.7 of the OATT, the earliest possible retirement date for Hull Street Energy, LLC generator, Pinelawn Power 1 is May 15, 2026. Hull Street Energy, LLC must complete all required NYISO administrative process and procedures prior to retirement of its generating unit. See NYISO Technical Bulletin 185. The NYISO's determination in this Short-Term Reliability Process does not relieve Hull Street Energy, LLC of any obligations they have with respect to its Generators participation in the NYISO markets. Hull Street will be required to repay study cost in accordance with Section 38.14 of the OATT for its Far Rockaway GTs. If Hull Street Energy, LLC rescinds its Generator Deactivation Notice or does not retire Pinelawn within 730 days of July 15, 2025, then Hull Street 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.

[5] https://www.osc.ny.gov/open-book-new-york

Lower Hudson Valley

Consistent with the findings of the 2025 Quarter 3 and Quarter 4 STARs, this STAR continues to find a Generator Deactivation Reliability Need in the Lower Hudson Valley locality. In prior STARs, the Lower Hudson Valley deficiency was primarily an exacerbation of the New York City BPTF Need and was also impacted by the BPTF Need identified in Zone K. However, the proposed retirement of Danskammer 1-4 exacerbates the deficiency.

With the proposed retirement of Danskammer 1-4, the Generator Deactivation Reliability Need is now also a Near-Term Reliability Need as deficiencies arise in summer 2027. The need is also driven by demand forecasts based on expected weather, expected generator availability, transmission limitations, and risks associated with the availability of key future planned projects. The observed deficiencies in this locality are also driven in part by the RECO demand that is served by PJM. Electricity from PJM flows across the New York State Transmission System to serve RECO.

The following table provides the magnitude and duration of the BPTF deficiency observed in this STAR throughout the study period for this STAR based on the key study assumptions presented to stakeholders at the start of this study.

Lower Hudson Valley BPTF Deficiencies:

Summer Peak	2026	2027	2028	2029	2030
MW Deficiency	None	17-27	69-184	121-383	202-639
Duration (hours)	None	1	3	3-4	3-6
MWh	None	17-27	396-756	521-1,446	718-2,663

In consideration of the solution selection for New York City and Long Island discussed in the April 15, 2026 Short-Term Reliability Process Report, there are sufficient solutions to address the Lower Hudson Valley deficiency. Upon the withdrawal of the deactivation notices for the Gowanus and Narrows barges, the deficiencies in summer 2027 and 2028 would be addressed, but the deficiencies in 2029 and 2030 would continue to be observed. The extension of the Gowanus and Narrows barges would also help to address the Lower Hudson Valley deficiency whereas retaining Danskammer 1-4 would not help alleviate the New York City Need as the Danskammer units are outside of Zone J.

As the Lower Hudson Valley deficiency would be resolved in whole or in part by the retention of Danskammer 1-4 and the deficiencies are observed within the first three years of the short-term horizon, the Lower Hudson Valley deficiency is a Generator Deactivation Reliability Need and a

Near-Term Reliability Need. Because permanent solutions to the Generator Deactivation Reliability Need have not entered service yet, the NYISO has determined that Danskammer 1-4 cannot deactivate until at least August 1, 2026 and may be required to remain in-service until at least January 15, 2027 if reliability needs persist.[6]

Reliability Assessment

Included in this STAR is the generator deactivation assessment for the retirement of Danskammer 1-4. The NYISO performed a transmission security assessment of the BPTF and identified an exacerbation of an existing reliability need on the BPTF in the Lower Hudson Valley during the STAR study period. Central Hudson performed a deactivation assessment to evaluate the reliability of the local non-BPTF system with the Danskammer 1-4 retirement. A generator deactivation reliability need was identified by the NYISO. Central Hudson did not identify a non-BPTF generator deactivation reliability need in this STAR.

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

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[6] If planned projects fail to timely enter service or otherwise prove insufficient, and the NYISO determines it requires additional solutions to address Lower Hudson Valley needs arising in 2029 and 2030, then the NYISO will conduct a solicitation pursuant to Section 38.4.8.1(c) of the OATT to obtain additional solutions to the identified needs, and may execute an RMR Agreement with Danskammer to allow sufficient time to complete the solicitation process, and/or to address the 2029 and 2030 needs if the solicitation does not produce other viable and sufficient solutions.

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")[7] 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."[8] 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 1 findings for the study period from the STAR Start Date (January 15, 2026) through January 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.[9]

[7] OATT Section 38.1 contains the tariff definition of a "Short-Term Reliability Process Need."
[8] OATT Section 38.1 contains the tariff definition of a "Near-Term Reliability Need." *See also*, OATT Section 38.3.6.
[9] NYISO Reliability Planning Process Manual, July 11, 2022. *See:* https://www.nyiso.com/documents/20142/2924447/rpp_mnl.pdf

Assumptions

The NYISO evaluated the study period using the most recent Reliability Planning Process assumptions and data available as of January 15, 2026 (*i.e.,* the day before the January 15, 2026 Q1 STAR start date). In accordance with the Reliability Planning Process inclusion rules,[10] 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 2024 RNA, along with several updates to key study assumptions that are provided below. Consistent with the obligations under its tariffs, the NYISO provided information to stakeholders on the modeling assumptions employed in this assessment. Details regarding the study assumptions were reviewed with stakeholders at the joint Electric System Planning Working Group ("ESPWG")/Transmission Planning Advisory Subcommittee ("TPAS") meeting on February 3, 2026. The meeting materials are posted on the NYISO's website.[11]

Generation Assumptions

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

Generator Deactivation Notices

For this STAR, the deactivating generators included in this assessment are listed in Figure 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.[12]

Figure 1: 2026 Quarter 1 STAR Generator Deactivations

Owner/ Operator	Plant Name	PTID	Zone	Nameplate (MW)	Status	Proposed Deactivation/IIFO Date
Danskammer Energy, LLC	Danskammer 1-4	23586, 23589, 23590, 23591	G	532	Retire	8/1/2026

[10] *See* NYISO Reliability Planning Process Manual Section 3.
[11] Short-Term Assessment of Reliability: 2026 Q1 Key Study Assumptions, ESPWG/TPAS, February 3, 2026 (here)
[12] *See* https://www.nyiso.com/short-term-reliability-process then Generator Deactivation Notices/Planned Retirement Notices or Generator Deactivation Notices/IIFO Notifications.

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

In 2019, the New York State Department of Environmental Conservation ("DEC") adopted a regulation to limit nitrogen oxides (NOx) emissions from simple-cycle combustion turbines (referred to as the "Peaker Rule").[13] Since May 2023, over 1,600 MW of peaker units have deactivated or limited their operations. A list of peaker generators that were expected to be unavailable in the summer ozone season by May 1, 2025 is provided in Figure 2.

The DEC regulations include a provision to allow an affected generator to continue to operate for up to two years, with a possible further two-year extension, after the compliance deadline if the generator is designated by the NYISO or by the local transmission owner as needed to resolve a reliability need until a permanent solution is in place. Consistent with the DEC's regulations and detailed in the Short-Term Reliability Process Report it issued on November 20, 2023, the NYISO had designated the Gowanus 2 & 3 and Narrows 1 & 2 generators (32 units total) to temporarily continue operation beyond May 2025 until permanent solutions are in place, for an initial period of up to two years (until May 1, 2027). In the April 15, 2026 Short-Term Reliability Process Report, the NYISO also provides details on the second extension with the DEC for these units until May 1, 2029.

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

Figure 2: Status Changes Due to DEC Peaker Rule

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

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

Generator Return-to-Service

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

Generator Additions

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

The NYISO continues to monitor the status of the planned Empire Wind and Sunrise Wind offshore wind projects, considering the December 22, 2025, orders by the Bureau of Ocean and Energy Management (BOEM) to suspend all ongoing activities and the subsequent preliminary injunctions to stay the suspension orders while the court considers the merits of the orders.

Additional Generation Updates

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

Demand Assumptions

This assessment primarily utilizes the demand forecasts from the 2025 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 NYISO recently revised demand forecasts[14] to be published in the 2026 Gold Book and reflected in future reliability planning studies.

For this assessment, certain load projects in Zone K, which were included in the expected weather Gold Book forecasts have been removed from the model based on status updates regarding these load projects provided by LIPA. The 2025 Gold Book includes three coincident demand forecasts: Lower Demand, Baseline, and Higher Demand. Each of these forecasts contains differing inputs on economic, electrification, and large load assumptions, but the weather conditions are the same across each of these forecast which are summarized in Appendix C (Figure 38 and Figure 39). The behind-the-meter (BTM) solar, BTM distributed generation, and energy storage forecasts are consistent across all forecasts. Further details of the Higher Demand and Lower Demand forecasts are summarized as follows:

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

The result of the differences in the forecasts is that the Higher Demand and Lower Demand forecasts produce lower and upper bounds around the baseline forecast. Figure 3 through Figure 6 provide visual depictions of the three forecasts for the summer peak for Lower Hudson Valley, New York City, Long Island, and Statewide. The NYISO also includes an assessment of the Lower Hudson Valley, New York City, and Long Island localities non-coincident peak in the identification of bulk system generator deactivation reliability needs.

One key assumption in this STAR is that cryptocurrency mining and hydrogen production large loads will be flexible during system peak demand conditions. This assumption, based on communications with load developers and recent operating experience, results in up to

[14] Draft 2026 Gold Book forecasts were provided to Stakeholders at the April 7, 2026 TPAS/ESPWG/LFTF (here)

approximately 685 MW of large load reduction during the summer and winter peak periods by 2026. The trend of large load development, and their operating characteristics, requires continuous monitoring as they enter service. The NYISO will continue to coordinate with load developers and Transmission Owners.

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

Figure 3: Lower Hudson Valley Demand Forecasts (2025 Gold Book)

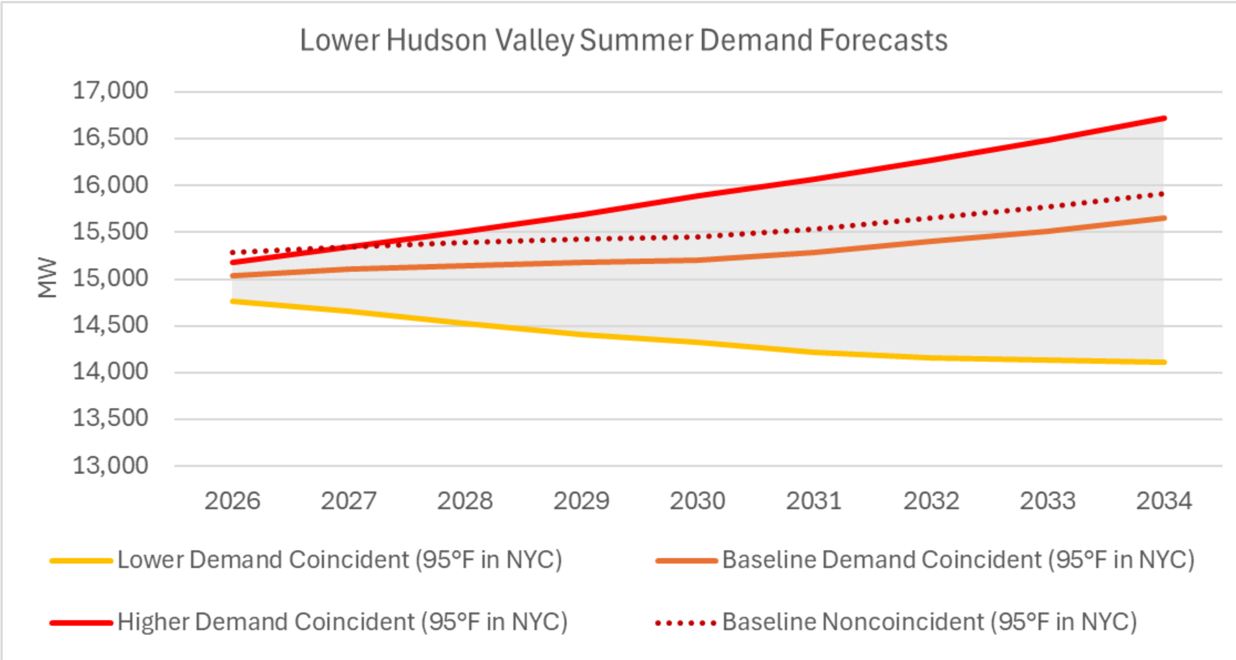


Figure 4: New York City Demand Forecasts (2025 Gold Book)

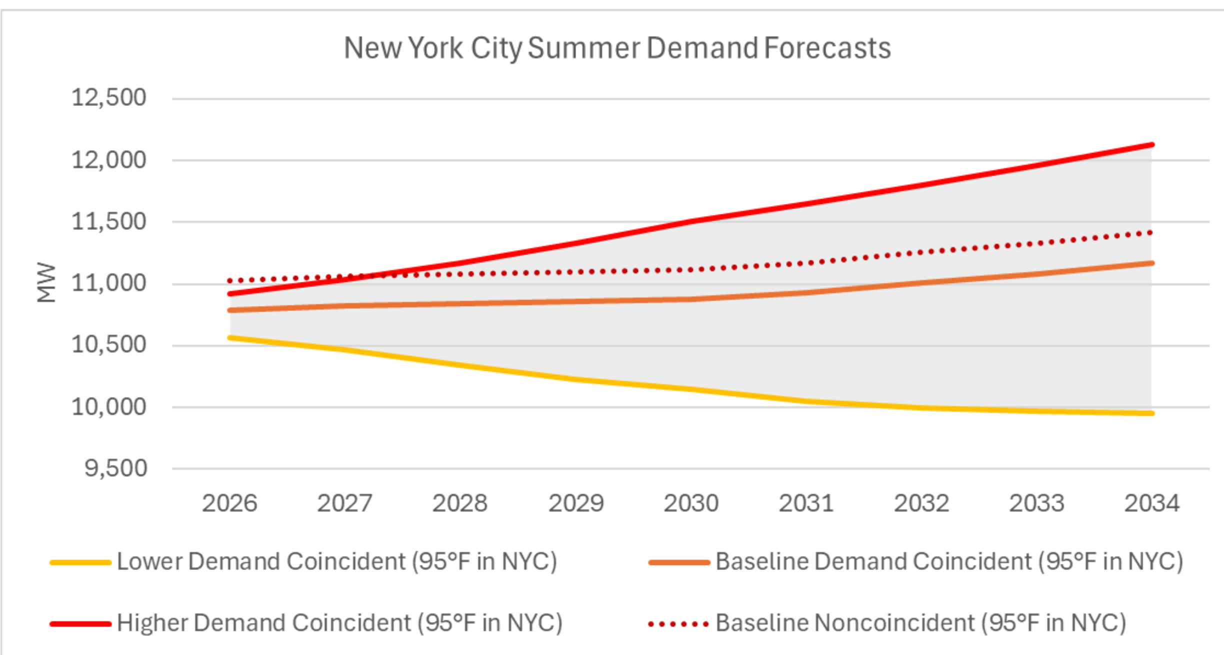


Figure 5: Long Island Demand Forecasts (2025 Gold Book)

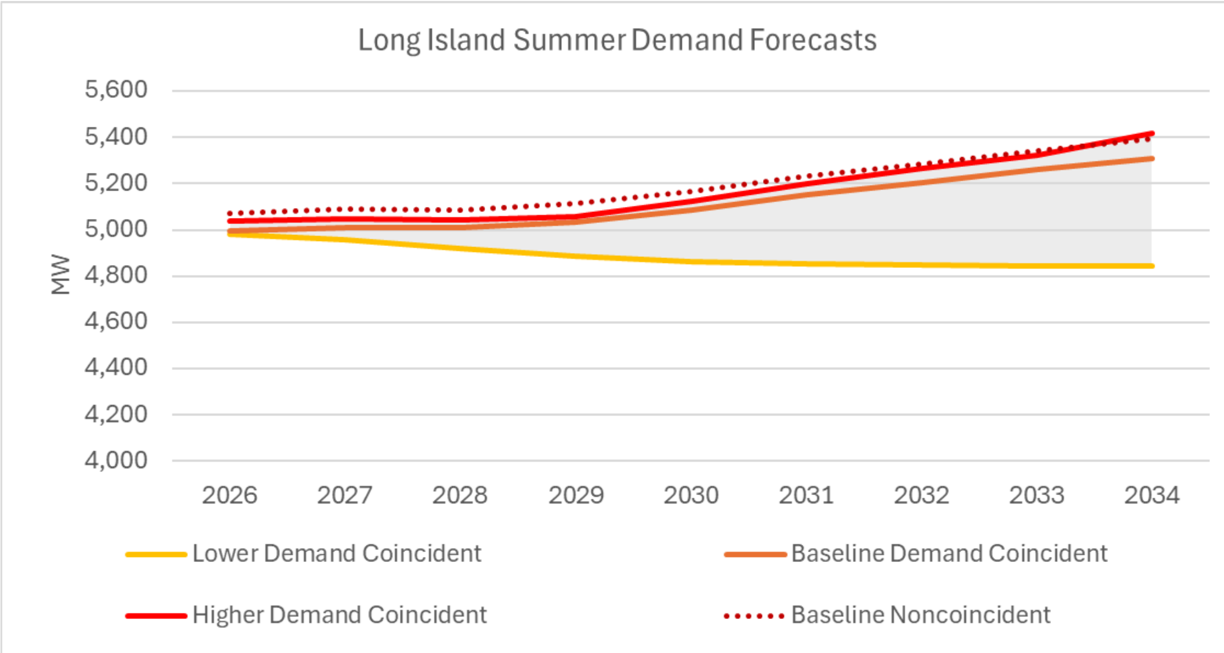
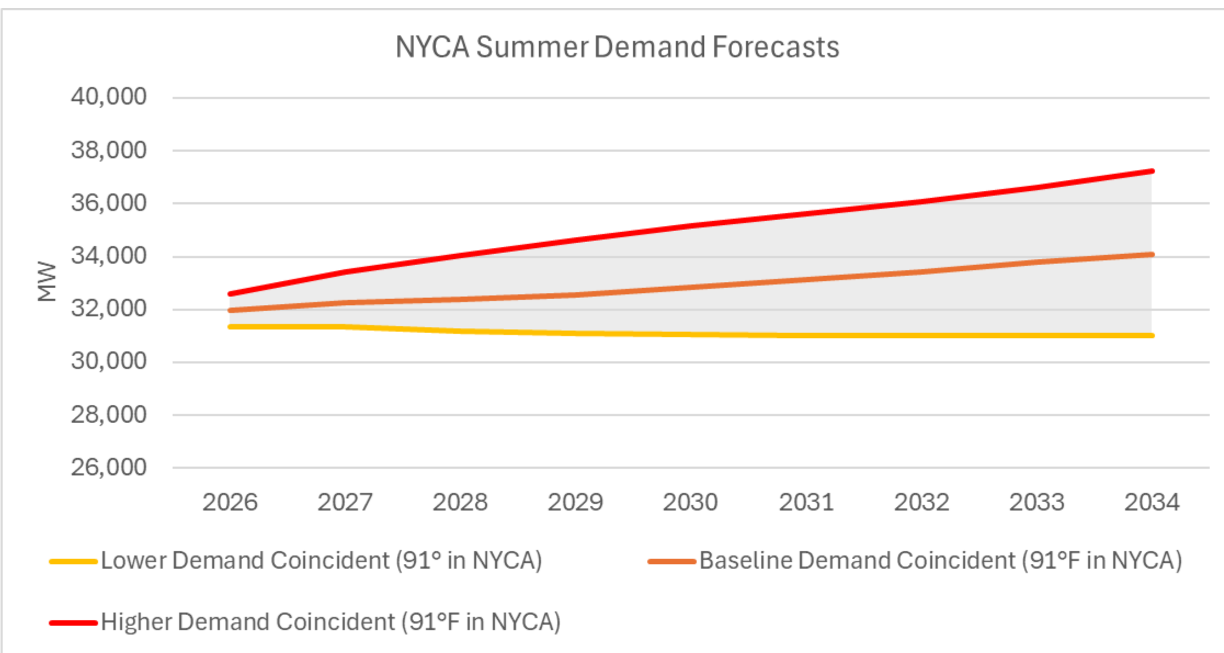


Figure 6: NYCA Demand Forecasts (2025 Gold Book)



Transmission Assumptions

Existing Transmission

The transmission assumptions utilized in this assessment are similar to those used for the 2024 RNA. Figure 7 lists the existing transmission outage assumptions.

Figure 7: Transmission Outage Assumptions

From	To	kV	ID	Out-of-Service Through	
				Prior STAR	Current STAR
Marion	Farragut	345	B3402	Long-Term	
Marion	Farragut	345	C3403	Long-Term	
Plattsburgh (1)	Plattsburgh	230/115	AT1	9/2026	
Stolle Rd	Stolle Rd	115	T11-52	12/2025	7/2026
Station 23	Station 42	115	920	12/2025	12/2026
E13th Street		345/69	BK17	6/2027	
Oakdale (Cap Bank)		345	C1	-	6/2026

Notes

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

Proposed Transmission

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

Compared to the 2024 RNA, there are no changes to assumed firm transmission facilities, as captured in Section 7 of the 2025 Gold Book. Details of the proposed transmission assumptions included in the 2024 RNA are provided in Appendix C. Except for the projects listed in Figure 47 in Appendix C, all firm transmission plans captured in the 2025 Gold Book are included.

Findings

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

As explained below, this assessment continues to observe the deficiencies in New York City and Long Island which were first identified in the 2025 Quarter 3 STAR and that the scope, scale, and nature of these deficiencies are unchanged from the needs specified in the NYISO's November 2025 solution solicitation. However, with the proposed retirement of Danskammer 1-4, the Lower Hudson Valley need has been exacerbated and this STAR finds a Generator Deactivation Reliability Need that is also a Near-Term Reliability Need in this locality. While the Short-Term Reliability Process applies only to the first five years of the planning horizon, this report provides additional information on potential longer-term reliability issues (*see* "Reliability Margin Projections" later in this report). The 2026 RNA will evaluate the reliability of the New York bulk electric grid over the ten-year planning horizon, with a focus on 2030-2036, considering updated forecasts of grid demand according to the 2026 Gold Book, planned transmission upgrades, and projected changes to the generation fleet.

The findings in this section are based on the study assumptions presented to stakeholders at the February 3, 2026 TPAS/ESPWG meeting at the start of this STAR. Additional findings based on updates to the system plans, including those discussed in the April 15, 2026 Short-Term Reliability Process solutions report are discussed later in this report (*see* section, "Solutions to Previously Identified Short-Term Reliability Process Needs.")

Resource Adequacy Assessments

Resource adequacy is the ability of the electric system to supply the aggregate electrical demand and energy requirements of the firm load at all times, considering scheduled and reasonably expected unscheduled outages of system elements. The NYISO performs resource adequacy assessments on a probabilistic basis to capture the random nature of system element outages. If a system has sufficient transmission and generation, the probability of an unplanned disconnection of firm load is equal to or less than the system's standard, which is expressed as a loss of load expectation ("LOLE"). Consistent with the NPCC and NYSRC criterion, the New York

State bulk power system is planned to meet an LOLE that, at any given point in time, is less than or equal to an involuntary firm load disconnection that is not more frequent than once in every 10 years, or 0.1 event-days per year.

This assessment finds that the planned system through the study period meets the resource adequacy criterion. However, when considering reliance on the proposed projects ("status quo"), there is a NYCA LOLE violation (*i.e.,* above 0.1 event-days/year) observed in study year 2030, as shown in Figure 8.

Figure 8: 2026 Q1 STAR Resource Adequacy Results *(NYCA LOLE in event-days/year)*

Study Year	2026 Q1 STAR Base Case	2026 Q1 STAR Status Quo
2026	0.017	0.040
2027	0.013	0.071
2028	0.014	0.071
2029	0.015	0.076
2030	0.016	0.125

Additional resource adequacy simulations were performed on the status quo model to determine the amount of "perfect capacity[15]" in each zone (one zone at the time) that could be removed before the NYCA LOLE reaches 0.1 event-days/year as shown in Figure 9. These simulations offer another relative measure of how close the system is from not having adequate resources to reliably serve load.

Figure 9: Compensatory MW for the Status Quo Study year 2030

Zone	A	B	C	D	E	F	G	H	I	J	K
Compensatory MW	575									525	200

Further sensitivities found that the status quo 2030 NYCA annual LOLE will be within the criterion when either CHPE or Propel NY transmission project enter service. Additionally, other planned projects and selected solutions for the 2025 Q3 STAR Near Term Needs in Zones J and K

[15] In performing this analysis, because the LOLE is above criterion, "perfect capacity" (MW) is added one zone at a time to determine when a violation is removed. "Perfect capacity" is capacity that is not derated (*e.g.,* due to ambient temperature or unit unavailability), not subject to energy durations limitations (*i.e.*, available at maximum capacity every hour of the study year), and not tested for transmission security or interface impacts.

would also address these LOLE violations.

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"[16] 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.[17]

Transmission security margins are included in this assessment to identify plausible changes in conditions or assumptions that might adversely impact the reliability of the system. The transmission security margin is the ability to meet load plus losses and system reserve (*i.e.*, total capacity requirement) using NYCA generation, interchange, and including temperature-based generation derates (total resources). This assessment is performed using a deterministic approach through powerflow simulations combined with post-processing spreadsheet-based calculations.[18] For the transmission security margin assessment, margins are evaluated for the statewide system margin, as well as Lower Hudson Valley, New York City, and Long Island localities. This evaluation will identify a BPTF reliability when the margin is less than zero under expected weather, normal

[16] Attachment I of Transmission, Expansion, and Interconnection Manual.
[17] The RNA assumptions matrix is posted with the April 18, 2024 TPAS/ESPWG meeting materials, which are available here,
[18] At its June 23, 2022, meeting, the NYISO Operating Committee approved revisions to the Reliability Planning Process Manual that reflect the use of transmission security margins and other enhancements.

transfer criteria conditions for the Lower Hudson Valley, New York City, and Long Island localities. Additional information regarding reliability risks due to various uncertainties such as weather and climate, economic development, or federal and state regulatory and policy adoptions are provided in the 2025-2034 CRP.

For the purposes of identifying reliability needs on the BPTF using transmission security margin calculations, thermal generation MW capability is considered available based on NERC five-year class averages for the relevant type of unit.[19] 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

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

The first steady-state transmission security issue identified for the study period under expected summer peak conditions is a thermal violation on the Oakdale 345/115/34.5 kV transformer and Oakdale – North Endicott 115 kV transmission line. The violation occurs under N-1-1 conditions for contingency combinations that result in the loss of the Oakdale – Westover 115 kV and Oakdale – Northside 115 kV transmission lines. This overload is observed as early as summer 2026 and is addressed by the reconfiguration of the Oakdale 345 and 115 kV system along with a third Oakdale 345/115/34.5 kV transformer, which facilities are planned to be completed by winter 2031. Prior to completion of this project, NYSEG will utilize an interim operating procedure to address this overload. With the proposed interim load shed operating procedure and the local transmission plans, the NYISO will not solicit for solutions to address these issues but will continue to track the development of the local plans in the quarterly tracking process.

The second steady-state transmission security issue identified for the study period under expected summer peak conditions is a voltage violation at the Oakdale 115 kV station in expected summer peak conditions. The violation occurs under N-1-1 conditions for contingency combinations that result in loss of 345/115 kV transformers along with one of the two 345 kV lines

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

from Oakdale to Fraser or Watercure. NYSEG has two local transmission plans that help to address these issues. The first plan is a reconfiguration at the Fraser 115 kV station that provides stronger voltage support of the transmission system in the local area and is planned to be in service in summer 2027. The second local plan is a reconfiguration of the Oakdale 345 and 115 kV system and a third Oakdale 345/115/34.5 kV transformer, which are planned to be completed by winter 2031. Due to the observations in this STAR at Oakdale, NYSEG has proposed interim operating procedures including possible load shedding should the critical contingencies occur. With the proposed interim load shed operating procedure and the local transmission plans, the NYISO will not solicit for solutions to address these issues but will continue to track the development of the local plans in the quarterly tracking process.

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

Dynamics Assessment

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

Short Circuit Assessment

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

Transmission Security Margin Assessment

For the transmission security margin assessment, "tipping points" are evaluated for the Lower Hudson Valley, New York City, and Long Island localities as applicable to the identification of needs as the analysis is based on established Reliability Criteria. In the Lower Hudson Valley and Long Island localities, the BPTF system is designed to remain reliable in the event of two non-simultaneous outages (N-1-1). In the Con Edison service territory, the 345 kV transmission system and specific portions of the 138 kV transmission system are designed to remain reliable and return to normal ratings after the occurrence of two non-simultaneous outages (N-1-1-0). Updating findings due to planned system changes occurring following the start of this STAR are discussed later in this report in the "Solutions to Previously Identified Short-Term Reliability Process Needs" section.

The NYISO performed "status quo" evaluations prior to these system plans and other additional resources state-wide demonstrating their planned capabilities (approximately 4,400 MW of generation projects, as described in Figure 36 and Figure 37) during the planning horizon, while maintaining the assumption that demand grows as forecasted for expected weather, including large load development.

This STAR continues to observe the Generator Deactivation Reliability Needs in the New York City and Long Island localities as well as a change in scope and scale of the Lower Hudson Valley deficiency first observed in the 2025 Quarter 3 STAR. The deficiencies in each of these localities are only observed in the summer and will primarily be addressed through the completion and energization of specific planned projects. Details are provided below.

New York City Transmission Security Margin

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

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

- Gowanus-Greenwood 345/138 kV feeder – May 2026
- CHPE, 1,250 MW HVDC – by summer 2026
- Empire Wind, 816 MW offshore wind – July 2027

- Propel NY Public Policy Transmission Project – May 2030

The Generator Deactivation Reliability Need in Zone J is on the BPTF and is driven by the deactivation of Gowanus 2 & 2 and Narrows 1 & 2 generators ("Gowanus and Narrows barges") (672 MW nameplate total) in combination with other factors, such as: the range in the demand forecasts based on expected weather, expected generator availability, transmission limitations, and risks associated with the availability of key future planned projects. Further, these needs were observed within three years following the conclusion of the 365 days that follow the STAR start date, they were also identified as Near-Term Reliability Need (hereinafter, "New York City BPTF Need"). The New York City BPTF Need is shown in the table below. This need is observed under summer peak demand conditions if system plans are not completed. Winter transmission security margins in Zone J remain positive throughout the five-year horizon.

New York City BPTF Need

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

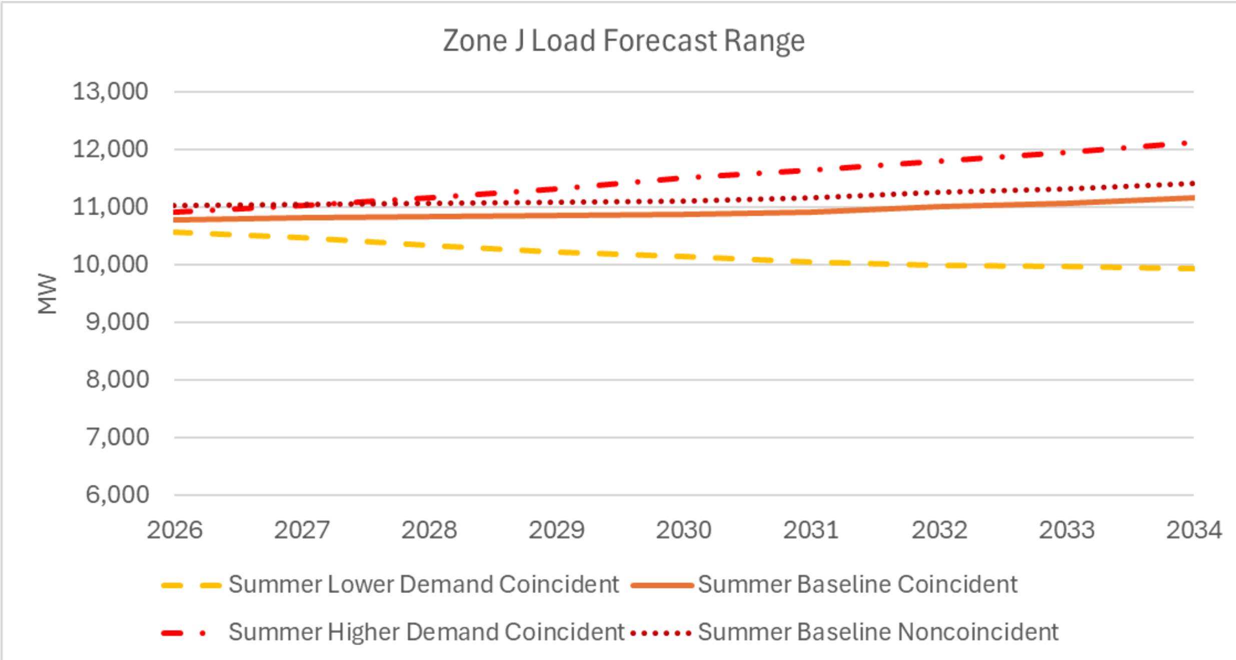
Once the future planned projects enter service and demonstrate their planned power capabilities, the margins within Zone J are expected to improve substantially, but the margins gradually erode thereafter as expected demand for electricity grows. As detailed in the 2025 Quarter 3 STAR, even assuming these future planned projects enter service according to their schedules and demonstrate their planned power capabilities and assuming no other generators become unavailable, Zone J would still have observed needs during the summer peak periods of 2029 and 2030. While these planned projects are advancing in their development, the completion is subject to inherent risks commonly observed among large infrastructure projects that may impact timely completion and energization.

As shown in Figure 13, if CHPE is not available for summer 2026, a deficiency of 650 MW over 8 hours (3,569 MWh) would persist without the retention of Gowanus and Narrows barges. Even with the planned inclusion of these future planned projects entering service according to schedule and demonstrate their planned power capabilities along with the use of battery projects that met inclusion rules in this STAR, and assuming no other generators are unavailable, in 2029, Zone J could still remain deficient by 37 MW over 4 hours (411 MWh), which grows to 148 MW over 5 hours (789 MWh) in 2030. Beyond 2030, these deficiencies would be further exacerbated with increasing demand for electricity. Figure 11 and Figure 12 depict the reliability margins for Zone J without any planned projects ("status quo") and as planned. The New York City summer peak margin is shown in Figure 13 showing the reliability impact of the status quo as well as future planned generation and transmission projects that have met the Reliability Planning Process inclusion rules.

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

As discussed in the April 15, 2026 Short-Term Reliability Process Report, additional projects have been identified and their impact is discussed later in this STAR in the section "solutions to previously identified short-term reliability needs." Until sufficient system plans within New York City are completed and demonstrate their planned power capabilities to address the identified reliability needs, the previously identified BPTF and non-BPTF deficiencies would persist without Gowanus and Narrows barges. While these planned projects are advancing in their development, the completion is subject to inherent risks commonly observed among large infrastructure projects that may impact timely completion and energization. Key challenges include permitting, material availability, construction complexities, and other unexpected factors.

Figure 10: Zone J Load Forecast



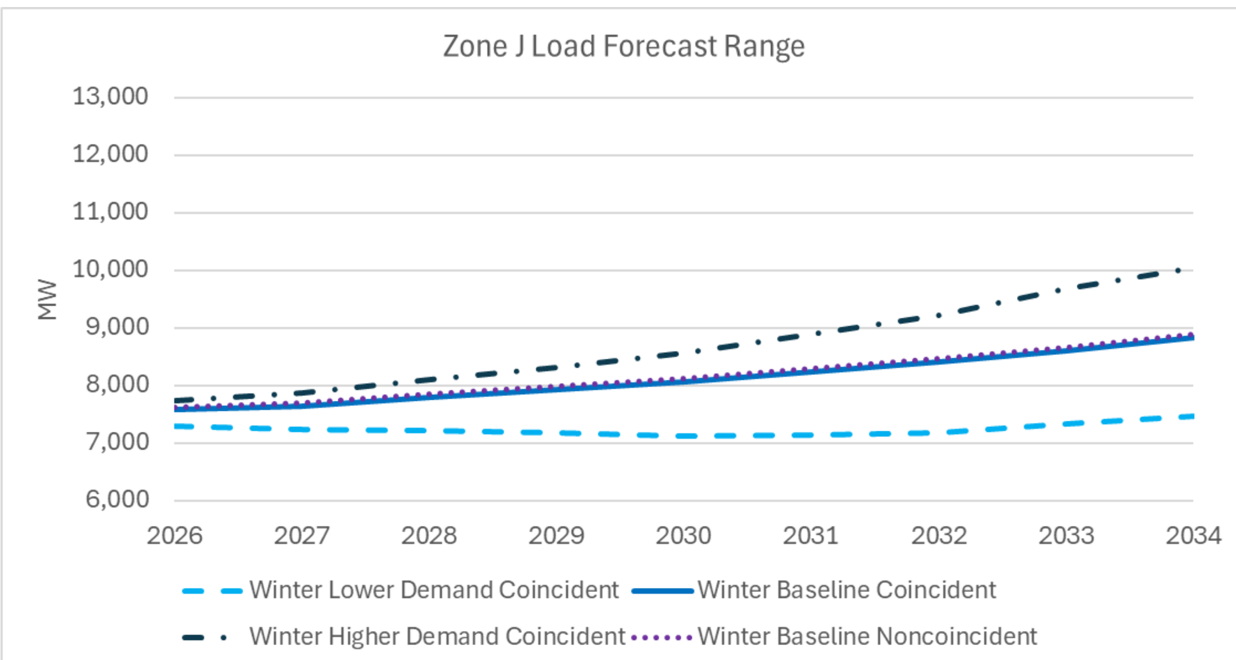


Figure 11: Zone J Summer Transmission Security Margin

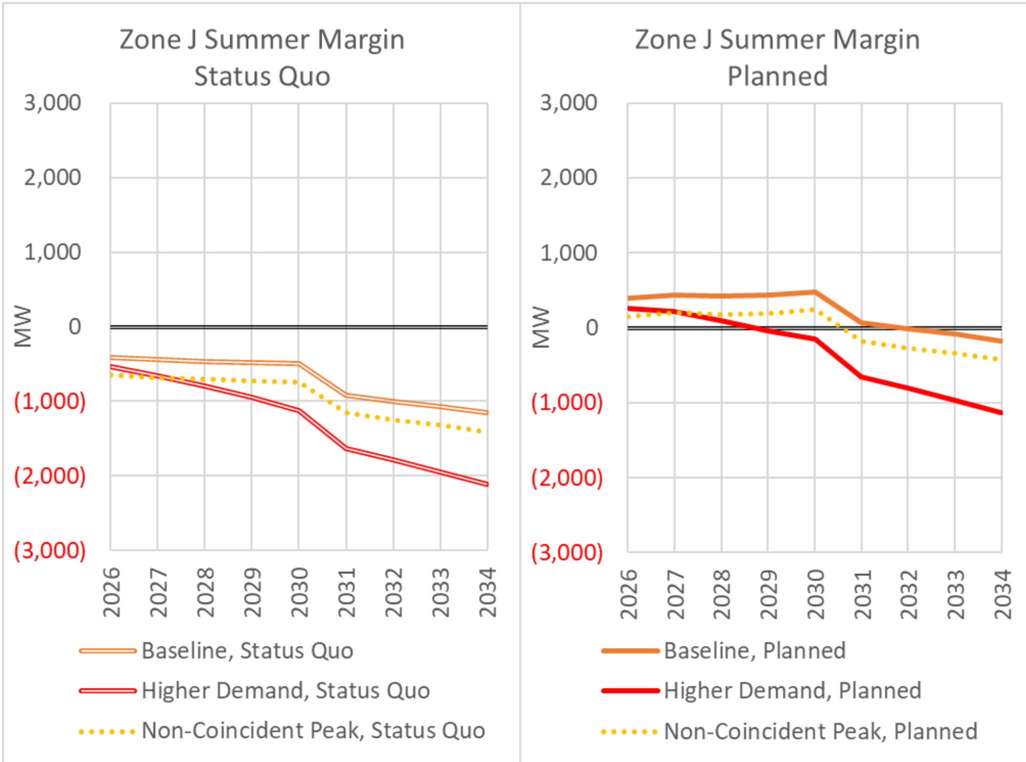


Figure 12: Zone J Winter Transmission Security Margin

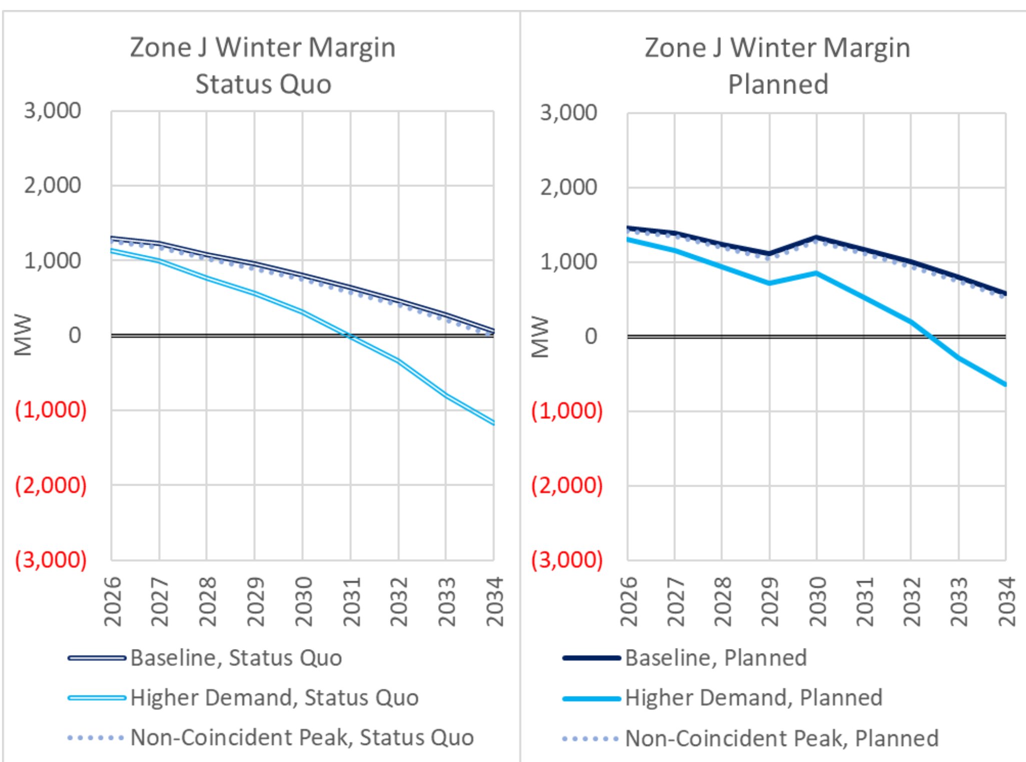
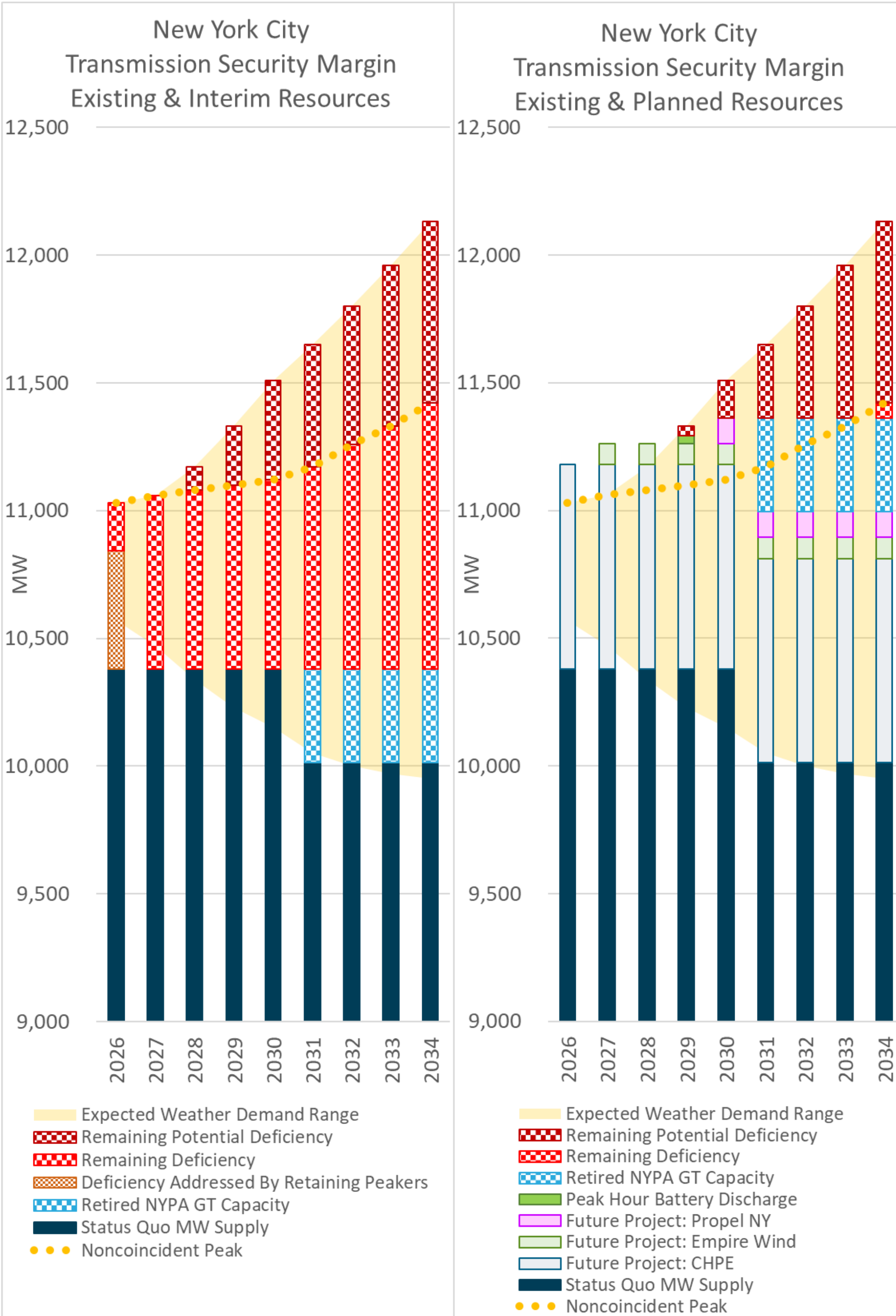


Figure 13: Factors Affecting New York City Transmission Security Margin at the Start of this STAR



In the 2025 Quarter 3 STAR, Con Edison's non-BPTF system analysis found no Generator Deactivation Reliability Needs following the retirement of the Gowanus and Narrows barges. In December 2025, the 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.[20] In December 2025, their 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 their 2025 Local Transmission Plan (LTP) at the March 20, 2026 ESPWG/TPAS meeting based on the findings under this proceeding.[21]

Long Island Transmission Security Margin

The 2025 Quarter 3 STAR found a Generator Deactivation Reliability Need on the BPTF in the Long Island locality starting in summer 2027 (hereinafter "Long Island BPTF Need") and a Generator Deactivation Reliability Need on the non-BPTF starting in summer 2026 and continuing throughout the entire study horizon in the Far-Rockaway Load Pocket (hereinafter "Long Island Non-BPTF Need"). The Long Island BPTF Need is primarily driven by the deactivation of Pinelawn (82 MW nameplate) and the Far Rockaway GTs (121 MW nameplate total), while the Long Island Non-BPTF Need is driven by the deactivation of the Far Rockaway GTs.

Following the publication of the 2025 Quarter 3 STAR, the NYISO received updates to key assumptions in Zone K, which reduced the Long Island BPTF Need. Notably, certain large load projects in Zone K, which were included in the expected weather forecast in the Gold Book, have been removed from the assumptions based on updates received from LIPA.[22]

The Generator Deactivation Reliability Needs in Long Island are shown in the tables below.

[20] 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).

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

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

Long Island BPTF Need

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

Long Island Non-BPTF Need (Far Rockaway Load Pocket)

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

Once Sunrise Wind (880 MW nameplate, planned in-service date July 2027) is delivering power at the planned power capability, the Long Island BPTF margins improve in summer 2028, followed by dramatic improvement in 2030 with the planned energization of the Propel NY project in May 2030 such that the margins remain positive throughout the remainder of the planning horizon. However, the Long Island BPTF Need would still be observed in summer 2027. The planned projects had negligible impact on the Long Island non-BPTF Need.

Figure 15 and Figure 16 depict the reliability margins for Long Island without any planned projects ("status-quo") and as planned. The Long Island summer peak margin is also shown in Figure 17, which illustrates the reliability impact of the status quo as well as future planned generation and transmission projects that have met the Reliability Planning Process inclusion rules.

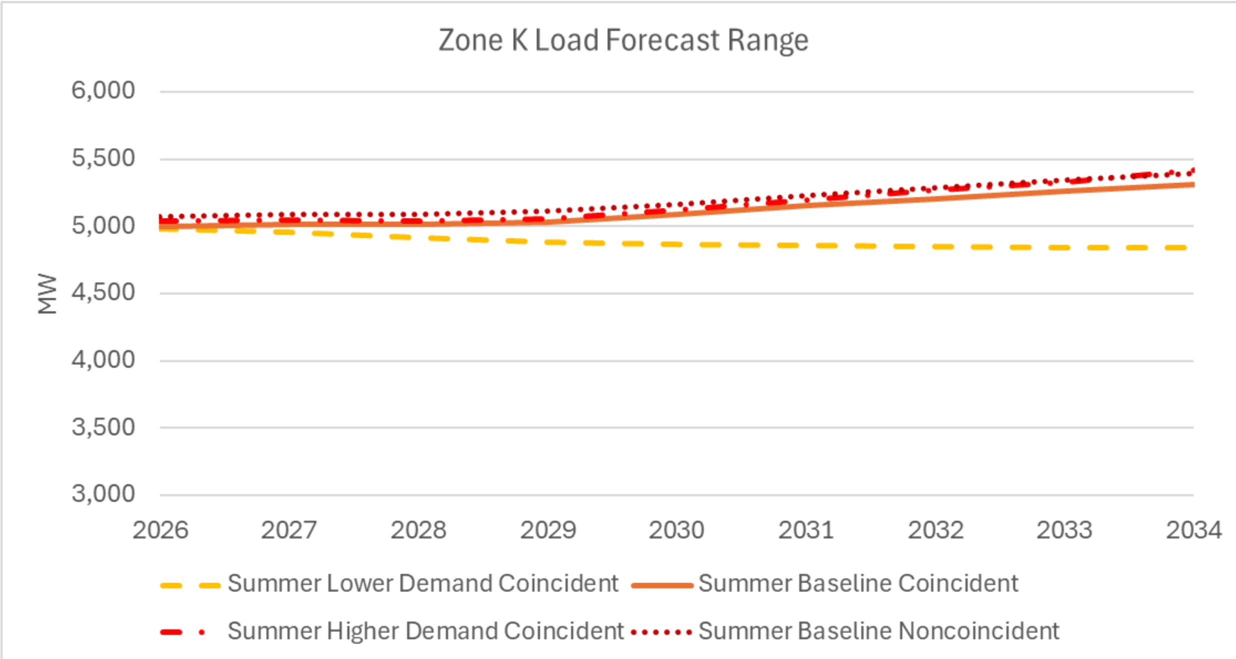
These deficiencies are driven by the proposed deactivations of the Pinelawn and Far Rockaway generators in combination with other factors such as: the range in the demand forecasts based on expected weather, expected generator availability, transmission limitations, and risks associated with the availability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

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

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

As discussed in the April 15, 2026 Short-Term Reliability Process Report, additional projects have been identified and their impact is discussed later in this STAR in the section "solutions to previously identified short-term reliability needs." Until sufficient system plans within Long Island are completed and demonstrate their planned power capabilities to address the identified reliability needs, the previously identified BPTF and non-BPTF deficiencies would persist. While these planned projects are advancing in their development, the completion is subject to inherent risks commonly observed among large infrastructure projects that may impact timely completion and energization. Key challenges include permitting, material availability, construction complexities, and other unexpected factors.

Figure 14: Zone K Load Forecast Uncertainty



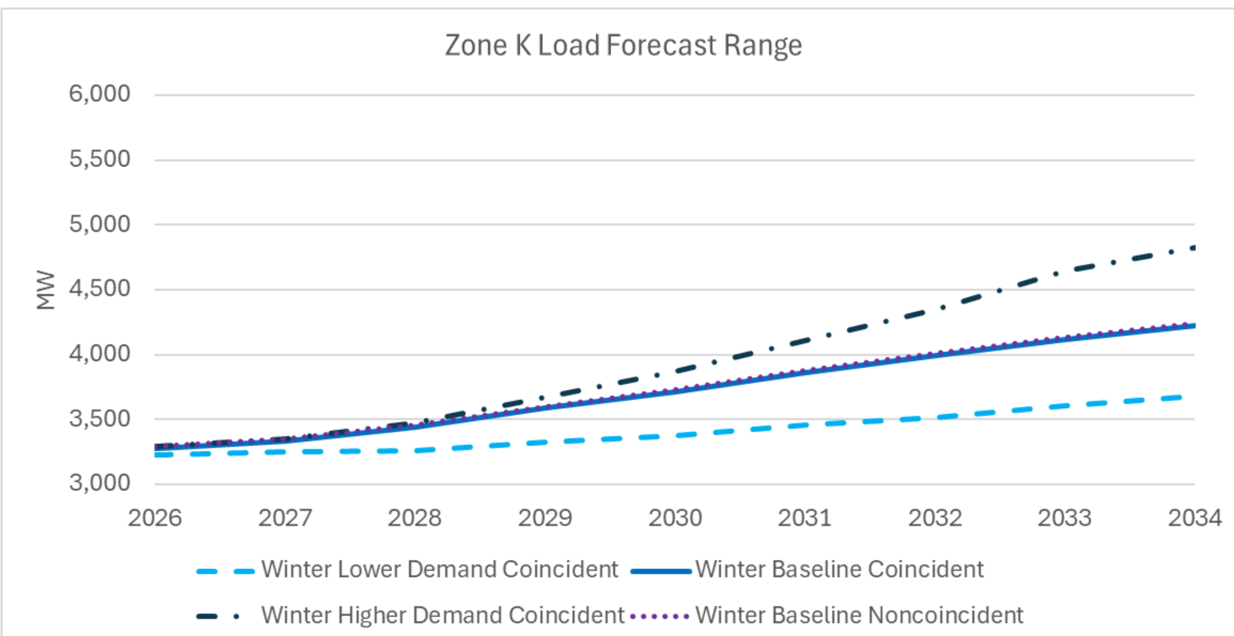


Figure 15: Zone K Summer Transmission Security Margin

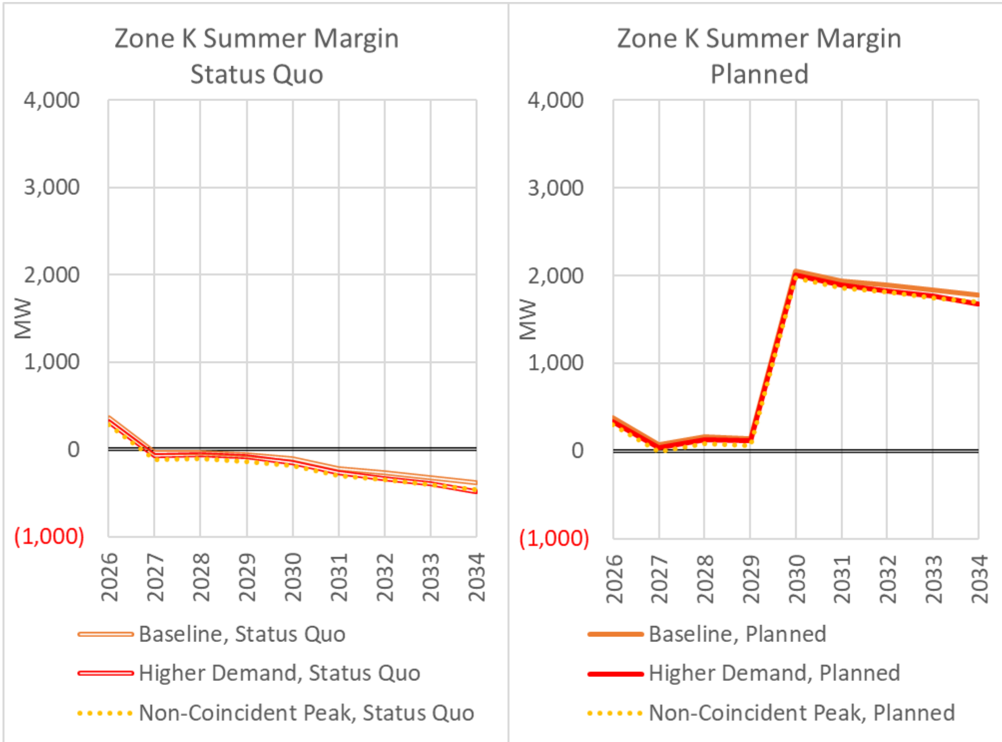


Figure 16: Zone K Winter Transmission Security Margin

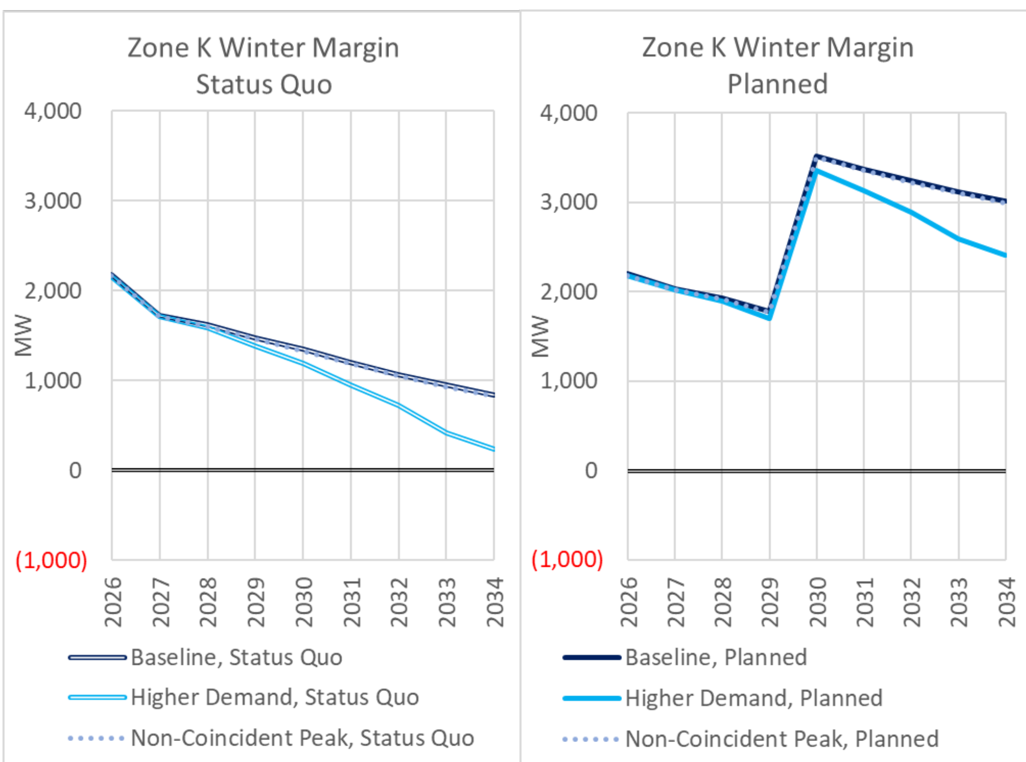
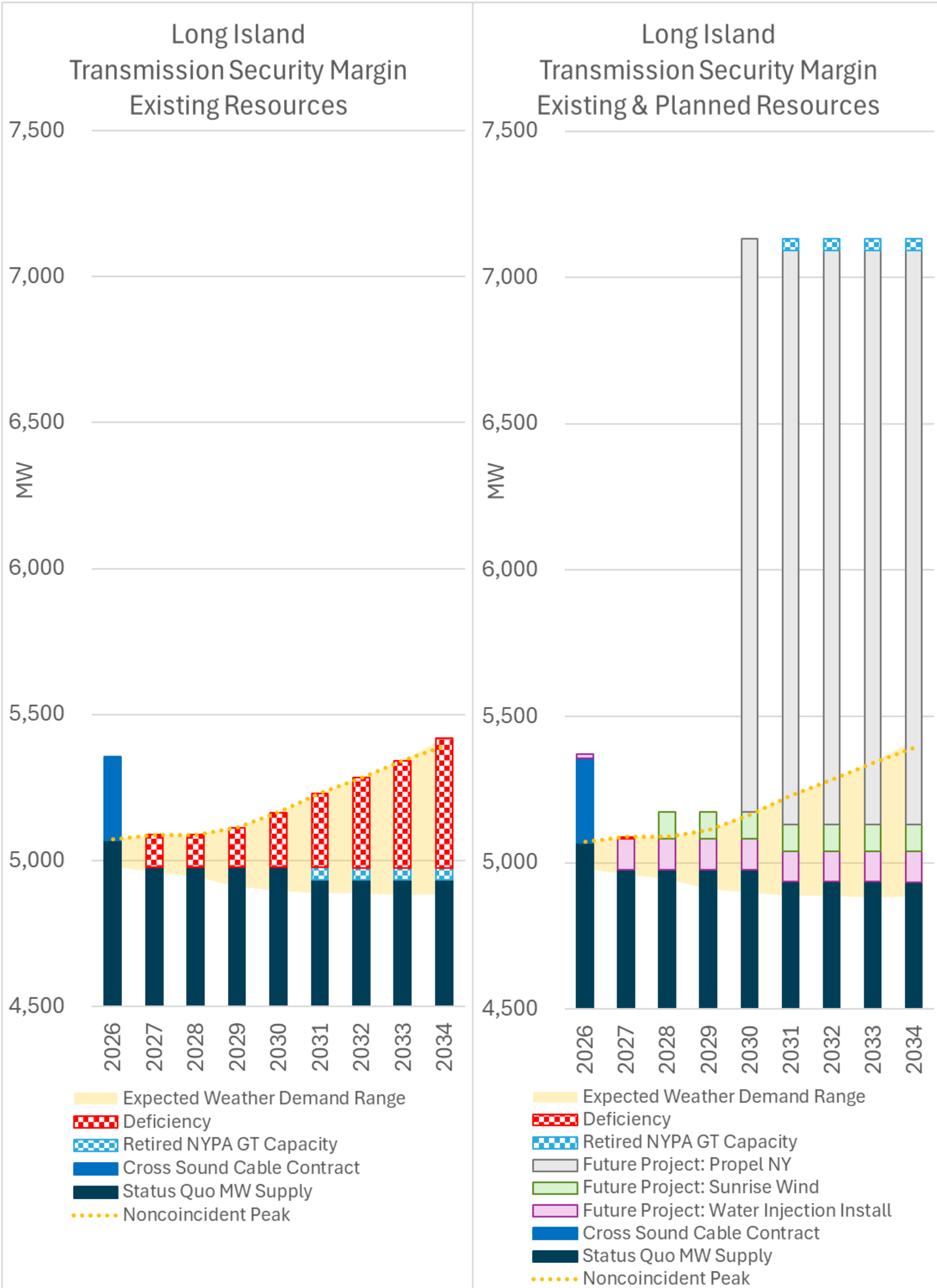


Figure 17: Factors Affecting Long Island Transmission Security Margin at the Start of this STAR



Lower Hudson Valley Transmission Security Margin

Consistent with the findings of the 2025 Quarter 3 and Quarter 4 STARs, this STAR continues to find that the Lower Hudson Valley locality would be deficient without the completion and energization of the future planned projects in New York City and Long Island without the selected solutions identified for these localities. The observed Lower Hudson Valley deficiency observed in prior STARs was primarily an exacerbation of the New York City BPTF Generator Deactivation Reliability Need and was also impacted by the BPTF Generator Deactivation Reliability Need identified in Zone K. The 2024 Quarter 4 STAR observed a Lower Hudson Valley deficiency of 195 MW over 3 hours (729 MWh) in summer 2030. Accordingly, the NYISO did not separately seek solutions to address the deficiency for the Lower Hudson Valley beyond the solutions for the identified needs in Zones J and K required in the November 10, 2025 solution solicitation.

The following table provides the magnitude and duration of the BPTF deficiency observed in this STAR throughout the five-year study period based on the study assumptions at the start of this study ("Lower Hudson Valley BPTF Need").

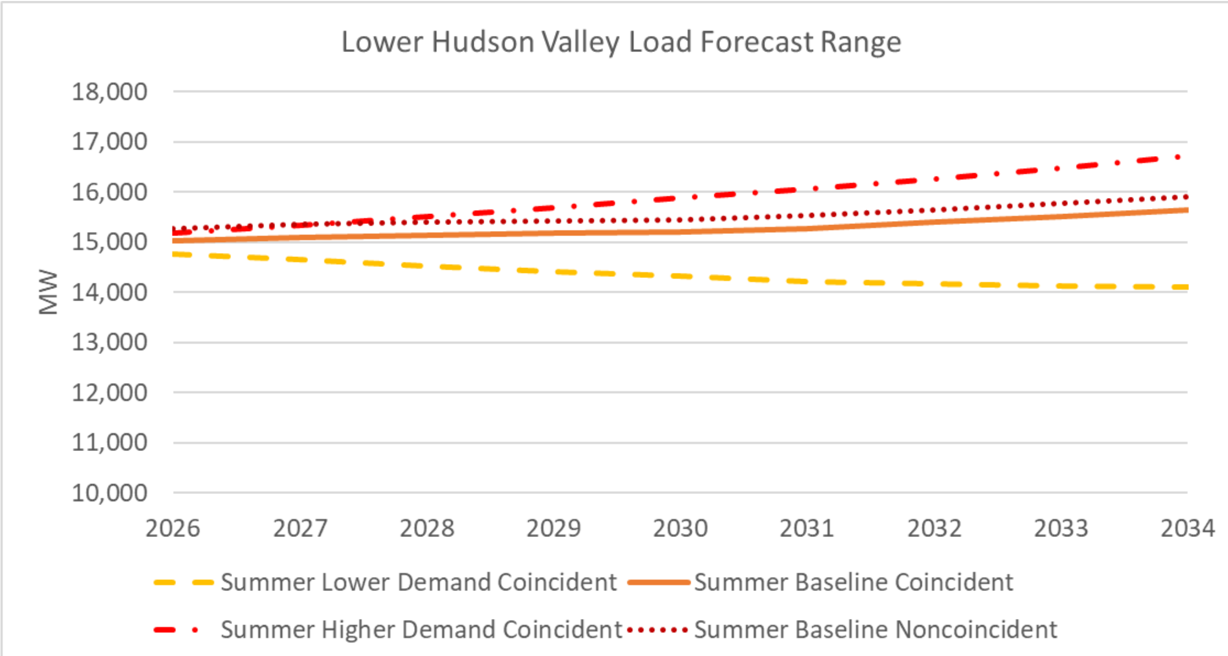
Lower Hudson Valley BPTF Need:

Summer Peak	**2026**	**2027**	**2028**	**2029**	**2030**
MW Deficiency	None	17-27	69-184	121-383	202-639
Duration (hours)	None	1	3	3-4	3-6
MWh	None	17-27	396-756	521-1,446	718-2,663

The exacerbation of the bulk system deficiency observed in this STAR is primarily driven by the deactivation of Danskammer 1-4 in combination with demand forecasts based on expected weather, expected generator availability, transmission limitations, and risks associated with the availability of key future planned projects. The observed deficiencies in this locality are also driven in part by the RECO demand, whose MW supply from PJM, must flow through across Lower Hudson Valley transmission in New York. The impact of solutions identified in the Short-Term Reliability Process Report are discussed later in this report.

The range in the demand forecast driven by uncertainties in key assumptions, such as population and economic growth, energy efficiency, the installation of behind-the-meter renewable energy resources, and electric vehicle adoption and charging patterns as described in the 2025 Gold Book. The forecasted summer peak demand in Lower Hudson Valley has a range of 517 MW in 2026 growing to 1,566 MW in 2030, primarily driven by assumptions in electrification of transportation and buildings. Details of the different load forecasts used in this STAR are shown below in Figure 18. The assumed available supply has also been adjusted to account for expected reductions of 110 MW in generators' dependable maximum net capability (DMNC) in zone J and 175 MW reduction in capacity sales from PJM. Figure 19 and Figure 20 depict the reliability margins for the Lower Hudson Valley without any planned projects ("status quo") and as planned. Figure 21 shows the Lower Hudson Valley summer peak margin under status quo as well as future planned generation and transmission projects that have met the Reliability Planning Process inclusion rules for this STAR.

Figure 18: Lower Hudson Valley Load Forecast



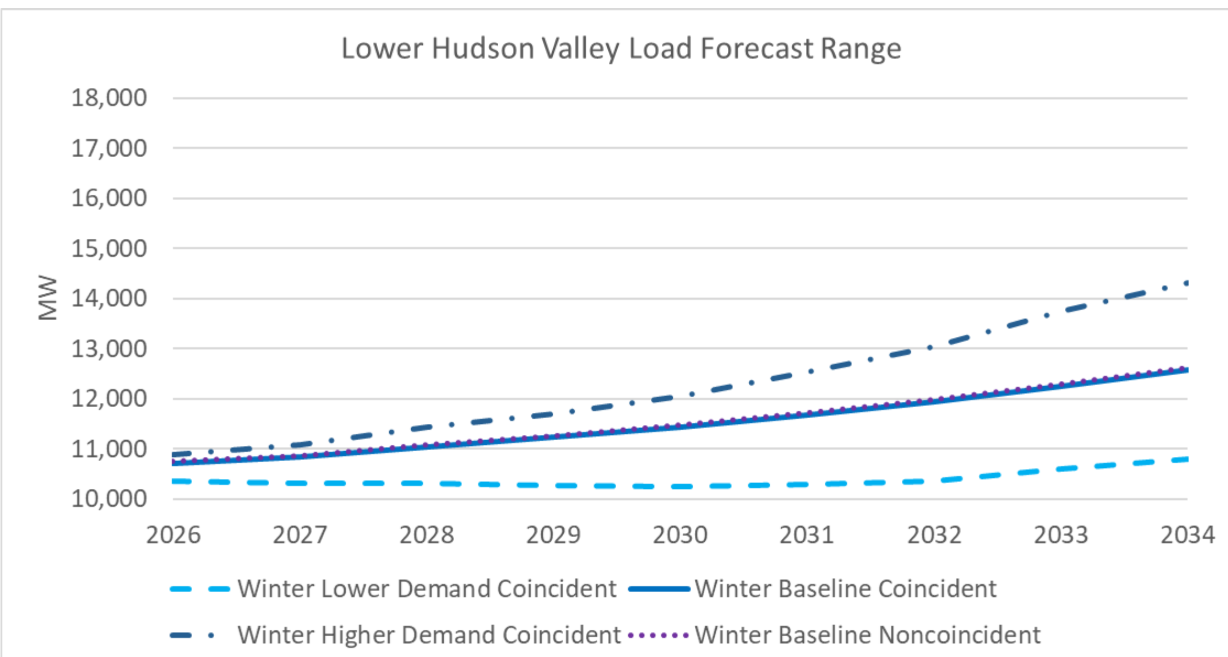


Figure 19: Lower Hudson Valley Summer Transmission Security Margin

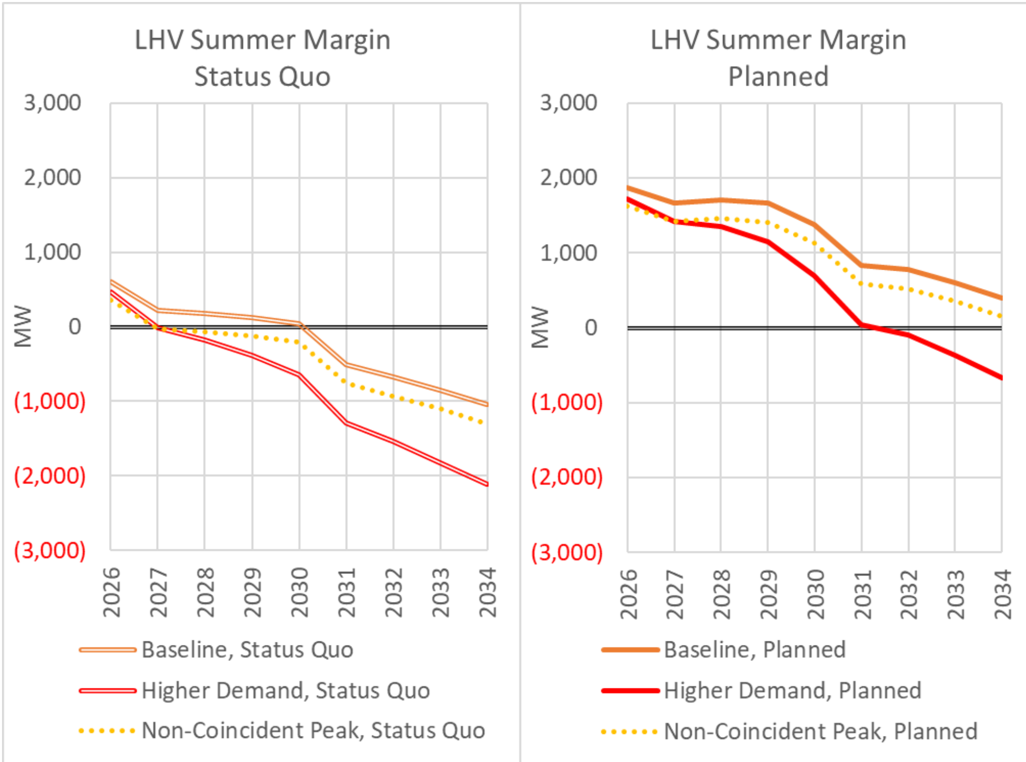


Figure 20: Lower Hudson Valley Winter Transmission Security Margin

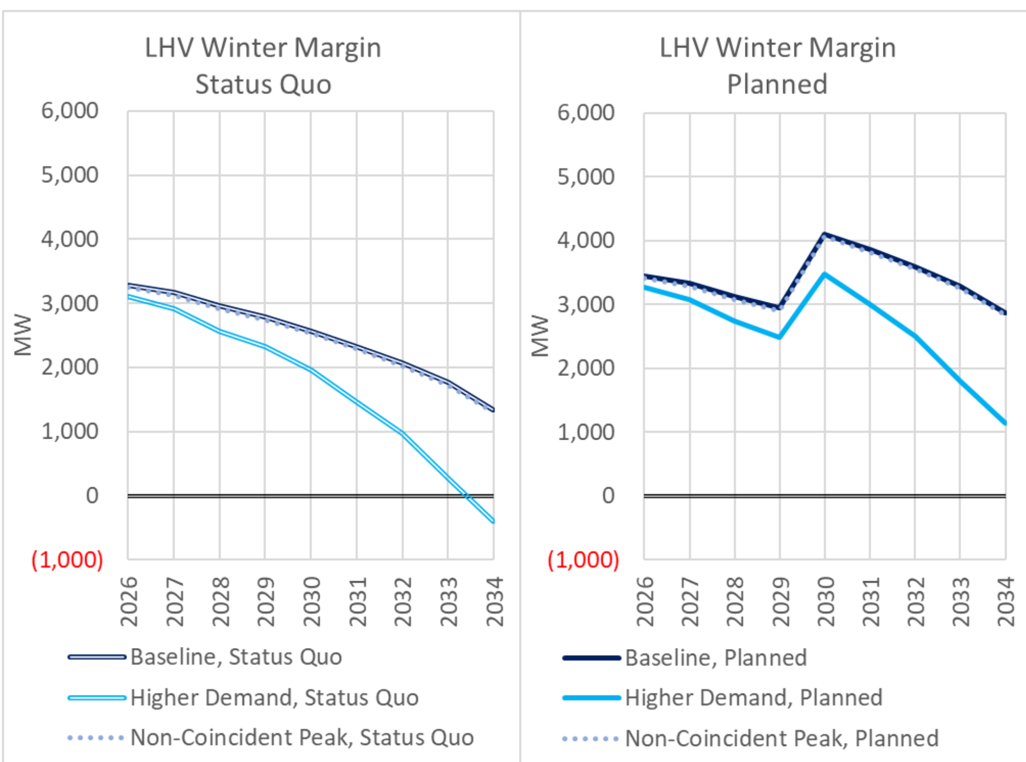
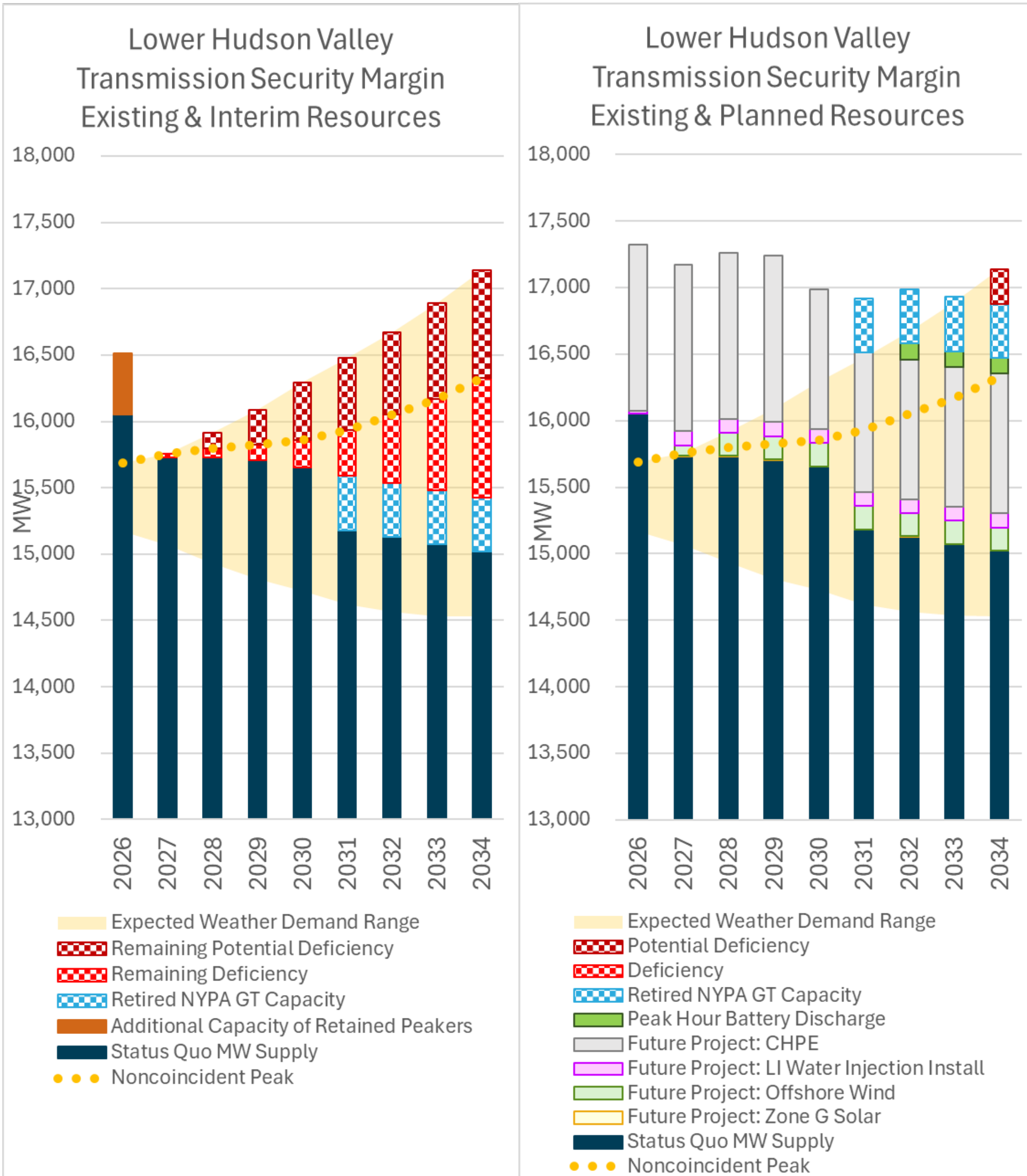


Figure 21: Factors Affecting Lower Hudson Valley Transmission Security Margin at the Start of this STAR



Reliability Margin Projections

Reliability conditions over the planning horizon reflect a growing set of structural and operational risks. The system is becoming more sensitive to changes in generator availability, demand growth, and project timing as aging resources remain in service and replacement capacity lags. Projected reliability margins indicate a grid that is becoming less operable over time. Even where reliability criteria are met, declining margins increase reliance on emergency tools and operational interventions, particularly during periods of extreme weather or reduced resource availability. The projections demonstrate that small deviations from planned assumptions, such as delays in projects, higher-than-expected demand, or generator outages, could materially affect reliability outcomes in both the near and longer term.

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 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 following section provides insights into reliability margins over the next ten years, taking into consideration the revised demand forecasts[23] to be published in the 2026 Gold Book coupled with the recognition of aging generation statistical risks. The same information will be the basis for key findings in this year's RNA, for which full preliminary results will be available in July, with the final report to be published by the end of 2026. With the revised 2026 Gold Book forecasts, in general the higher demand forecast has reduced but the baseline forecast has increased for the New York City, Long Island, and Lower Hudson Valley localities.

Through the quarterly STAR studies, the NYISO will continuously evaluate the reliability of the system as changes occur and will carefully monitor the progress of the planned permanent projects toward completion. The 2026 RNA will evaluate the reliability of the New York bulk electric grid over the ten-year planning horizon, with a focus on 2030-2036, considering updated forecasts of grid demand according to the 2026 Gold Book, planned transmission upgrades, and projected changes to the generation fleet. As presented in the recent 2025-2034 CRP, the NYISO proposes to

[23] Draft 2026 Gold Book forecasts were provided to Stakeholders at the April 7, 2026 TPAS/ESPWG/LFTF (here)

incorporate aging generation risk to better capture the likelihood of future resource unavailability and identify emerging reliability needs beyond the short-term horizon.

Statewide Adequacy

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 a 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. Statewide system margin is a measure of the amount of generation and net imports available to supply firm load over the bulk power transmission system within applicable normal ratings and limits while maintaining 10-minute operating reserves. A negative statewide system margin, on its own, is not a criteria violation, but it is a leading indicator of the system's inability to securely serve demand under normal operations.

As shown in Figure 22 and Figure 23, when considering the 2026 Gold Book demand forecasts, the statewide system margin would be deficient starting in summer 2027 until future planned projects have demonstrated their capabilities. However, even with future planned projects in-service on schedule, the risks to reliability would remain as the statewide system margin would again become deficient as early as 2030, and worsen rapidly thereafter as demand grows and old fossil generators are likely to retire. As shown in Figure 24 and Figure 25, similar issues are observed under winter peak. While the peak demand is lower in winter, so is the available supply due to fuel and import constraints.

In the near term, these declining margins indicate a less operable system. This is concerning because it means that NYISO operators will have to utilize the tools in their toolbox more often, such as emergency operating procedures (EOPs), since the "just right" system condition in planning is often more optimistic than typical conditions experienced by operators. The EOPs consist of load control and capacity resource supplements that can be implemented before load must be disconnected due to capacity shortages. Load control measures include implementation of demand response programs, public appeals to reduce demand, and voltage reduction. Capacity resource supplements could include emergency purchases and cutting operating reserves. The 2025-2034 CRP further describes how the utilization of emergency actions is expected to triple over the next ten years without additional dispatchable generation.

Figure 22: Factors Affecting Statewide System Margin (Summer Peak)

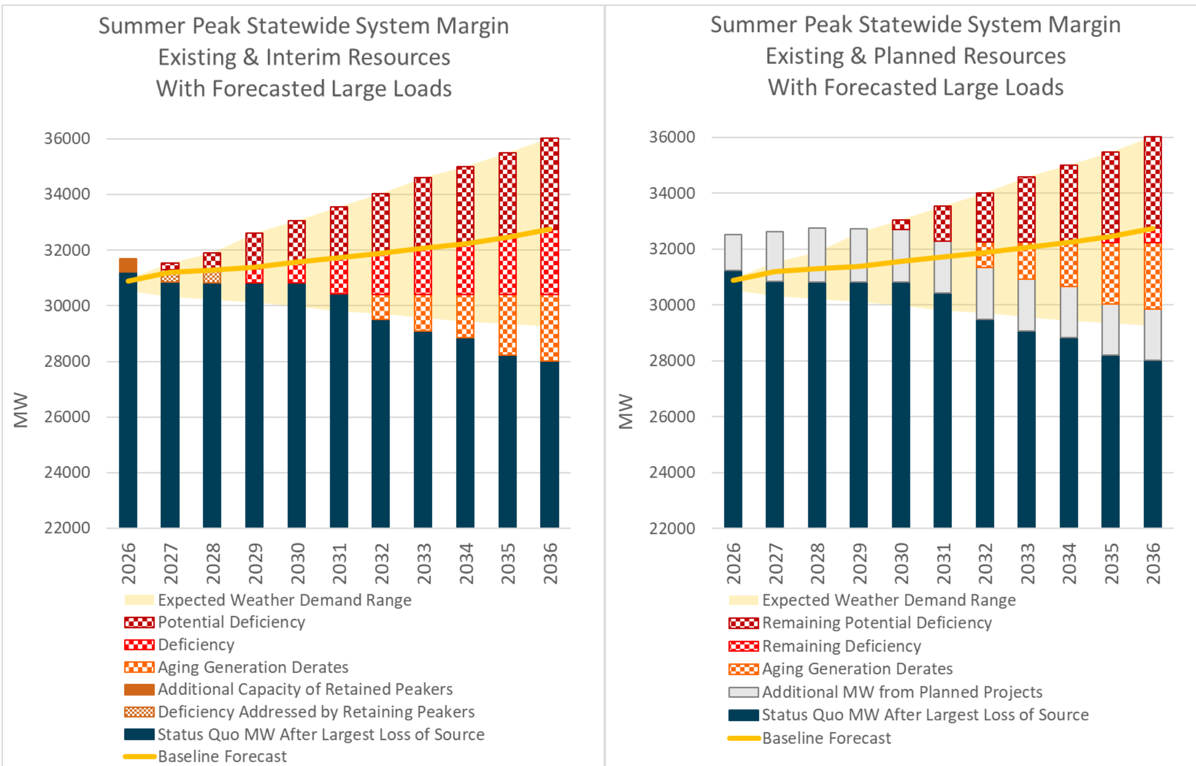


Figure 23: Statewide System Margin (Summer Peak)

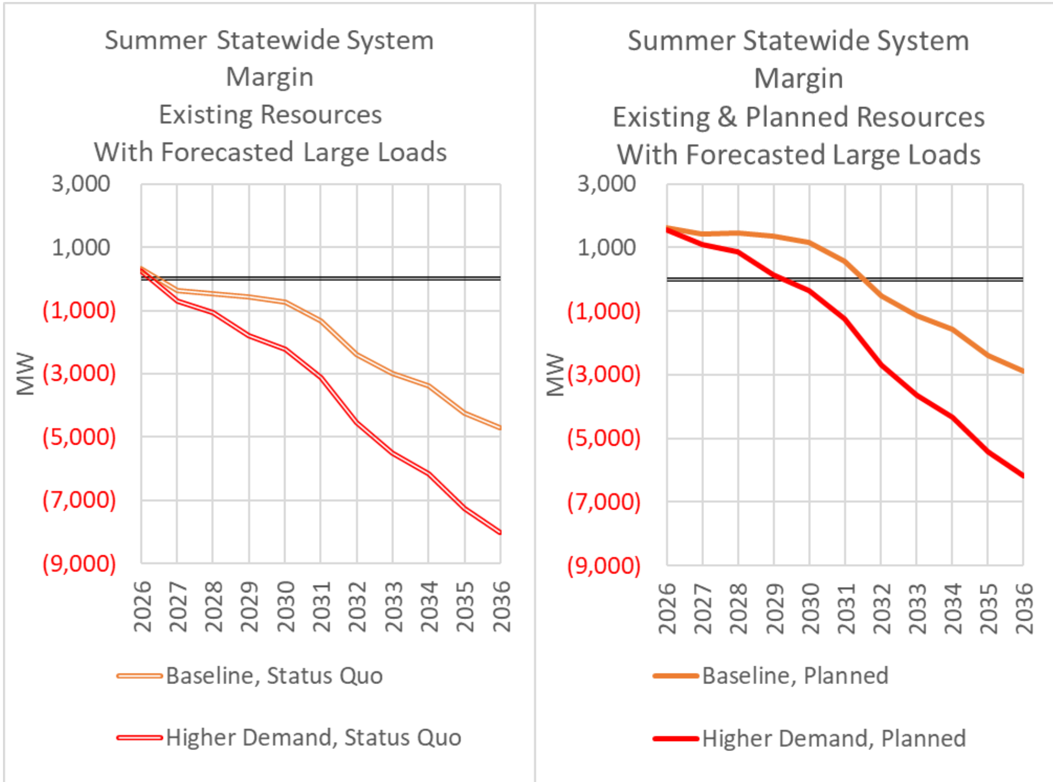


Figure 24: Factors Affecting Statewide System Margin (Winter Peak)

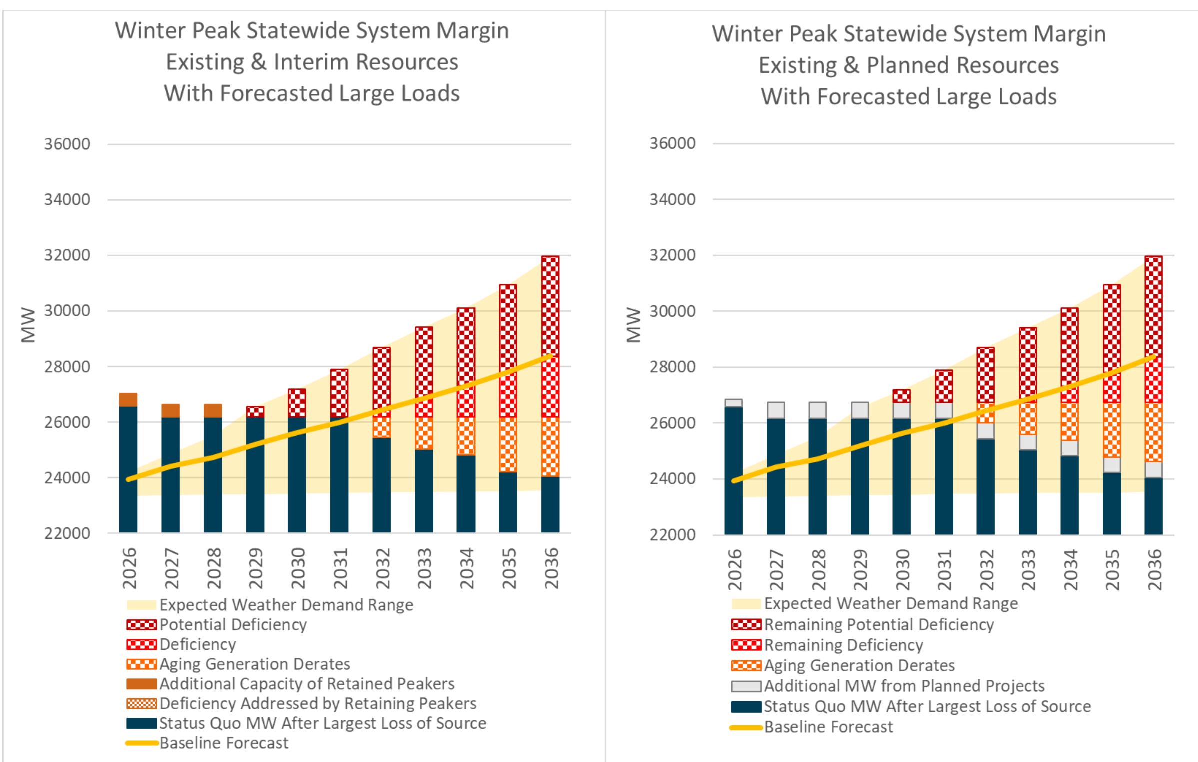
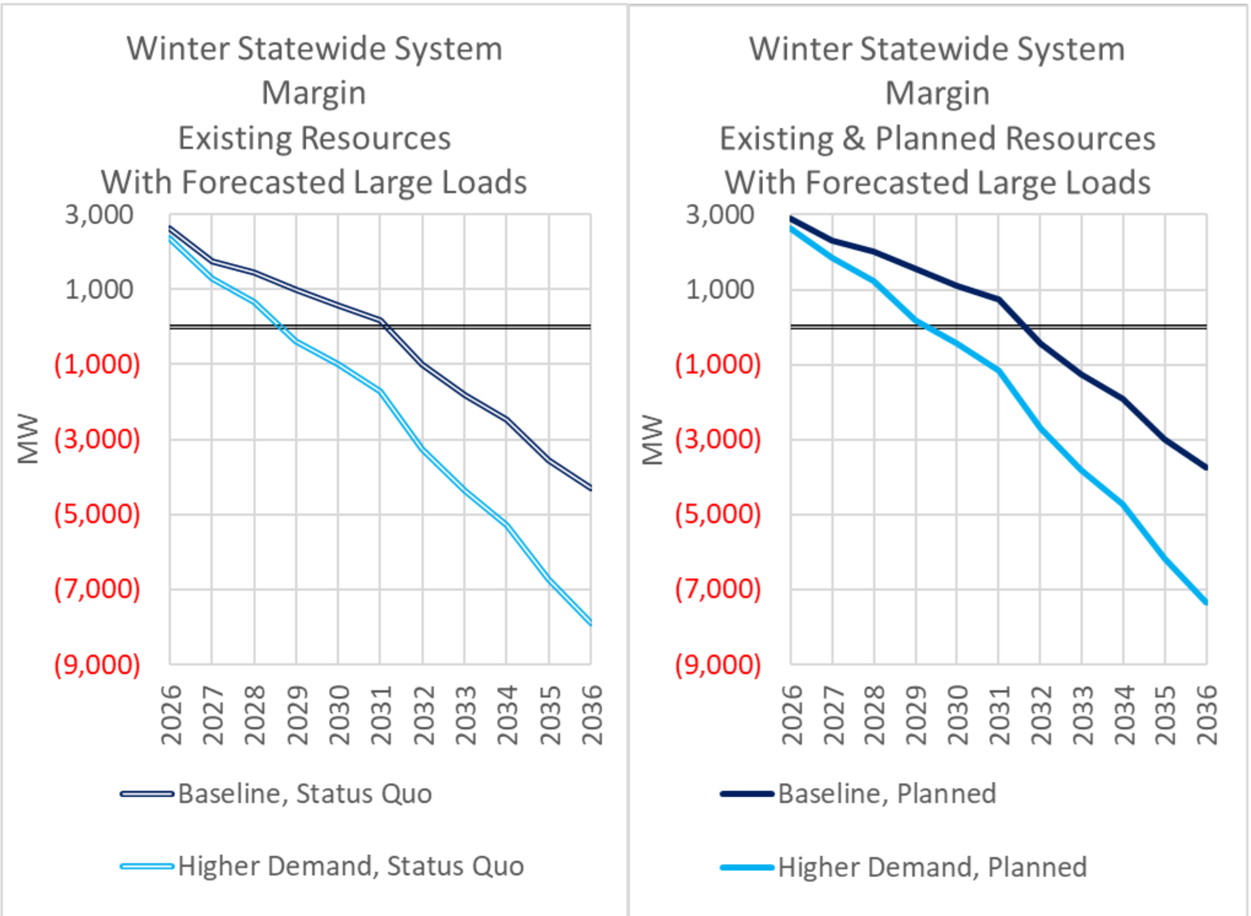


Figure 25: Statewide System Margin (Winter Peak)



In the 2026 Quarter 1 STAR assessment, the NYISO found that the planned system through the five-year study period meets the resource adequacy criterion. However, when considering the potential for delays in planned projects ("status quo"), a LOLE violation (*i.e.,* above 0.1 event-days/year) would occur in 2030. The deficiency without planned projects or retained generation is estimated to be 525 MW.

Locality Transmission Security Margins

With the revised 2026 Gold Book forecasts, in general the higher demand forecast has reduced but the baseline forecast has increased for the New York City, Long Island, and Lower Hudson Valley localities. These localities are also home to the oldest generation in New York State, resulting in accelerating risks in the long term as demand increases and supply projected to rapidly decrease.

Within New York City, the planned unavailability of the NYPA Small Plants (517 MW) by December 31, 2030 would result in a deficiency in 2031. When coupled with the risk of aging generation retirements, New York City would be substantially deficient of reliable power, with projected deficiencies growing to more than 2,000 MW by 2036 as shown in Figure 26 and Figure 27.

Should the proposed Gowanus site repowering with hydrogen capable turbines (819 MW nameplate) be available in this timeframe, the deficiency would be significantly reduced. It is notable that these types of solutions provide the reliability attributes of dispatchable resources discussed in the 2025-2034 CRP.[24] As these types of solutions would be critical to achieving reliability beyond the short-term horizon, the NYISO encourages entities to work together to establish the pathway for these types of resources to interconnect and supply power to the grid. The NYISO also notes that the conceptual proposed transmission solution put forward by Con Edison would also help to improve reliability in the longer-term horizon (2035 and beyond) by increasing the transfer capability into this locality by about 700-800 MW. However, additional transmission capacity into a locality only provides reliability benefit when coupled with sufficient statewide supply to transfer into that locality.

[24] *See* appendix G of the 2025-2034 Comprehensive Reliability Plan found on the NYISO website (here)

Figure 26: Factors Affecting New York City Transmission Security Margin (2026 RNA Horizon)

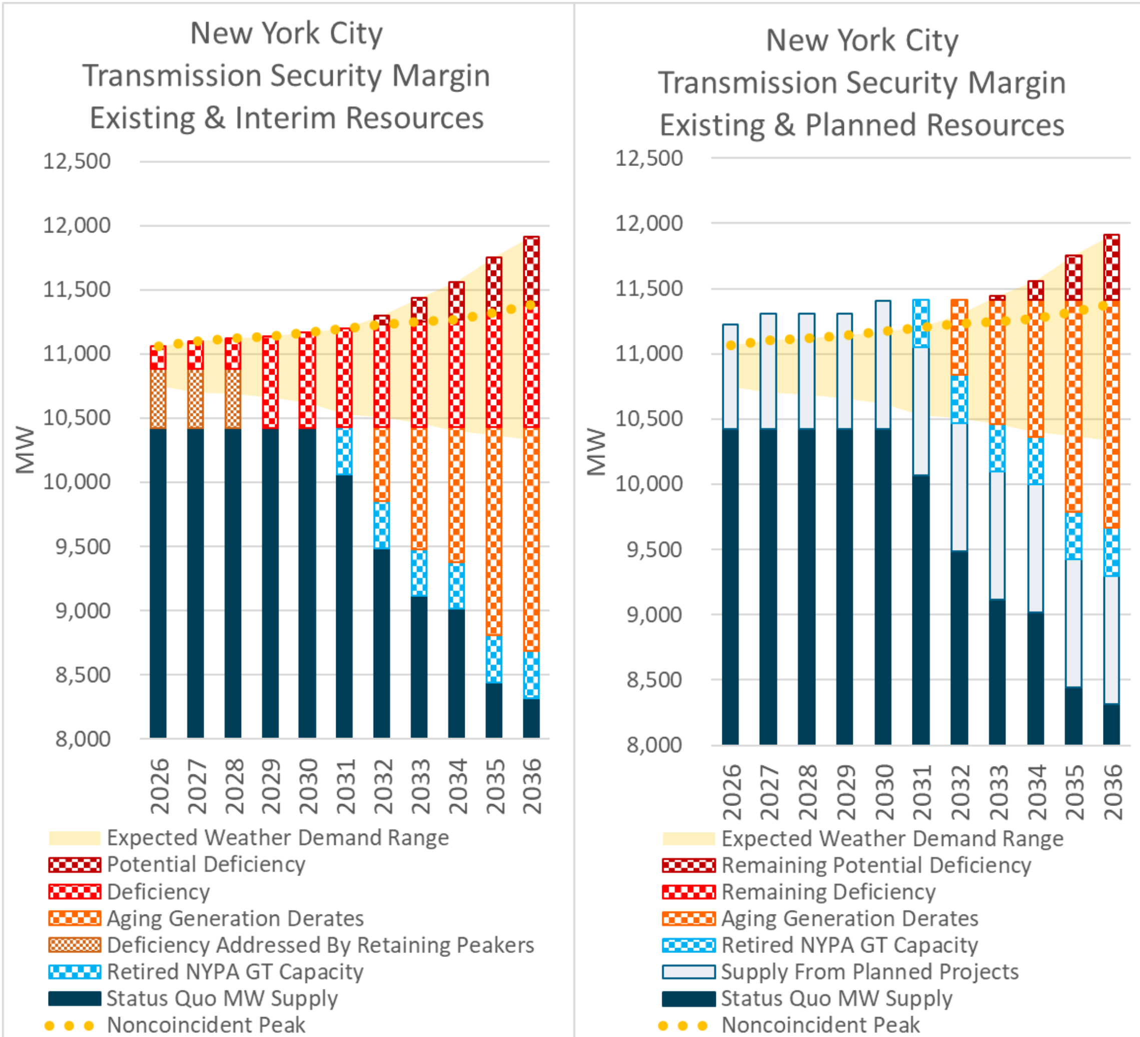
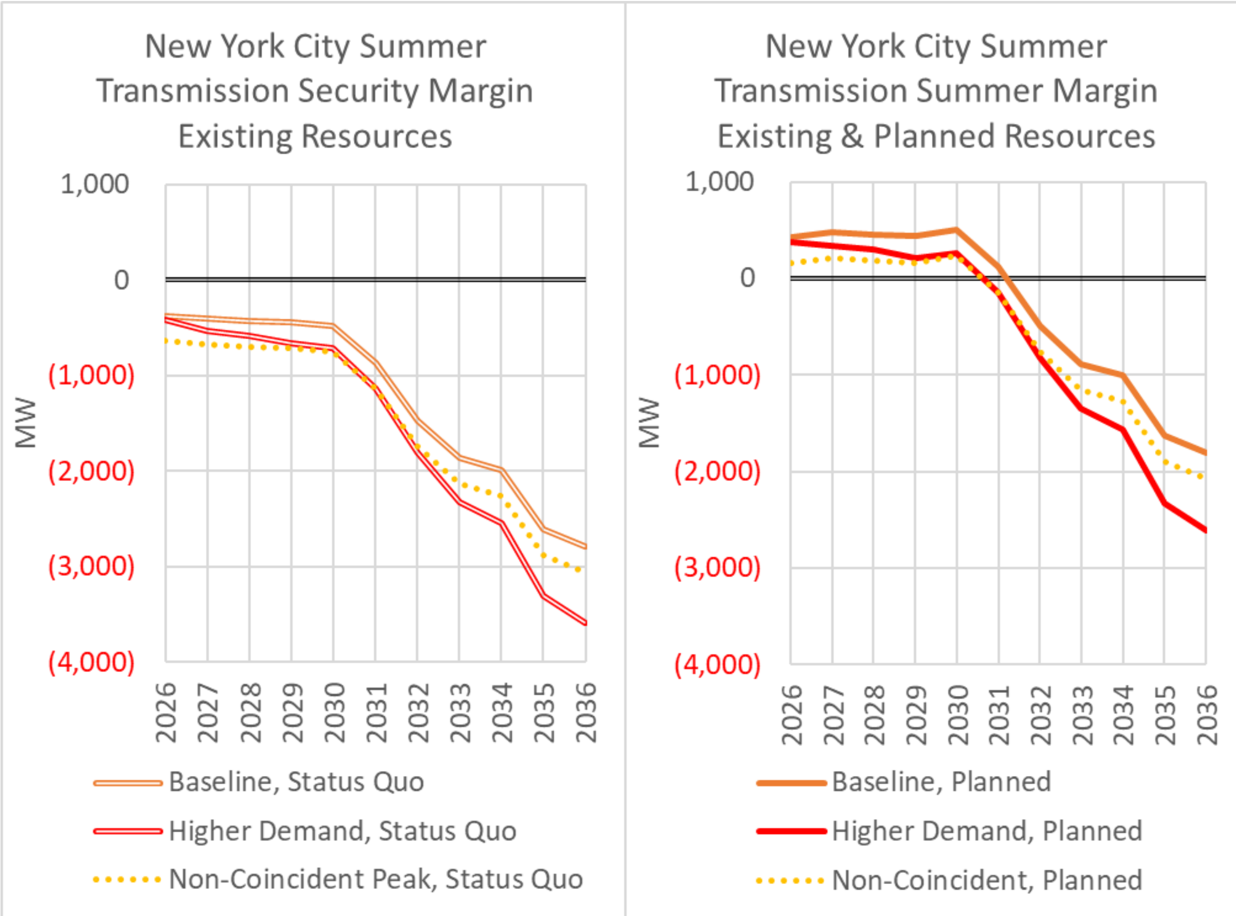


Figure 27: New York City Transmission Security Margin (2026 RNA Horizon)



As with New York City, Long Island must rely heavily on planned projects to meet reliability in the future. The revised demand forecasts continue to indicate a near-term need for generation solutions and a reliance on the completion of the Propel NY transmission project. Considering the risk of aging generation in the long term, Long Island would be deficient starting in 2031 without the Propel NY transmission project. While this project provides sufficient transmission into the locality over the long term, as shown in Figure 28 and Figure 29, sufficient statewide supply or imports will need to be available to help meet the demand. PSEG-LI/LIPA has issued a request for proposals to procure up to 345 MW of capacity from one or more generating facilities located in the ISO-NE control area for several capability years up to May 1, 2031.[25]

[25] On October 24, 2025, PSEG Long Island, as agent of and acting on behalf of LIPA, issued a request for proposals, the 2025 ISO-NE Capacity Request for Proposals, to procure up to 345 MW of Capacity from one or more generating facilities located in the New England Control Area. Details of this RFP are found on the PSEG-LI website (here).

Figure 28: Factors Affecting Long Island Transmission Security Margin (2026 RNA Horizon)

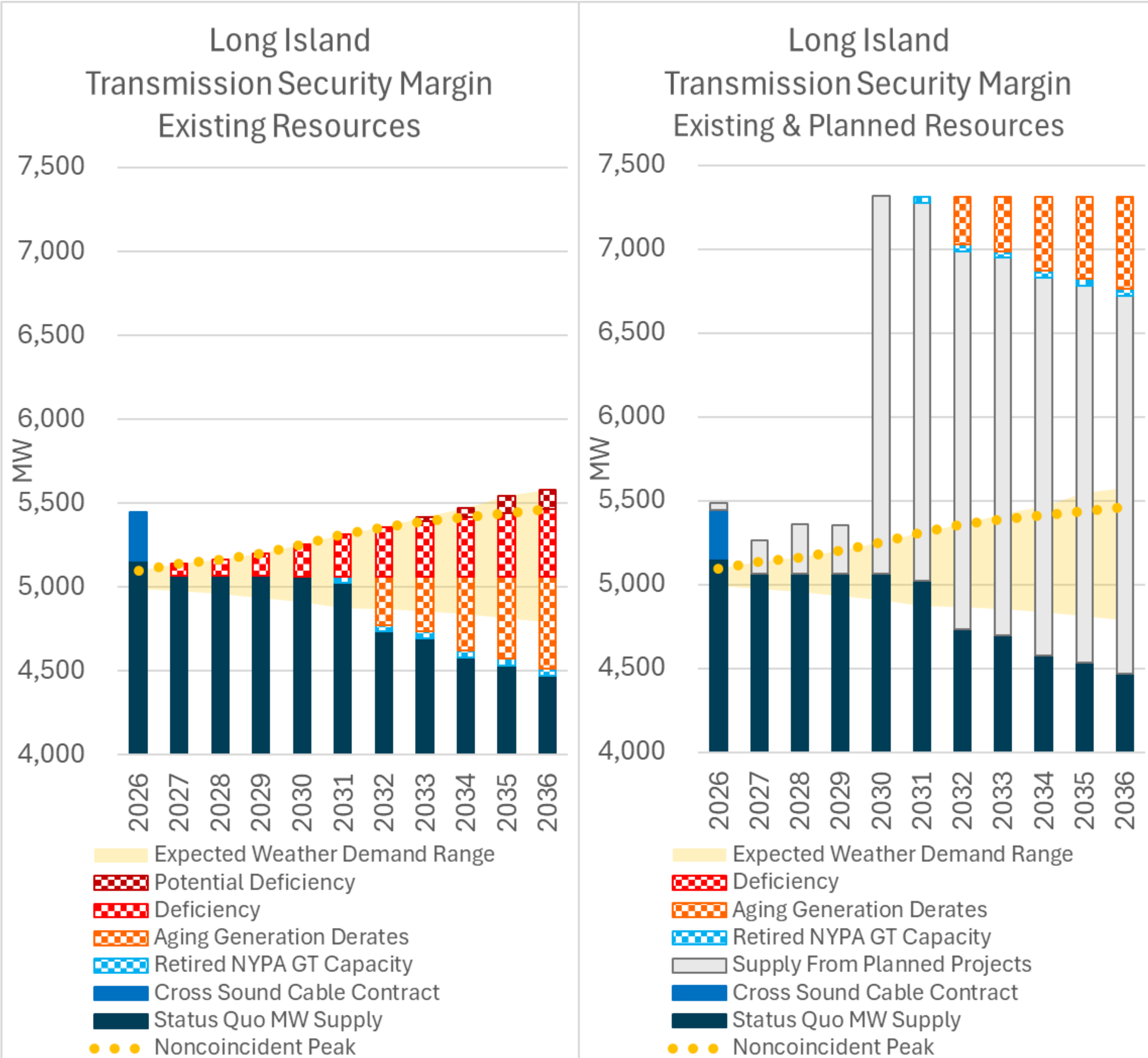
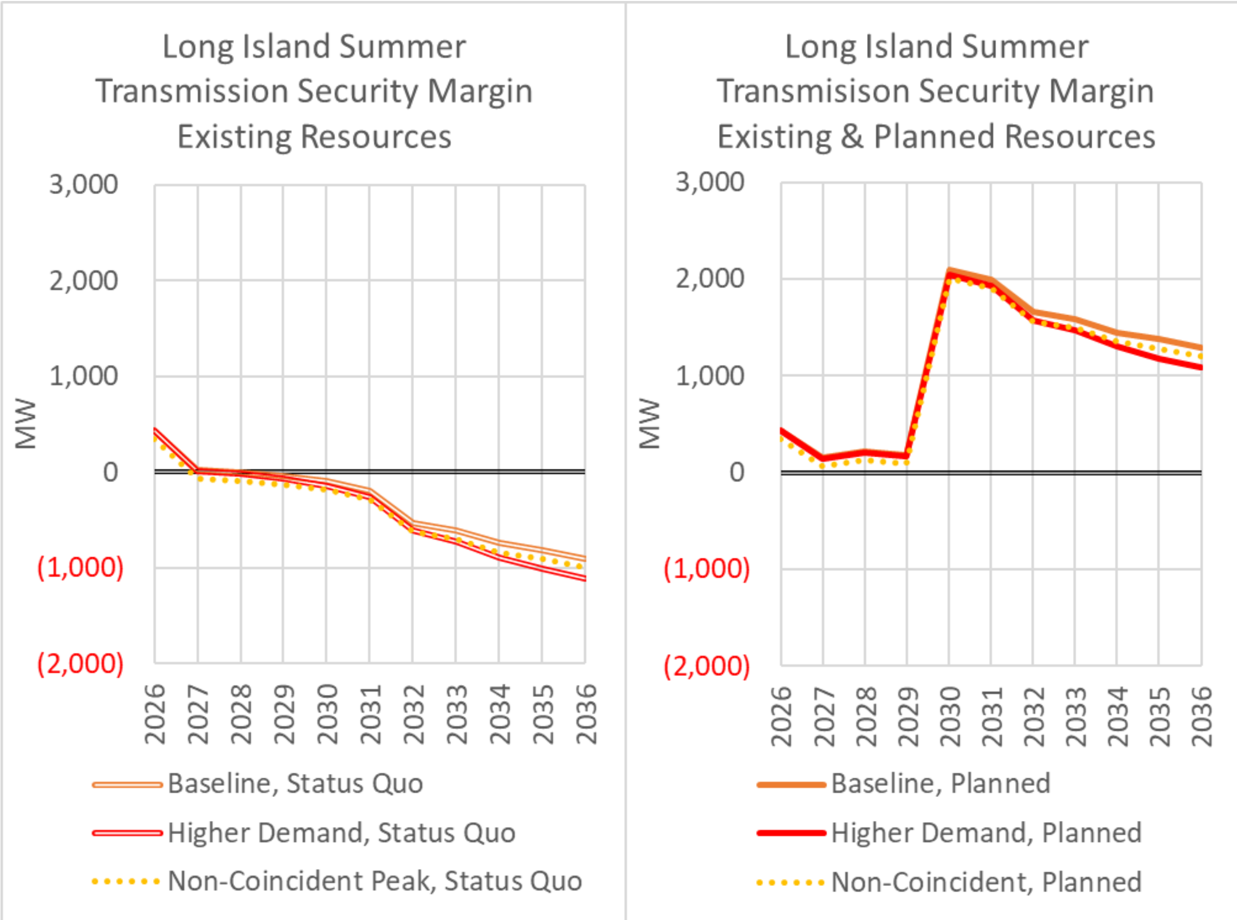


Figure 29: Long Island Transmission Security Margin (2026 RNA Horizon)



With increased demand forecasts for the Lower Hudson Valley locality (which includes New York City), the near-term reliability needs remain until planned projects enter service. Similar to New York City, the combined effect from the unavailability of the NYPA Small Plants and aging generation risk significantly reduces the available supply in the Lower Hudson Valley over the ten-year planning horizon. As seen in Figure 30 and Figure 31, deficiencies would start in 2032 growing to more than 2,000 MW by 2036, even after accounting for planned projects.

Figure 30: Factors Affecting Lower Hudson Valley Transmission Security Margin (2026 RNA Horizon)

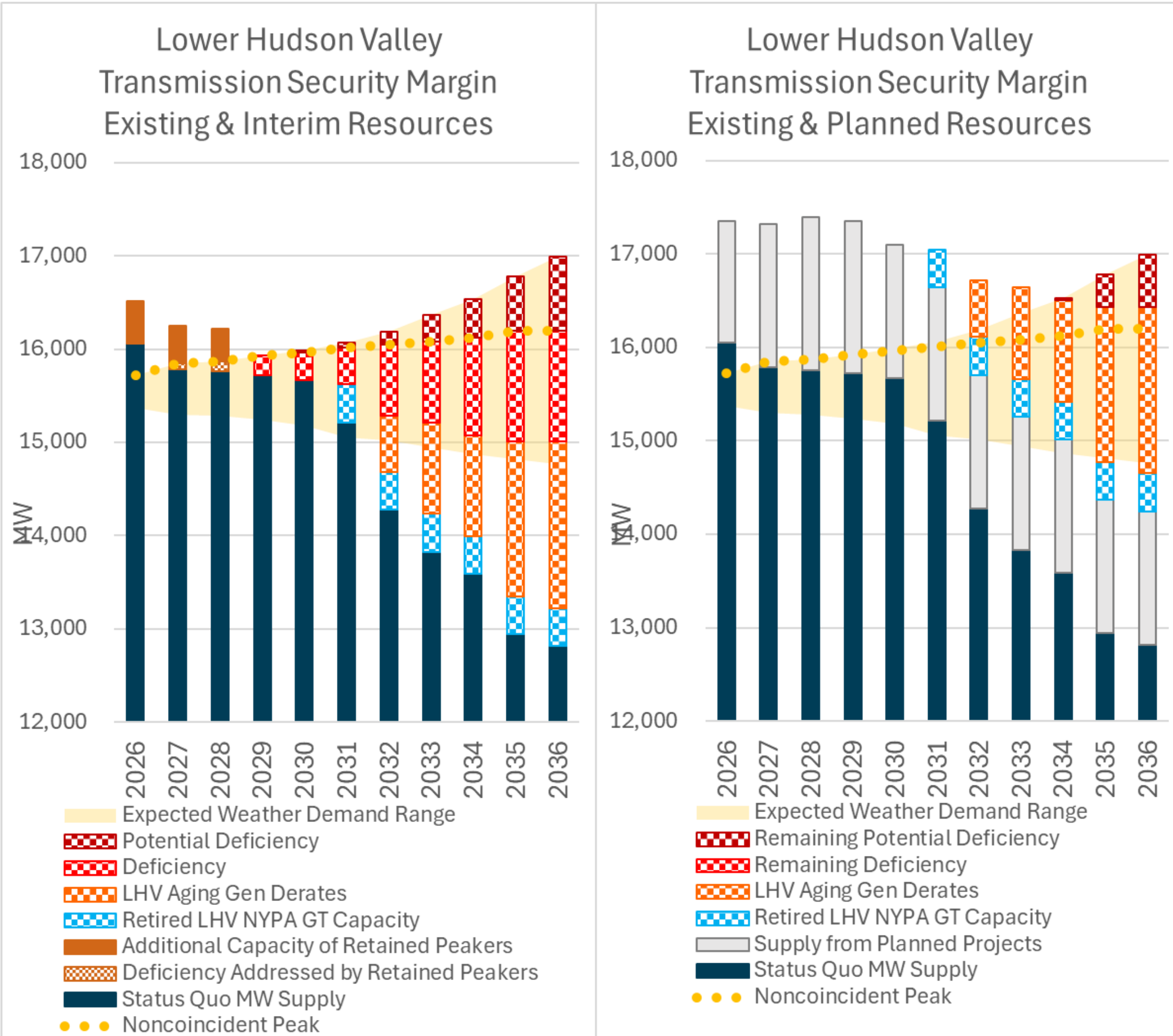
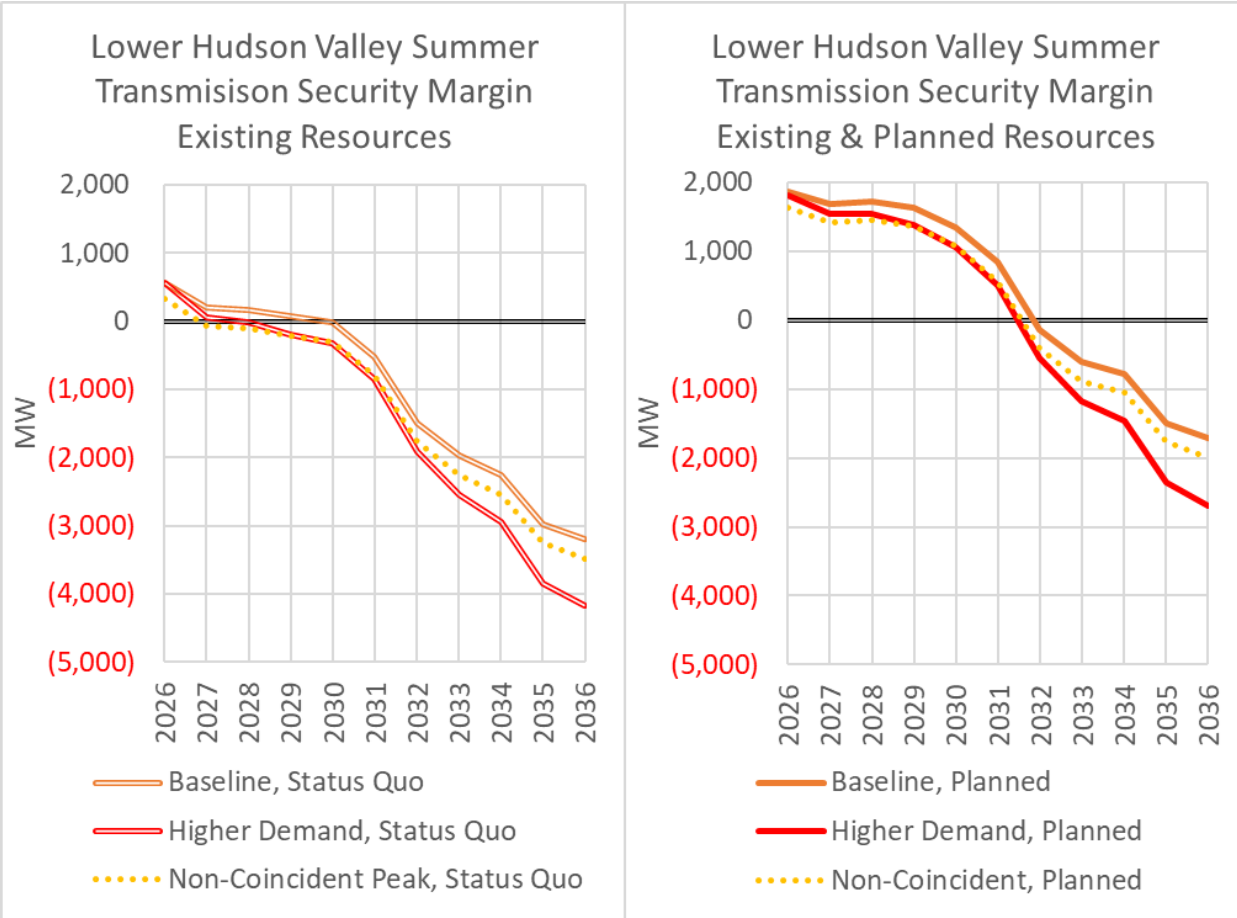


Figure 31: Lower Hudson Valley Transmission Security Margin (2026 RNA Horizon)



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 discusses the selected solutions submitted by Developers and other planned projects that meet the reliability planning process inclusion rules that help address reliability.[26]

Figure 32: Projects Identified to Address New York City Need

Projects to Identifed 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	Summer 2026
	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

Figure 33: Projects Identified to Address Long Island BPTF Need

Projects to Identifed 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

New York City

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. The NYISO now designates the Gowanus 2 & 3 and Narrows 1 & 2 generators (608 MW nameplate)[27] as needed to address ongoing reliability needs until May 1, 2029, the maximum permissible permit extension date allowed, or until

[26] *See* NYISO.com, Planning, Short-Term Reliability Process, Short-Term Reliability Process Solutions, Short-Term Reliability Process Report

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

reliability needs are no longer identified in the NYISO's reliability assessments. AlphaGen, the owner, has proposed to withdraw the generator deactivation notice for these generators.

The retention of the Gowanus and Narrows barges alone is insufficient to address the New York City need, and in the absence of other projects the deficiency would remain unresolved and require reliance on emergency actions to maintain reliability. As planned projects enter service, including Champlain Hudson Power Express ("CHPE") and other planned projects, the margins in New York City improve substantially in the short-term horizon but diminish again in the long-term with demand growth and the risk of aging generation.

Long Island

To address the bulk system need in Long Island the NYISO selects 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. 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. The NYISO will not offer an RMR agreement to Pinelawn Power 1; the Interim Service Provider ("ISP") designation for Pinelawn Power 1 will terminate on May 15, 2026, after which the unit may deactivate. On March 20, 2026 the Office of the State Comptroller approved a capacity purchase agreement between LIPA and MPH Rockaway Peakers, LLC.[28] Following this approval, on March 30th, Hull St. Energy provided to the NYISO notice of their withdrawal of their Generator Deactivation Notices for Far Rockaway GT1 and GT2 effective hour beginning 1:00 on May 1, 2026. The ISP agreement for Far Rockaway 1 and Far Rockaway 2 will terminate on May 1, 2026.

Lower Hudson Valley

The Lower Hudson Valley BPTF Need in this STAR 2026 is primarily driven by the deficiencies in New York City, but is exacerbated by the proposed retirement of Danskammer 1-4 and is also impacted by the deficiency in Long Island. In consideration of the projects identified to address New York City (Figure 32) and Long Island (Figure 33) BPTF Needs, there are sufficient solutions to address the Lower Hudson Valley BPTF Need in the short-term horizon. Upon the planned withdrawal of the Gowanus and Narrows deactivation notice, the deficiencies in summer 2027 and 2028 would be addressed, but the deficiencies in 2029 and 2030 would continue to be observed. While the extension of the Gowanus and Narrows barges would also help to address the Lower

[28] https://www.osc.ny.gov/open-book-new-york

Hudson Valley deficiency, retaining Danskammer 1-4 would not help alleviate the New York City Need. As determined in the 2026 Quarter 1 STAR, Danskammer cannot deactivate until at least August 1, 2026 and may be required to remain in-service until at least January 15, 2027 if the need persists.[29]

Local Non-BPTF Reliability Assessment

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

Central Hudson Non-BPTF Generator Deactivation Assessment

For this STAR, Central Hudson performed a deactivation assessment to evaluate the reliability of the local non-BPTF system for the retirement of Danskammer 1-4. Central Hudson did not identify Generator Deactivation Reliability Needs.

[29] If planned projects fail to timely enter service or otherwise prove insufficient, and the NYISO determines it requires additional solutions to address Lower Hudson Valley needs arising in 2029 and 2030, then the NYISO will conduct a solicitation pursuant to Section 38.4.8.1(c) of the OATT to obtain additional solutions to the identified needs, and may execute an RMR Agreement with Danskammer to allow sufficient time to complete the solicitation process, and/or to address the 2029 and 2030 needs if the solicitation does not produce other viable and sufficient solutions.

Conclusions

Based on the study assumptions presented to stakeholders at the start of this STAR, the reliability needs in New York City and Long Island reliability first observed in the 2025 Quarter 3 STAR continue to be observed. This STAR also finds an exacerbation of the Lower Hudson Valley deficiency first observed in the 2025 Quarter 3 STAR.

Following the start of this STAR the NYISO finalized the evaluation of the solutions provided in response to the November 10, 2025 solution solicitation and issued the Short-Term Reliability Process Report on April 15, 2026 discussing these solutions.

New York City

As discussed in the Short-Term Reliability Process Report, 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. Further, in the Short-Term Reliability Process Report, the NYISO designated the Gowanus 2 & 3 and Narrows 1 & 2 generators as needed to address ongoing reliability needs until May 1, 2029, the maximum permissible permit extension date allowed under the Peaker Rule, or until reliability needs are no longer identified in the NYISO's reliability assessments. AlphaGen, the owner, has proposed to withdraw the generator deactivation notices for these generators.

The retention of the Gowanus and Narrows barges alone is insufficient to address the New York City BPTF Need, and in the absence of other projects the deficiency would remain unresolved and require reliance on emergency actions to maintain reliability. As planned projects enter service, including Champlain Hudson Power Express ("CHPE") and other planned projects, the margins in New York City improve substantially over the short-term horizon, but diminish again over the longer-term with demand growth and the risk of aging generation.

Long Island

To address the Long Island BPTF Need the NYISO selects 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. The solutions for the Long Island Non-BPTF Need are the Far Rockaway 2 unit and local transmission upgrades that went into service in December 2025. As discussed in the Short-Term Reliability Process Report, the NYISO will not offer an RMR agreement to Pinelawn Power 1; the ISP agreement for Pinelawn Power 1 will terminate on May 15, 2026, after which the unit may deactivate.[30] Effective with the service commencement date for Far Rockaway 1 and Far Rockaway 2, the ISP agreement for these units will terminate on May 1, 2026.

Lower Hudson Valley

The Lower Hudson Valley is observed to first have a deficiency starting in summer 2027 of 17-27 MW for the peak hour in summer 2027 which grows to 202-639 MW over a period of 3-6 hours in summer 2030. The deficiency in this locality is primarily driven by the deficiencies in Zone J, but is exacerbated by the proposed retirement of Danskammer 1-4 and is also impacted by the deficiency in Long Island. This deficiency is a Near-Term Reliability Need and also a Generator Deactivation Reliability Need.

As the Lower Hudson Valley Need that would be resolved in whole or in part by the retention of Danskammer 1-4, these units may not deactivate prior to the expiration of the 365-day notice period (*i.e.,* before January 15, 2027).[31] However, should sufficient system plans, as discussed in the Short-Term Reliability Process Report, be in-service prior to August 1, 2026 (the Danskammer 1-4 proposed deactivation date) that would address the deficiency over the entire short-term horizon, and have demonstrated their planned capabilities, then Danskammer 1-4 may be able to deactivate after on or after August 1, 2026. If necessary, Danskammer 1-4 would be compensated under an ISP rate commencing August 1, 2026.[32] Should sufficient solutions and other planned projects identified in the Short-Term Reliability Process Report be in-service prior to August 1, 2026 the ISP rate may not be executed as the unit would not be needed for reliability.

[30] Consistent with Section 38.3.7 of the OATT, the earliest possible retirement date for Hull Street Energy, LLC generator, Pinelawn Power 1 is May 15, 2026. Hull Street Energy, LLC must complete all required NYISO administrative process and procedures prior to retirement of its generating unit. See NYISO Technical Bulletin 185. The NYISO's determination in this Short-Term Reliability Process does not relieve Hull Street Energy, LLC of any obligations they have with respect to its Generators participation in the NYISO markets. Hull Street will be required to repay study cost in accordance with Section 38.14 of the OATT for its Far Rockaway GTs. If Hull Street Energy, LLC rescinds its Generator Deactivation Notice or does not retire Pinelawn within 730 days of July 15, 2025, then Hull Street 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.

[31] Consistent with Section 38.3.7 of the OATT, the earliest possible retirement date for Danskammer Energy, LLC generators Danskammer 1-4 is January 15, 2027 unless sufficient plans are in-service by August 1, 2026 in New York City and Long Island to address the Generator Deactivation Reliability Need observed in this report. Danskammer Energy, LLC must complete all required NYISO administrative processes and procedures prior to retirement of their generating units. See NYISO Technical Bulletin 185. The NYISO's determination in this Short-Term Reliability Process does not relive Danskammer Energy, LLC of any obligations they have with respect to their Generators participation in the NYISO markets. If Danskammer Energy, LLC rescinds their Generator Deactivation Notice or does not retire their units within 730 days of January 15, 2026, then they 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 costs in accordance with Section 38.14 of the OATT.

[32] If planned projects fail to timely enter service or otherwise prove insufficient, and the NYISO determines it requires additional solutions to address Lower Hudson Valley needs arising in 2029 and 2030, then the NYISO will conduct a solicitation pursuant to Section 38.4.8.1(c) of the OATT to obtain additional solutions to the identified needs, and may execute an RMR Agreement with Danskammer to allow sufficient time to complete the solicitation process, and/or to address the 2029 and 2030 needs if the solicitation does not produce other viable and sufficient solutions.

Next Steps

The Short-Term Reliability Process Needs observed in this STAR in the Lower Hudson Valley are Near-Term Reliability Needs and Generator Deactivation Reliability Needs. As this is a change in scope or scale of the Need first observed in the 2025 Quarter 3 STAR the NYISO has determined that the solutions to this need are addressed through the solutions and other projects discussed in the April 15, 2026 Short-Term Reliability Process Report.

The 2026 RNA will evaluate the reliability of the New York bulk electric grid over the ten-year planning horizon, with a focus on 2030-2036, considering updated forecasts of grid demand according to the 2026 Gold Book, planned transmission upgrades, and projected changes to the generation fleet.

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.

Appendix A: List of Short-Term Reliability Needs

New York City Generator Deactivation Reliability Needs

Listed below are the Generator Deactivation Reliability Needs in the New York City locality in the November 10, 2025 solution solicitation.

BPTF Deficiencies:

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

Long Island Generator Deactivation Reliability Needs

Listed below are the Generator Deactivation Reliability Needs in the Long Island locality as detailed in the November 10, 2025 solicitation letter.

BPTF Deficiencies:

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

Non-BPTF Deficiencies (Far Rockaway Load Pocket)

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

Lower Hudson Valley Deactivation Reliability Needs

Listed below are the Generator Deactivation Reliability Needs in the Lower Hudson Valley locality identified in this STAR.

Lower Hudson Valley BPTF Deficiencies:

Summer Peak	**2026**	**2027**	**2028**	**2029**	**2030**
MW Deficiency	None	17-27	69-184	121-383	202-639
Duration (hours)	None	1	3	3-4	3-6
MWh	None	17-27	396-756	521-1,446	718-2,663

Appendix B: Short-Term Reliability Process Solution List

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

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

Appendix C: Summary of Study Assumptions

This assessment used the major assumptions included in the 2024 RNA, with the key updates noted below. Consistent with the NYISO's obligations under its tariffs, the NYISO provided information to stakeholders on the modeling assumptions employed in this assessment. Details regarding the 2024 RNA study assumptions were reviewed with stakeholders at the April 18, 2024, joint Electric System Planning Working Group ("ESPWG")/Transmission Planning Advisory Subcommittee ("TPAS") meeting. Details regarding the 2026 Quarter 1 STAR study assumptions were reviewed with stakeholders at the February 3, 2026, joint ESPWG/ TPAS meeting. The meeting materials are posted on the NYISO's website.[33] The figures below (Figure 34, Figure 35, Figure 36, and Figure 37) summarize the changes to generation, load, and transmission.

Generation Assumptions

[33] Short-Term Assessment of Reliability: 2026 Q1 Key Study Assumptions, ESPWG/TPAS, February 3, 2026 (here). 2024 RNA Key Study Assumptions, ESPWG/TPAS, April 18, 2024 (here),

Figure 34: Completed Generator Deactivations

Owner/ Operator	Plant Name	Zone	Nameplate (MW)	CRIS (MW)		Capability (MW)		Status	Deactivation Date (2)	STAR Evaluation (3)
				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
		Total	4,603.8	4,210.7	4,537.3	4,009.8	4,378.7			

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

Figure 35: Proposed Deactivations

Owner/ Operator	Plant Name (1)	Zone	Nameplate (MW)	CRIS (MW)		Capability (MW)		Status	Deactivation date (2)	STAR Evaluation
				Summer	Winter	Summer	Winter			
Central Hudson Gas & Electric Corp.	Coxsackie GT	G	21.6	21.6	26.0	19.7	22.7	R	12/31/2025 (3)	2024 Q1
MPH Cross Island Power, LLC	Pinelawn Power 1	K	82	78.0	78.0	73.6	76.5	R	11/1/2025	2025 Q3
MPH Rockaway Peakers, LLC	Far Rockaway GT1	K	60.5	53.5	73.1	48.9	52.6	R	11/1/2025	2025 Q3
MPH Rockaway Peakers, LLC	Far Rockaway GT2	K	60.5	55.4	75.7	55.7	59.0	R	11/1/2025	2025 Q3
Astoria Generating Company, L.P.	Gowanus 2-1 through 2-8	J	160	152.8	199.6	142.2	182.5	R	7/14/2026	2025 Q3
Astoria Generating Company, L.P.	Gowanus 3-1 through 3-8 (4)	J	140	129.2	168.7	123.8	159.7	R	7/14/2026	2025 Q3
Astoria Generating Company, L.P.	Narrows 1-1 through 2-8 (5)	J	308	269.0	351.3	250.4	323.7	R	7/14/2026	2025 Q3
Danskammer Energy, LLC	Danskammer Units 1 through 4	G	532	511.1	511.1	498.3	505.0	R	8/1/2026	2026 Q1
		Total	1364.6	1270.6	1483.5	1212.6	1381.7			

Notes:

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

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

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

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

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

Figure 36: Large Generation Additions

Proposed Project Inclusion: Large Generation						
Queue	**Project Name**	**MW**	**Type**	**Zone**	**Proposed Date**	**Included in Prior STAR**
396	Baron Winds Phase II	117	W	C	Dec-25	Yes
571	Heritage Wind, LLC	200.1	W	B	Sep-26	Yes
596	Alle Catt II Wind	339.1	W	A	Dec-26	Yes
704	Bear Ridge Solar	100	S	A	Apr-27	Yes
720	Trelinia Solar Energy Center	80	S	C	Apr-28	Yes
721	Excelsior Energy Center	280	S	A	Nov-26	Yes
737	Empire Wind 1	816	W	J	Jul-27	Yes
811	Hecate Energy Cider Solar LLC	500	S	B	Jan-27	Yes
880	Brookside Solar	100	S	D	Dec-27	Yes
883	Garnet Energy Center, LLC	200	S	B	Apr-28	Yes
950	Hemlock Ridge Solar	200	S	B	Apr-28	Yes
1079	Somerset Solar	125	S	A	Jun-28	Yes
766/987	Sunrise Wind LLC	924	W	K	Jul-27	Yes
931	Astoria Energy Storage	100	ES	J	Jun-26	No

Figure 37: Small Generation Additions

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

*All projects have CRIS.

Demand Assumptions

The 2026 Quarter 1 STAR uses the demand forecasts for the study years consistent with the 2025 Gold Book for expected weather conditions with changes to Zone K to account for the removal of certain load projects. Details on the demand forecasts utilized for determining reliability needs are provided below.

Figure 38: Summer Coincident Peak Demand Forecasts

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

Figure 39: Winter Coincident Peak Demand Forecasts

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

Figure 40: Annual Energy Forecasts

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

Figure 41: Summer Non-Coincident Peak Demand Forecast

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

Figure 42: Winter Non-Coincident Peak Demand Forecast

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

Figure 43: Large Load Demand Forecast

Large Loads Summer Peak Forecasts (MW)

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

Large Loads Winter Peak Forecasts (MW)

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

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

Transmission Assumptions

The study assumptions for existing transmission facilities that are modeled as out-of-service are listed in Figure 44. Figure 45 shows the Con Edison series reactor status utilized in this STAR. There is one change in Con Edison series reactor assumptions in this STAR compared to the 2024 RNA. Figure 46 and Figure 47 provide a summary of the transmission projects included in the 2024 RNA as listed in the 2025 Gold Book.

Figure 44: Existing Transmission Facilities Modeled Out-of-Service

From	To	kV	ID	Out-of-Service Through	
				Prior STAR	Current STAR
Marion	Farragut	345	B3402	Long-Term	
Marion	Farragut	345	C3403	Long-Term	
Plattsburgh (1)	Plattsburgh	230/115	AT1	9/2026	
Stolle Rd	Stolle Rd	115	T11-52	12/2025	7/2026
Station 23	Station 42	115	920	12/2025	12/2026
E13th Street		345/69	BK17	6/2027	
Oakdale (Cap Bank)		345	C1	-	6/2026

Notes

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

Figure 45: Con Edison Proposed Series Reactor Status

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

Figure 46: Major Transmission Projects Included in 2024 RNA

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

Figure 47: Transmission Project Inclusion Rules Application for 2024 RNA

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

Appendix D: Resource Adequacy Assumptions

2025 Q4 STAR MARS Assumptions Matrix

	Parameter	2024 RNA Base Cases Key Assumptions (2024 Gold Book)	2025 RPP, 2025 Q3, Q4 STAR 2026 Q1 STAR Key Assumptions (2025 GB)
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 • Feb. 3 ESPWG 2026 Q1 STAR Assumptions
Load Parameters			
1	**Peak** Load Forecast	Adjusted 2024 Gold Book NYCA baseline peak load forecast. It includes large loads from the NYISO interconnection queue, with forecasted impacts. Baseline load represents coincident summer peak demand and includes the reductions due to projected energy efficiency programs, building codes and standards, BtM storage impacts at peak, distributed energy resources and BtM solar photovoltaic resources; it also reflects expected impacts (increases) from projected electric vehicle usage and electrification. 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.
1a	Proposed large loads	As included in the Baseline Peak Load Forecast from the Gold Book. Certain large loads that are assumed flexible (e.g., crypto, hydrogen) are modeled as EOP step.	As included in the Baseline Peak Load Forecast from the Gold Book. Certain large loads that are assumed flexible (e.g., crypto, hydrogen) are modeled as EOP step.
2	Load **Shapes** (Multiple Load Shapes)	Used Multiple Load Shape MARS Feature *(see March 24, 2022 LFTF/ESPWG).* 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 March 24, 2022 LFTF/ESPWG).* 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	Same summer LFU values as the ones presented in 2023 *(as presented at the May 26, 2023 LFTF [link] and also presented at the April 18, 2024 LFTF [link])*	Same summer LFU values as the ones presented in 2023 *(as presented at the May 26, 2023 LFTF [link] and also presented at the April 18, 2024 LFTF [link])*

	impacts of weather conditions on future loads.	**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 (winter 2024-25) match those calculated using recent winter load and weather data. Additional details are available in the April 18 TPAS/ESPWG/LFTF presentation [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 (winter 2024-25) match those calculated using recent winter load and weather data. Additional details are available in the May 29 TPAS/ESPWG/LFTF presentation [link]
Generation Parameters			
1	**Existing** Generating Unit Capacities (*e.g., thermal units, large hydro)*	2024 Gold Book values: 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
2	**Proposed New Units Inclusion** Determination	2024 Gold Book with RNA Base Case inclusion rules applied	2025 Gold Book with RNA Base Case inclusion rules applied
3	Retirement, Mothballed Units, IIFO	2024 Gold Book with RNA Base Case inclusion rules applied	2025 Gold Book with RNA Base Case inclusion rules applied
4	Forced and Partial Outage Rates (*e.g., thermal units)*	Five-year (2019-2023) GADS data for each unit represented. 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.
5	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-burn capability are derated. The forecasted winter coincident peak is used to determine when the gas derates are applied in the RNA Base Cases and for each load bin and Study Year.	**Starting 2024 RNA:** In order to simulate anticipated risks from cold snaps on the gas availability, gas plants available MWs in NYCA are further derated*, i.e.,* all gas-only units with non-firm gas within the NYCA are assumed unavailable**.** Also, certain dual-fuel units with duct-burn capability are derated. The forecasted winter coincident peak is used to determine when the gas derates are applied in the RNA Base Cases and for each load bin and Study Year.
6	Daily Maintenance	Fixed maintenance based on schedules received by the NYISO.	Fixed maintenance based on schedules received by the NYISO.
7	Weekly Planned Maintenance	MARS is automatically scheduling maintenance based on NYCA capacity and demand. Data: 5y (2019-2023) of historical scheduled maintenance data from Operations and GADS	MARS is automatically scheduling maintenance based on NYCA capacity and demand. Data: 5y (2020-2024) of historical scheduled maintenance data from Operations and GADS

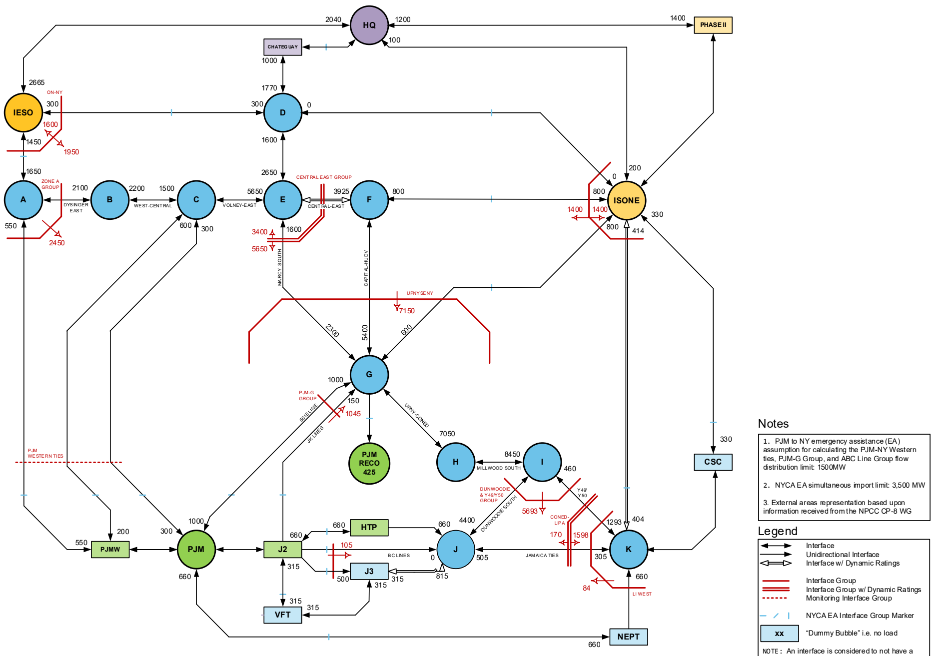
		system to determine the number of weeks on maintenance for each thermal unit.	system to determine the number of weeks on maintenance for each thermal unit.
8	Summer Maintenance	None	None
9	Combustion Turbine Derates	Derate based on temperature correction curves. Thermal derates are based on a ratio of 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.
10	Existing Landfill Gas (LFG) Plants	Actual hourly plant output over the last 5 years. Program randomly selects an LFG shape of hourly production over the last 5 years for each model replication. Probabilistic model is incorporated based on five years of input shapes, with one shape per replication randomly selected in the Monte Carlo process.	Actual hourly plant output over the last 5 years. Program randomly selects an LFG shape of hourly production over the last 5 years for each model replication. Probabilistic model is incorporated based on five years of input shapes, with one shape per replication randomly selected in the Monte Carlo process.
11	Existing and Proposed **Wind** Units	**New data source:** Model-based hourly data over the available past 5 years (2017-2021 developed by DNV-GL). For any unit that was included in the DNV data the data "as is" was used. For any unit not included a weighted zonal average was modeled. Probabilistic model is incorporated based on five years of input shapes with one shape per replication being randomly selected in Monte Carlo process.	**Starting 2024 RNA, new data source:** Model-based hourly data over the available past 5 years (2020-2024 developed by DNV-GL). For any unit that was included in the DNV data the data "as is" was used. For any unit not included a weighted zonal average was modeled. Probabilistic model is incorporated based on five years of input shapes with one shape per replication being randomly selected in Monte Carlo process.
12	Existing and Proposed **Offshore Wind** Units	RNA Base Case inclusion rules Applied to determine the generator status. **New data source:** 5 years of hourly model-based data as developed by DNV-GL (2017-2021)	RNA Base Case inclusion rules Applied to determine the generator status. 5 years of hourly model-based data as developed by DNV-GL (2020-2024)
13	Existing and Proposed **Utility-scale Solar Resources**	**New data source:** Probabilistic model chooses from the model-based data shapes covering past available 5 years (2017-2021), as developed by DNV-GL. One shape per replication is randomly selected in Monte Carlo process.	Probabilistic model chooses from the model-based data shapes covering past available 5 years (2020-2024), as developed by DNV-GL. One shape per replication is randomly selected in Monte Carlo process.
14	**BtM Solar Resources**	**Supply side:** Past five years (2017-2021) of 8,760 hourly MW profiles based on sampled inverter data. The MARS random shape mechanism randomly picks one 8,760 hourly shape (of five) for each replication year; similar with the past planning modeling and aligns with the method used for wind, utility solar, landfill gas, and run-of-river facilities. **Load side:** Gross load forecasts	**Supply side:** Past five years (2020-2024) of 8,760 hourly MW profiles based on sampled inverter data. The MARS random shape mechanism randomly picks one 8,760 hourly shape (of five) for each replication year; similar with the past planning modeling and aligns with the method used for wind, utility solar, landfill gas, and run-of-river facilities. **Load side:** Gross load forecasts
15	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.

16	Existing **Small Hydro** Resources (*e.g.,* run of river)	Actual hourly plant output over the past 5 years period. Program randomly selects a hydro shape of hourly production over the 5-year window for each model replication. The randomly selected shape is multiplied by their current nameplate rating.	Actual hourly plant output over the past 5 years period. Program randomly selects a hydro shape of hourly production over the 5-year window for each model replication. The randomly selected shape is multiplied by their current nameplate rating.
17	Existing **Large Hydro**	Probabilistic Model based on 5 years of GADS data. 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.
18	Proposed front-of-meter **Battery Storage**	GE MARS 'ES' model is used. Units are given a maximum capacity, maximum stored energy, and a dispatch window.	GE MARS 'ES' model is used. Units are given a maximum capacity, maximum stored energy, and a dispatch window.
19	Existing Energy Limited Resources (**ELRs**)	GE developed MARS functionality to be used for ELRs. Resource output is aligned with the NYISO's peak load window when most loss-of-load events are expected to occur.	GE developed MARS functionality to be used for ELRs. Resource output is aligned with the NYISO's peak load window when most loss-of-load events are expected to occur.
Transaction – Imports/ Exports			
1	Capacity Purchases	Grandfathered Rights and other awarded long-term rights 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
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
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.
5	External Deliverability Rights (EDRs)	Cedars Uprate 80 MW. Modeled reflecting External CRIS rights.	Cedars Uprate 80 MW. Modeled reflecting External CRIS rights.
6	Wheel-Through Contract	300 MW HQ through NYISO to ISO-NE. 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.
MARS Topology: a simplified bubble-and-pipe representation of the transmission system			
1	Interface Limits	Developed by review of previous studies and specific analysis prior and during the RNA study process.	Developed by review of previous studies and specific analysis prior and during the RNA study process. **Starting with the 2025 models, Chateaugay to NY limit set to zero for winter.**

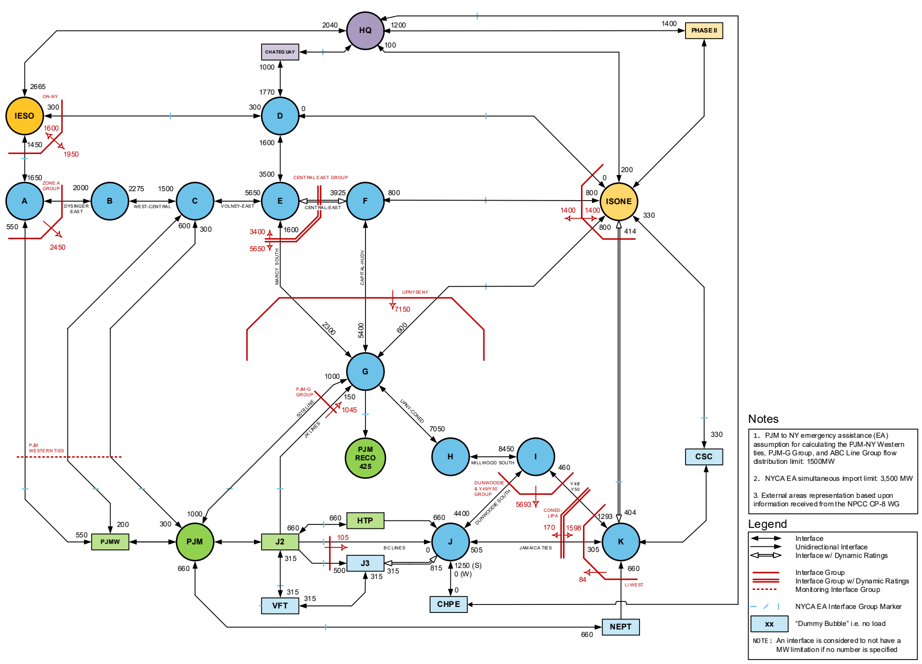
2	New Transmission	Based on TO-provided firm plans via Gold Book/LTP 2024 processes) and proposed merchant transmission and public policy facilities meeting the RNA Base Case inclusion rules.	Based on TO-provided firm plans (via Gold Book/LTP 2025 processes) and proposed merchant transmission and public policy facilities meeting the Base Case inclusion rules.
3	AC Cable Forced Outage Rates	All existing cable transition rates updated with data received from ConEd and PSEG-LIPA to reflect most recent five-year history.	All existing cable transition rates updated with data received from ConEd and PSEG-LIPA to reflect most recent ten-year history.
4	UDR unavailability	Five-year history of forced outages.	Ten-year history of forced outages.
Emergency Operating Procedures (EOPs)			
1	EOP Steps Order	**New order, and new flexible large loads at step 2:** 1. No EOP Support 2. Flexible Large Loads (400-900 MW) 3. Special Case Resources (SCRs) (Load and Generator) 4. 5% Manual Voltage Reduction 5. 30-Minute Operating Reserve to Zero (655 MW) 6. Voluntary Load Curtailment 7. Public Appeals 8. 5% Remote Controlled Voltage Reduction 9. Emergency Assistance from External Areas 10. Part of the 10-Minute Operating Reserve (910 MW of 1310 MW) to Zero	**Starting 2024 RNA, new EOP order and flexible large loads:** 1. No EOP Support 2. Flexible Large Loads (about 485 MW at max) 3. Special Case Resources (SCRs) (Load and Generator) 4. 5% Manual Voltage Reduction 5. 30-Minute Operating Reserve to Zero (655MW) 6. Voluntary Load Curtailment 7. Public Appeals 8. 5% Remote Controlled Voltage Reduction 9. Emergency Assistance from External Areas 10. Part of the 10-Minute Operating Reserve (910 MW of 1310 MW) to Zero
2	Special Case Resources (SCR)	SCRs sold for the program discounted to historic availability ("effective capacity"). Monthly variation based on historical experience. 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 determined based on historical SCR performance in the applicable zone. Hourly response rates are used. The contribution by the SCRs vary monthly by applicable zone. These monthly values are also derived from historical performance of the SCRs. Additional details in the January 3, 2024 ICS/ICAP presentation [link] and May 1, 2024 ICS [link].	SCRs sold for the program discounted to historic availability ("effective capacity"). Monthly variation based on historical experience. Summer values calculated from the latest available July registrations (July 2024 SCR enrollment) held constant for all years of study. **Starting 2024 RNA, 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 determined based on historical SCR performance in the applicable zone. Hourly response rates are used. The contribution by the SCRs vary monthly by applicable zone. These monthly values are also derived from historical performance of the SCRs. Additional details in the January 3, 2024 ICS/ICAP presentation [link] and May 1, 2024 ICS [link].
3	EDRP Resources	Not modeled if the values are less than 2 MW.	Not modeled if the values are less than 2 MW.
4	Operating Reserves	655 MW 30-min reserve to zero 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).
5	Other EOPs *(e.g., manual voltage reduction, voltage curtailments, public*	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.

	appeals, external assistance, as listed above)		
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. • LFU is applied to neighboring systems. • Same load historical years are used as NY.			
1	PJM	Simplified model: The 5 PJM MARS areas (bubbles) were consolidated into one starting 2020 RNA. As per RNA procedure.	Simplified model: The 5 PJM MARS areas (bubbles) were consolidated into one starting 2020 RNA. As per RNA procedure.
2	ISONE	Simplified model: The 8 ISO-NE MARS areas (bubbles) were consolidated into one starting 2020 RNA	Simplified model: The 8 ISO-NE MARS areas (bubbles) were consolidated into one starting 2020 RNA
3	HQ	Per RNA Procedure.	Per RNA Procedure.
4	IESO	Per RNA procedure.	Per RNA procedure.
5	Reserve Sharing	All NPCC Control Areas indicate that they will share reserves equally among all members before sharing with PJM.	All NPCC Control Areas indicate that they will share reserves equally among all members before sharing with PJM.
6	NYCA Emergency Assistance Limit	Implemented a statewide limit of 3,500 MW, additional to the “pipe” limits.	Implemented a statewide limit of 3,500 MW, additional to the “pipe” limits.
Miscellaneous			
1	MARS Model Version	4.14.2179	5.7.3765

2024 RNA MARS Topology[34]



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



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

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

Appendix E: Transmission Security Margin Assessment

Introduction

The purpose of this assessment is to identify plausible changes in conditions or assumptions that might adversely impact the reliability of the BPTF or "tip" the system into a violation of a transmission security criterion. This assessment is performed using a deterministic approach through a spreadsheet-based method using input from the 2025 Gold Book and the projects that meet the reliability planning inclusion rules for the 2026 Quarter 1 STAR. For this assessment, the statewide system margin is calculated and transmission security margins for the Lower Hudson Valley, New York City, and Long Island localities are calculated.

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

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

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

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

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

Statewide System Margin

The statewide system margin for New York is evaluated under expected weather for summer and winter conditions with normal transfer criteria. The statewide system margin is the ability to meet the forecasted load and largest loss-of-source contingency (*i.e.,* total capacity requirement) against the NYCA generation (including derates) and external area interchanges. The NYCA generation (from line-item A in the following figures) is comprised of the existing generation plus additions of future generation resources, as well as the removal of deactivating generation, that meet the reliability planning process inclusion rules. The dispatch of renewable generation is aligned with current transmission planning practices for transmission security. Derates for thermal resources based on their NERC five-year class average EFORd are also included.[35] Additionally, for the statewide system margin, the NYCA generation includes the Oswego export limit with all lines in service.

The decreasing statewide system margin in both summer and winter can be attributed to increasing demand that is not matched by incoming proposed generation that meets inclusion rules. Additionally, the unavailability of non-firm gas is a key driver of deficient statewide margins in the winter peak condition. A negative statewide system margin is not, on its own, a violation of the Reliability Criteria. It is, however, a leading indicator of the system's inability to securely serve demand under normal operations. This metric is further explored in the 2025-2034 CRP.[36]

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

Figure 48: Summer Peak Statewide System Margin Calculation - Planned System, Flexible Large Loads Offline

Line	Item	Summer Peak - Expected Summer Weather, Normal Transfer Criteria (MW)								
		2026	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**
A	NYCA Generation (1)	37,209	40,102	41,406	41,406	41,406	40,951	40,951	40,951	40,951
B	NYCA Generation Unavailability (2)	(6,633)	(9,181)	(10,350)	(10,376)	(10,401)	(10,380)	(10,405)	(10,405)	(10,431)
C	Temperature Based Generation Derates	0	0	0	0	0	0	0	0	0
D	External Area Interchanges (3)	3,208	2,919	2,919	2,919	2,919	2,919	2,919	2,919	2,919
E	**Total Resources (A+B+C+D)**	33,783	33,840	33,975	33,949	33,924	33,491	33,465	33,465	33,439
F	Demand Forecast (5)	(31,305)	(31,590)	(31,698)	(31,886)	(32,160)	(32,434)	(32,757)	(33,101)	(33,399)
G	Largest Loss-of-Source Contingency	(1,310)	(1,310)	(1,310)	(1,310)	(1,310)	(1,310)	(1,310)	(1,310)	(1,310)
H	**Total Capability Requirement (F+G)**	(32,615)	(32,900)	(33,008)	(33,196)	(33,470)	(33,744)	(34,067)	(34,411)	(34,709)
I	**Statewide System Margin (E+H)**	1,168	940	967	753	454	(253)	(602)	(946)	(1,270)
J	Higher Demand Impact	(600)	(1,170)	(1,650)	(2,050)	(2,330)	(2,520)	(2,660)	(2,830)	(3,160)
K	**Higher Demand Statewide System Margin (I+J)**	568	(230)	(683)	(1,297)	(1,876)	(2,773)	(3,262)	(3,776)	(4,430)
L	SCRs (6), (7)	804	804	804	804	804	804	804	804	804
M	**Statewide System Margin with SCR (K+L)**	1,372	574	121	(493)	(1,073)	(1,970)	(2,458)	(2,972)	(3,626)
N	Operating Reserve	(1,310)	(1,310)	(1,310)	(1,310)	(1,310)	(1,310)	(1,310)	(1,310)	(1,310)
O	**Statewide System Margin with Full Operating Reserve (M+N) (4)**	62	(736)	(1,189)	(1,803)	(2,383)	(3,280)	(3,768)	(4,282)	(4,936)

Notes:

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

Figure 49: Winter Peak Statewide System Margin – Planned System, Flexible Large Loads Offline

Line	Item	Winter Peak - Baseline Expected Winter Weather, Normal Transfer Criteria (MW)								
		2026-27	2027-28	2028-29	2029-30	2030-31	2031-32	2032-33	2033-34	2034-35
A	NYCA Generation (1)	41,732	43,101	43,481	43,481	43,023	43,023	43,023	43,023	43,023
B	NYCA Generation Unavailability (2)	(8,677)	(9,861)	(10,241)	(10,241)	(10,241)	(10,241)	(10,241)	(10,241)	(10,241)
C	Unavailability of Non-Firm Gas (6)	(5,823)	(5,823)	(5,823)	(5,823)	(5,365)	(5,365)	(5,365)	(5,365)	(5,365)
D	Temperature Based Generation Derates	0	0	0	0	0	0	0	0	0
E	External Area Interchanges (3)	849	560	560	560	560	560	560	560	560
F	**Total Resources (A+B+C+D+E)**	28,080	27,977	27,977	27,977	27,977	27,977	27,977	27,977	27,977
G	Demand Forecast (5)	(24,920)	(25,316)	(25,815)	(26,365)	(27,026)	(27,671)	(28,378)	(29,146)	(29,905)
H	Large Load Flexibility	0	0	0	0	0	0	0	0	0
I	Largest Loss-of-Source Contingency	(1,310)	(1,310)	(1,310)	(1,310)	(1,310)	(1,310)	(1,310)	(1,310)	(1,310)
J	**Total Capability Requirement (G+H+I)**	(26,230)	(26,626)	(27,125)	(27,675)	(28,336)	(28,981)	(29,688)	(30,456)	(31,215)
K	**Statewide System Margin (F+J)**	1,850	1,351	852	302	(359)	(1,004)	(1,711)	(2,479)	(3,238)
L	SCRs (7), (8)	721	721	721	721	721	721	721	721	721
M	**Statewide System Margin with SCR (K+L)**	2,571	2,071	1,572	1,022	361	(284)	(991)	(1,759)	(2,518)
N	Operating Reserve	(1,310)	(1,310)	(1,310)	(1,310)	(1,310)	(1,310)	(1,310)	(1,310)	(1,310)
O	**Statewide System Margin with Full Operating Reserve (M+N) (4)**	1,261	761	262	(288)	(949)	(1,594)	(2,301)	(3,069)	(3,828)

Notes:

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

Figure 50: Summer Peak Statewide System Margin Calculation – Planned System, Flexible Large Loads Online

Line	Item	Summer Peak - Expected Summer Weather, Normal Transfer Criteria (MW)								
		2026	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**
A	NYCA Generation (1)	37,209	40,102	41,406	41,406	41,406	40,951	40,951	40,951	40,951
B	NYCA Generation Unavailability (2)	(6,633)	(9,181)	(10,350)	(10,376)	(10,401)	(10,380)	(10,405)	(10,405)	(10,431)
C	Temperature Based Generation Derates	0	0	0	0	0	0	0	0	0
D	External Area Interchanges (3)	3,208	2,919	2,919	2,919	2,919	2,919	2,919	2,919	2,919
E	**Total Resources (A+B+C+D)**	33,783	33,840	33,975	33,949	33,924	33,491	33,465	33,465	33,439
F	Demand Forecast (5)	(31,990)	(32,275)	(32,383)	(32,571)	(32,845)	(33,119)	(33,442)	(33,786)	(34,084)
G	Largest Loss-of-Source Contingency	(1,310)	(1,310)	(1,310)	(1,310)	(1,310)	(1,310)	(1,310)	(1,310)	(1,310)
H	**Total Capability Requirement (F+G)**	(33,300)	(33,585)	(33,693)	(33,881)	(34,155)	(34,429)	(34,752)	(35,096)	(35,394)
I	**Statewide System Margin (E+H)**	483	255	282	68	(231)	(938)	(1,287)	(1,631)	(1,955)
J	Higher Demand Impact	(600)	(1,170)	(1,650)	(2,050)	(2,330)	(2,520)	(2,660)	(2,830)	(3,160)
K	**Higher Demand Statewide System Margin (I+J)**	(117)	(915)	(1,368)	(1,982)	(2,561)	(3,458)	(3,947)	(4,461)	(5,115)
L	SCRs (6), (7)	804	804	804	804	804	804	804	804	804
M	**Statewide System Margin with SCR (K+L)**	687	(111)	(564)	(1,178)	(1,758)	(2,655)	(3,143)	(3,657)	(4,311)
N	Operating Reserve	(1,310)	(1,310)	(1,310)	(1,310)	(1,310)	(1,310)	(1,310)	(1,310)	(1,310)
O	**Statewide System Margin with Full Operating Reserve (M+N) (4)**	(623)	(1,421)	(1,874)	(2,488)	(3,068)	(3,965)	(4,453)	(4,967)	(5,621)

Notes:

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

Figure 51: Winter Statewide System Margin Calculation – Planned System Flexible Large Loads Online

Line	Item	Winter Peak - Baseline Expected Winter Weather, Normal Transfer Criteria (MW)								
		2026-27	2027-28	2028-29	2029-30	2030-31	2031-32	2032-33	2033-34	2034-35
A	NYCA Generation (1)	41,732	43,101	43,481	43,481	43,023	43,023	43,023	43,023	43,023
B	NYCA Generation Unavailability (2)	(8,677)	(9,861)	(10,241)	(10,241)	(10,241)	(10,241)	(10,241)	(10,241)	(10,241)
C	Unavailability of Non-Firm Gas (6)	(5,823)	(5,823)	(5,823)	(5,823)	(5,365)	(5,365)	(5,365)	(5,365)	(5,365)
D	Temperature Based Generation Derates	0	0	0	0	0	0	0	0	0
E	External Area Interchanges (3)	849	560	560	560	560	560	560	560	560
F	**Total Resources (A+B+C+D+E)**	28,080	27,977	27,977	27,977	27,977	27,977	27,977	27,977	27,977
G	Demand Forecast (5)	(24,920)	(25,316)	(25,815)	(26,365)	(27,026)	(27,671)	(28,378)	(29,146)	(29,905)
H	Large Load Flexibility	685	685	685	685	685	685	685	685	685
I	Largest Loss-of-Source Contingency	(1,310)	(1,310)	(1,310)	(1,310)	(1,310)	(1,310)	(1,310)	(1,310)	(1,310)
J	**Total Capability Requirement (G+H+I)**	(25,545)	(25,941)	(26,440)	(26,990)	(27,651)	(28,296)	(29,003)	(29,771)	(30,530)
K	**Statewide System Margin (F+J)**	2,535	2,036	1,537	987	326	(319)	(1,026)	(1,794)	(2,553)
L	SCRs (7), (8)	721	721	721	721	721	721	721	721	721
M	**Statewide System Margin with SCR (K+L)**	3,256	2,756	2,257	1,707	1,046	401	(306)	(1,074)	(1,833)
N	Operating Reserve	(1,310)	(1,310)	(1,310)	(1,310)	(1,310)	(1,310)	(1,310)	(1,310)	(1,310)
O	**Statewide System Margin with Full Operating Reserve (M+N) (4)**	1,946	1,446	947	397	(264)	(909)	(1,616)	(2,384)	(3,143)

Notes:

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

Figure 52: Summer Statewide System Margin Calculation – Status Quo System

Line	Item	Summer Peak - Expected Summer Weather, Normal Transfer Criteria (MW)								
		2026	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**
A	NYCA Generation (1)	36,865	36,765	36,765	36,765	36,765	36,310	36,310	36,310	36,310
B	NYCA Generation Unavailability (2)	(6,352)	(6,354)	(6,359)	(6,365)	(6,371)	(6,329)	(6,335)	(6,335)	(6,341)
C	Temperature Based Generation Derates	0	0	0	0	0	0	0	0	0
D	External Area Interchanges (3)	1,958	1,669	1,669	1,669	1,669	1,669	1,669	1,669	1,669
E	**Total Resources (A+B+C+D)**	32,470	32,080	32,075	32,069	32,063	31,650	31,644	31,644	31,638
F	Demand Forecast (5)	(31,305)	(31,590)	(31,698)	(31,886)	(32,160)	(32,434)	(32,757)	(33,101)	(33,399)
G	Largest Loss-of-Source Contingency	(1,310)	(1,310)	(1,310)	(1,310)	(1,310)	(1,310)	(1,310)	(1,310)	(1,310)
H	**Total Capability Requirement (F+G)**	(32,615)	(32,900)	(33,008)	(33,196)	(33,470)	(33,744)	(34,067)	(34,411)	(34,709)
I	**Statewide System Margin (E+H)**	(145)	(820)	(933)	(1,127)	(1,407)	(2,094)	(2,423)	(2,767)	(3,071)
J	Higher Demand Impact	(600)	(1,170)	(1,650)	(2,050)	(2,330)	(2,520)	(2,660)	(2,830)	(3,160)
K	**Higher Demand Statewide System Margin (I+J)**	(745)	(1,990)	(2,583)	(3,177)	(3,737)	(4,614)	(5,083)	(5,597)	(6,231)
L	SCRs (6), (7)	804	804	804	804	804	804	804	804	804
M	**Statewide System Margin with SCR (K+L)**	59	(1,186)	(1,780)	(2,373)	(2,933)	(3,810)	(4,279)	(4,793)	(5,427)
N	Operating Reserve	(1,310)	(1,310)	(1,310)	(1,310)	(1,310)	(1,310)	(1,310)	(1,310)	(1,310)
O	**Statewide System Margin with Full Operating Reserve (M+N) (4)**	(1,251)	(2,496)	(3,090)	(3,683)	(4,243)	(5,120)	(5,589)	(6,103)	(6,737)

Notes:

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

Figure 53: Winter Statewide System Margin Calculation – Status Quo System

Line	Item	Winter Peak - Baseline Expected Winter Weather, Normal Transfer Criteria (MW)								
		2026-27	2027-28	2028-29	2029-30	2030-31	2031-32	2032-33	2033-34	2034-35
A	NYCA Generation (1)	38,935	38,818	38,818	38,818	38,360	38,360	38,360	38,360	38,360
B	NYCA Generation Unavailability (2)	(6,161)	(6,149)	(6,149)	(6,149)	(6,150)	(6,150)	(6,150)	(6,150)	(6,150)
C	Unavailability of Non-Firm Gas (6)	(5,823)	(5,823)	(5,823)	(5,823)	(5,365)	(5,365)	(5,365)	(5,365)	(5,365)
D	Temperature Based Generation Derates	0	0	0	0	0	0	0	0	0
E	External Area Interchanges (3)	849	560	560	560	560	560	560	560	560
F	**Total Resources (A+B+C+D+E)**	27,800	27,406	27,406	27,406	27,406	27,406	27,406	27,406	27,406
G	Demand Forecast (5)	(24,920)	(25,316)	(25,815)	(26,365)	(27,026)	(27,671)	(28,378)	(29,146)	(29,905)
H	Large Load Flexibility	685	685	685	685	685	685	685	685	685
I	Largest Loss-of-Source Contingency	(1,310)	(1,310)	(1,310)	(1,310)	(1,310)	(1,310)	(1,310)	(1,310)	(1,310)
J	**Total Capability Requirement (G+H+I)**	(25,545)	(25,941)	(26,440)	(26,990)	(27,651)	(28,296)	(29,003)	(29,771)	(30,530)
K	**Statewide System Margin (F+J)**	2,255	1,465	966	416	(245)	(890)	(1,597)	(2,365)	(3,124)
L	SCRs (7), (8)	721	721	721	721	721	721	721	721	721
M	**Statewide System Margin with SCR (K+L)**	2,975	2,185	1,686	1,136	475	(170)	(877)	(1,645)	(2,404)
N	Operating Reserve	(1,310)	(1,310)	(1,310)	(1,310)	(1,310)	(1,310)	(1,310)	(1,310)	(1,310)
O	**Statewide System Margin with Full Operating Reserve (M+N) (4)**	1,665	875	376	(174)	(835)	(1,480)	(2,187)	(2,955)	(3,714)

Notes:

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

Lower Hudson Valley (Zones G-J)

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

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

Figure 54 and Figure 56 show the calculation of the summer and winter Lower Hudson Valley transmission security margin for baseline expected weather, expected load conditions for the statewide coincident peak hour with normal transfer criteria. As detailed in the body of this report, this STAR finds that the Lower Hudson Valley is deficient beginning in summer 2027 under status quo assumptions. This deficiency is further exacerbated through time without any additional capabilities added to this locality.

Figure 54: Summer Peak Lower Hudson Valley Margin Calculation – Status Quo System

Summer Peak - Expected Weather, Normal Transfer Criteria (MW)										
Line	**Item**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**
A	G-J Demand Forecast	(15,034)	(15,103)	(15,145)	(15,176)	(15,205)	(15,280)	(15,401)	(15,515)	(15,652)
B	RECO Demand	(407)	(407)	(407)	(404)	(404)	(404)	(404)	(404)	(417)
C	**Total Demand (A+B)**	(15,441)	(15,510)	(15,552)	(15,580)	(15,609)	(15,684)	(15,805)	(15,919)	(16,069)
D	UPNY-SENY Limit (3)	4,700	4,700	4,700	4,700	4,700	4,700	4,700	4,700	4,700
E	ABC PARs to J	(11)	(11)	(11)	(11)	(11)	(11)	(11)	(11)	(11)
F	K - SENY	47	(274)	(274)	(298)	(350)	(456)	(508)	(565)	(616)
G	**Total SENY AC Import (D+E+F)**	4,736	4,415	4,415	4,391	4,339	4,233	4,181	4,124	4,073
H	Loss of Source Contingency	0	0	0	0	0	0	0	0	0
I	**Resource Need (C+G+H)**	(10,705)	(11,095)	(11,137)	(11,189)	(11,270)	(11,451)	(11,624)	(11,795)	(11,996)
J	G-J Generation (1)	12,350	12,350	12,350	12,350	12,350	11,941	11,941	11,941	11,941
K	G-J Generation Unavailability (2)	(1,176)	(1,176)	(1,176)	(1,176)	(1,176)	(1,134)	(1,134)	(1,134)	(1,134)
L	Temperature Based Generation Derates	0	0	0	0	0	0	0	0	0
M	Net ICAP External Imports (4)	140	140	140	140	140	140	140	140	140
N	**Total Resources Available (J+K+L+M)**	11,315	11,315	11,315	11,315	11,315	10,947	10,947	10,947	10,947
O	**Transmission Security Margin (I+N)**	610	219	178	126	45	(503)	(677)	(848)	(1,048)
P	Higher Demand Impact	(142)	(236)	(362)	(509)	(684)	(791)	(865)	(971)	(1,067)
Q	**Higher Demand Transmission Security Margin (O+P)**	468	(17)	(184)	(383)	(639)	(1,294)	(1,542)	(1,819)	(2,115)
R	Noncoincident Peak Demand Impact	(246)	(246)	(247)	(247)	(247)	(248)	(250)	(252)	(256)
S	**Noncoincident Peak Transmission Security Margin (O+R)**	364	(27)	(69)	(121)	(202)	(751)	(927)	(1,100)	(1,304)
T	2026 NYCA ICAP Market Peak Forecast Impact	(278)	-	-	-	-	-	-	-	-
U	**2026 NYCA ICAP Market Peak Forecast Margin (O+T)**	332	-	-	-	-	-	-	-	-

Notes:

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

Figure 55: Summer Peak Lower Hudson Valley Margin Calculation – Planned System

Summer Peak - Expected Weather, Normal Transfer Criteria (MW)										
Line	**Item**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**
A	G-J Demand Forecast	(15,034)	(15,103)	(15,145)	(15,176)	(15,205)	(15,280)	(15,401)	(15,515)	(15,652)
B	RECO Demand	(407)	(407)	(407)	(404)	(404)	(404)	(404)	(404)	(417)
C	**Total Demand (A+B)**	(15,441)	(15,510)	(15,552)	(15,580)	(15,609)	(15,684)	(15,805)	(15,919)	(16,069)
D	UPNY-SENY Limit (3)	4,700	4,700	4,700	4,700	4,500	4,500	4,500	4,500	4,500
E	ABC PARs to J	(11)	(11)	(11)	(11)	(11)	(11)	(11)	(11)	(11)
F	K - SENY	47	(169)	(76)	(99)	(152)	(258)	(311)	(368)	(419)
G	**Total SENY AC Import (D+E+F)**	4,736	4,520	4,613	4,590	4,337	4,231	4,178	4,121	4,070
H	Loss of Source Contingency	0	0	0	0	0	0	0	0	0
I	**Resource Need (C+G+H)**	(10,705)	(10,990)	(10,939)	(10,990)	(11,272)	(11,453)	(11,627)	(11,798)	(11,999)
J	G-J Generation (1)	12,380	13,311	13,311	13,311	13,311	12,902	12,902	12,902	12,902
K	G-J Generation Unavailability (2)	(1,200)	(2,050)	(2,051)	(2,051)	(2,051)	(2,009)	(1,891)	(1,892)	(1,892)
L	Temperature Based Generation Derates	0	0	0	0	0	0	0	0	0
M	Net ICAP External Imports (4)	1,390	1,390	1,390	1,390	1,390	1,390	1,390	1,390	1,390
N	**Total Resources Available (J+K+L+M)**	12,570	12,652	12,651	12,651	12,650	12,283	12,401	12,400	12,400
O	**Transmission Security Margin (I+N)**	1,865	1,662	1,712	1,660	1,378	829	774	602	402
P	Higher Demand Impact	(142)	(236)	(362)	(509)	(684)	(791)	(865)	(971)	(1,067)
Q	**Higher Demand Transmission Security Margin (O+P)**	1,723	1,426	1,350	1,151	694	38	(91)	(369)	(665)
R	Noncoincident Peak Demand Impact	(246)	(246)	(247)	(247)	(247)	(248)	(250)	(252)	(256)
S	**Noncoincident Peak Transmission Security Margin (O+R)**	1,619	1,416	1,465	1,413	1,131	581	524	350	146
T	2026 NYCA ICAP Market Peak Forecast Impact	(278)	-	-	-	-	-	-	-	-
U	**2026 NYCA ICAP Market Peak Forecast Margin (O+T)**	1,587	-	-	-	-	-	-	-	-

Notes:

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

Figure 56: Winter Peak Lower Hudson Valley Margin Calculation – Status Quo System

Winter Peak - Expected Weather, Normal Transfer Criteria (MW)										
Line	**Item**	**2026-27**	**2027-28**	**2028-29**	**2029-30**	**2030-31**	**2031-32**	**2032-33**	**2033-34**	**2034-35**
A	G-J Demand Forecast	(10,714)	(10,835)	(11,044)	(11,229)	(11,437)	(11,682)	(11,944)	(12,248)	(12,588)
B	RECO Demand	(246)	(246)	(246)	(236)	(236)	(236)	(236)	(236)	(313)
C	**Total Demand (A+B)**	(10,960)	(11,081)	(11,290)	(11,465)	(11,673)	(11,918)	(12,180)	(12,484)	(12,901)
D	UPNY-SENY Limit (3)	5,300	5,300	5,300	5,300	5,300	5,300	5,300	5,300	5,300
E	ABC PARs to J	(11)	(11)	(11)	(11)	(11)	(11)	(11)	(11)	(11)
F	K - SENY	47	47	47	47	47	47	47	47	47
G	**Total SENY AC Import (D+E+F)**	5,336	5,336	5,336	5,336	5,336	5,336	5,336	5,336	5,336
H	Loss of Source Contingency	(973)	(973)	(973)	(973)	(973)	(973)	(973)	(973)	(973)
I	**Resource Need (C+G+H)**	(6,597)	(6,718)	(6,927)	(7,102)	(7,310)	(7,555)	(7,817)	(8,121)	(8,538)
J	G-J Generation (1)	13,075	13,075	13,075	13,075	12,664	12,664	12,664	12,664	12,664
K	G-J Generation Unavailability (2)	(1,118)	(1,118)	(1,118)	(1,118)	(1,118)	(1,118)	(1,118)	(1,118)	(1,118)
L	Shortage of Gas Fuel Supply (4)	(2,214)	(2,214)	(2,214)	(2,214)	(1,803)	(1,803)	(1,803)	(1,803)	(1,803)
M	Temperature Based Generation Derates	0	0	0	0	0	0	0	0	0
N	Net ICAP External Imports (5)	140	140	140	140	140	140	140	140	140
O	**Total Resources Available (J+K+L+M+N)**	9,883	9,883	9,883	9,883	9,883	9,883	9,883	9,883	9,883
P	**Transmission Security Margin (I+O)**	3,286	3,165	2,956	2,781	2,573	2,328	2,066	1,762	1,345
Q	Higher Demand Impact	(174)	(257)	(385)	(461)	(618)	(854)	(1,097)	(1,494)	(1,737)
R	**Higher Demand Transmission Security Margin (P+Q)**	3,112	2,908	2,571	2,320	1,955	1,474	969	268	(392)
S	Noncoincident Peak Demand Impact	(34)	(35)	(36)	(37)	(37)	(37)	(38)	(40)	(41)
T	**Noncoincident Peak Transmission Security Margin (P+S)**	3,252	3,130	2,920	2,744	2,536	2,291	2,028	1,722	1,304

Notes:

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

Figure 57: Winter Peak Lower Hudson Valley Margin Calculation – Planned System

Winter Peak - Expected Weather, Normal Transfer Criteria (MW)										
Line	**Item**	**2026-27**	**2027-28**	**2028-29**	**2029-30**	**2030-31**	**2031-32**	**2032-33**	**2033-34**	**2034-35**
A	G-J Demand Forecast	(10,714)	(10,835)	(11,044)	(11,229)	(11,437)	(11,682)	(11,944)	(12,248)	(12,588)
B	RECO Demand	(246)	(246)	(246)	(236)	(236)	(236)	(236)	(236)	(313)
C	**Total Demand (A+B)**	(10,960)	(11,081)	(11,290)	(11,465)	(11,673)	(11,918)	(12,180)	(12,484)	(12,901)
D	UPNY-SENY Limit (3)	5,300	5,300	5,300	5,300	5,700	5,700	5,700	5,700	5,700
E	ABC PARs to J	(11)	(11)	(11)	(11)	(11)	(11)	(11)	(11)	(11)
F	K - SENY	47	47	47	47	1,013	1,013	1,013	1,013	1,013
G	**Total SENY AC Import (D+E+F)**	5,336	5,336	5,336	5,336	6,702	6,702	6,702	6,702	6,702
H	Loss of Source Contingency	(973)	(973)	(973)	(973)	(973)	(973)	(973)	(973)	(973)
I	**Resource Need (C+G+H)**	(6,597)	(6,718)	(6,927)	(7,102)	(5,944)	(6,189)	(6,451)	(6,755)	(7,172)
J	G-J Generation (1)	14,036	14,036	14,036	14,036	13,625	13,625	13,625	13,625	13,625
K	G-J Generation Unavailability (2)	(1,916)	(1,916)	(1,916)	(1,916)	(1,916)	(1,916)	(1,916)	(1,916)	(1,916)
L	Shortage of Gas Fuel Supply (4)	(2,214)	(2,214)	(2,214)	(2,214)	(1,803)	(1,803)	(1,803)	(1,803)	(1,803)
M	Temperature Based Generation Derates	0	0	0	0	0	0	0	0	0
N	Net ICAP External Imports (5)	140	140	140	140	140	140	140	140	140
O	**Total Resources Available (J+K+L+M+N)**	10,046	10,046	10,046	10,046	10,046	10,046	10,046	10,046	10,046
P	**Transmission Security Margin (I+O)**	3,449	3,328	3,119	2,944	4,102	3,857	3,595	3,291	2,874
Q	Higher Demand Impact	(174)	(257)	(385)	(461)	(618)	(854)	(1,097)	(1,494)	(1,737)
R	**Higher Demand Transmission Security Margin (P+Q)**	3,275	3,071	2,734	2,483	3,484	3,003	2,498	1,797	1,137
S	Noncoincident Peak Demand Impact	(34)	(35)	(36)	(37)	(37)	(37)	(38)	(40)	(41)
T	**Noncoincident Peak Transmission Security Margin (P+S)**	3,415	3,293	3,083	2,907	4,065	3,820	3,557	3,251	2,833

Notes:

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

New York City (Zone J)

The New York City locality comprises Zone J. Within the Con Edison service territory, the 345 kV transmission system, along with specific portions of the 138 kV transmission system, is designed for the occurrence of two non-simultaneous contingencies and a return to normal (N-1-1-0).[37] Therefore, unlike the Lower Hudson Valley and Long Island localities, the New York City transmission security margin is calculated based on the most limiting N-1-1-0 contingency combination. As the system changes, the limiting contingency combination may also change.

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

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

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

Figure 58: Summer Peak New York City Transmission Security Margin Calculation – Status Quo System

Summer Peak - Baseline Expected Weather, Normal Transfer Criteria (MW)										
Line	**Item**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**
A	**Zone J Demand Forecast**	(10,790)	(10,820)	(10,840)	(10,860)	(10,880)	(10,930)	(11,010)	(11,080)	(11,170)
B	I+K to J (3)	3,900	3,900	3,900	3,900	3,900	3,900	3,900	3,900	3,900
C	ABC PARs to J	(11)	(11)	(11)	(11)	(11)	(11)	(11)	(11)	(11)
D	**Total J AC Import (B+C)**	3,889	3,889	3,889	3,889	3,889	3,889	3,889	3,889	3,889
E	Loss of Source Contingency	(985)	(985)	(985)	(985)	(985)	(985)	(985)	(985)	(985)
F	**Resource Need (A+D+E)**	(7,886)	(7,916)	(7,936)	(7,956)	(7,976)	(8,026)	(8,106)	(8,176)	(8,266)
G	J Generation (1)	8,108	8,108	8,108	8,108	8,108	7,698	7,698	7,698	7,698
H	J Generation Unavailability (2)	(772)	(772)	(772)	(772)	(772)	(730)	(730)	(730)	(730)
I	Temperature Based Generation Derates	0	0	0	0	0	0	0	0	0
J	Net ICAP External Imports (4)	140	140	140	140	140	140	140	140	140
K	**Total Resources Available (G+H+I+J)**	7,476	7,476	7,476	7,476	7,476	7,109	7,109	7,109	7,109
L	**Baseline Transmission Security Margin (F+K)**	(410)	(440)	(460)	(480)	(500)	(917)	(997)	(1,067)	(1,157)
M	Higher Demand Impact	(130)	(220)	(330)	(470)	(630)	(720)	(790)	(880)	(960)
N	**Higher Demand Transmission Security Margin (L+M)**	(540)	(660)	(790)	(950)	(1,130)	(1,637)	(1,787)	(1,947)	(2,117)
O	Noncoincident Peak Demand Impact	(240)	(240)	(240)	(240)	(240)	(240)	(250)	(250)	(250)
P	**Noncoincident Peak Transmission Security Margin (L+O)**	(650)	(680)	(700)	(720)	(740)	(1,157)	(1,247)	(1,317)	(1,407)
Q	2026 NYCA ICAP Market Peak Forecast Impact	(272)	-	-	-	-	-	-	-	-
R	**2026 NYCA ICAP Market Peak Forecast Margin (L+Q)**	(682)	-	-	-	-	-	-	-	-

Notes:

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

Figure 59: Summer Peak New York City Transmission Security Margin Calculation – Planned System

Summer Peak - Expected Weather, Normal Transfer Criteria (MW)										
Line	**Item**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**
A	**Zone J Demand Forecast**	(10,790)	(10,820)	(10,840)	(10,860)	(10,880)	(10,930)	(11,010)	(11,080)	(11,170)
B	I+K to J (3)	4,700	4,700	4,700	4,700	4,800	4,800	4,800	4,800	4,800
C	ABC PARs to J	(11)	(11)	(11)	(11)	(11)	(11)	(11)	(11)	(11)
D	**Total J AC Import (B+C)**	4,689	4,689	4,689	4,689	4,789	4,789	4,789	4,789	4,789
E	Loss of Source Contingency	(2,235)	(2,235)	(2,235)	(2,235)	(2,235)	(2,235)	(2,235)	(2,235)	(2,235)
F	**Resource Need (A+D+E)**	(8,336)	(8,366)	(8,386)	(8,406)	(8,326)	(8,376)	(8,456)	(8,526)	(8,616)
G	J Generation (1)	8,108	9,039	9,039	9,039	9,039	8,629	8,629	8,629	8,629
H	J Generation Unavailability (2)	(772)	(1,621)	(1,621)	(1,589)	(1,621)	(1,579)	(1,579)	(1,579)	(1,579)
I	Temperature Based Generation Derates	0	0	0	0	0	0	0	0	0
J	Net ICAP External Imports (4)	1,390	1,390	1,390	1,390	1,390	1,390	1,390	1,390	1,390
K	**Total Resources Available (G+H+I+J)**	8,726	8,808	8,808	8,840	8,808	8,440	8,440	8,440	8,440
L	**Baseline Transmission Security Margin (F+K)**	390	442	422	433	482	64	(16)	(86)	(176)
M	Higher Demand Impact	(130)	(220)	(330)	(470)	(630)	(720)	(790)	(880)	(960)
N	**Higher Demand Transmission Security Margin (L+M)**	260	222	92	(37)	(148)	(656)	(806)	(966)	(1,136)
O	Noncoincident Peak Demand Impact	(240)	(240)	(240)	(240)	(240)	(240)	(250)	(250)	(250)
P	**Noncoincident Peak Transmission Security Margin (L+O)**	150	202	182	193	242	(176)	(266)	(336)	(426)
Q	2026 NYCA ICAP Market Peak Forecast Impact	(272)	-	-	-	-	-	-	-	-
R	**2026 NYCA ICAP Market Peak Forecast Margin (L+Q)**	118	-	-	-	-	-	-	-	-

Notes:

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

Figure 60: Winter Peak New York City Transmission Security Margin Calculation – Status Quo System

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

Notes:

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

Figure 61: Winter Peak New York City Transmission Security Margin Calculation – Planned System

Winter Peak - Expected Weather, Normal Transfer Criteria (MW)										
Line	**Item**	**2026-27**	**2027-28**	**2028-29**	**2029-30**	**2030-31**	**2031-32**	**2032-33**	**2033-34**	**2034-35**
A	**Zone J Demand Forecast**	(7,580)	(7,650)	(7,800)	(7,930)	(8,070)	(8,240)	(8,410)	(8,610)	(8,830)
B	I+K to J (3)	3,900	3,900	3,900	3,900	4,900	4,900	4,900	4,900	4,900
C	ABC PARs to J	(11)	(11)	(11)	(11)	(11)	(11)	(11)	(11)	(11)
D	**Total J AC Import (B+C)**	3,889	3,889	3,889	3,889	4,889	4,889	4,889	4,889	4,889
E	Loss of Source Contingency	(973)	(973)	(973)	(973)	(1,606)	(1,606)	(1,606)	(1,606)	(1,606)
F	**Resource Need (A+D+E)**	(4,664)	(4,734)	(4,884)	(5,014)	(4,787)	(4,957)	(5,127)	(5,327)	(5,547)
G	J Generation (1)	9,533	9,533	9,533	9,533	9,121	9,121	9,121	9,121	9,121
H	J Generation Unavailability (2)	(1,489)	(1,489)	(1,489)	(1,489)	(1,488)	(1,488)	(1,488)	(1,488)	(1,488)
I	Unavailability of Non-Firm Gas (4)	(2,057)	(2,057)	(2,057)	(2,057)	(1,646)	(1,646)	(1,646)	(1,646)	(1,646)
J	Temperature Based Generation Derates	0	0	0	0	0	0	0	0	0
K	Net ICAP External Imports (5)	140	140	140	140	140	140	140	140	140
L	**Total Resources Available (G+H+I+J+K)**	6,127	6,127	6,127	6,127	6,127	6,127	6,127	6,127	6,127
M	**Transmission Security Margin (F+L)**	1,463	1,393	1,243	1,113	1,340	1,170	1,000	800	580
N	Higher Demand Impact	(160)	(230)	(310)	(390)	(490)	(650)	(810)	(1,080)	(1,220)
O	**Higher Demand Transmission Security Margin (M+N)**	1,303	1,163	933	723	850	520	190	(280)	(640)
P	Noncoincident Peak Demand Impact	(50)	(50)	(50)	(60)	(60)	(60)	(60)	(60)	(60)
Q	**Noncoincident Peak Transmission Security Margin (M+P)**	1,413	1,343	1,193	1,053	1,280	1,110	940	740	520

Notes:

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

3. Limits for 2026 through 2029 are based on the winter peak 2029 representations evaluated in the 2024 RNA. Limits for 2030 through 2034 are based on the winter peak 2034 representations evaluated in the 2024 RNA.
4. Unavailability of non-firm gas is modeled per NYSRC Reliability Rule 154a which became effective May 2024. Includes all gas only units that do not have a firm gas contract.
5. Interchanges are based on ERAG MMWG values and firm transactions. Includes a 175 MW reduction in capacity sales from PJM.

Long Island (Zone K)

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

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

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

Figure 62: Summer Peak Long Island Margin Calculation – Status Quo System

Summer Peak - Expected Weather, Normal Transfer Criteria (MW)										
Line	**Item**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**
A	**Zone K Demand Forecast**	(4,996)	(5,012)	(5,011)	(5,034)	(5,086)	(5,151)	(5,203)	(5,260)	(5,310)
B	I+J to K (3)	900	900	900	900	900	900	900	900	900
C	New England Import (NNC)	0	0	0	0	0	0	0	0	0
D	**Total K AC Import (B+C)**	900	900	900	900	900	900	900	900	900
E	Loss of Source Contingency	(660)	(660)	(660)	(660)	(660)	(660)	(660)	(660)	(660)
F	**Resource Need (A+D+E)**	(4,756)	(4,772)	(4,771)	(4,794)	(4,846)	(4,911)	(4,963)	(5,020)	(5,070)
G	K Generation (1)	5,001	4,901	4,901	4,901	4,901	4,856	4,856	4,856	4,856
H	K Generation Unavailability (2)	(832)	(823)	(823)	(824)	(825)	(820)	(821)	(821)	(821)
I	Temperature Based Generation Derates	0	0	0	0	0	0	0	0	0
J	Net ICAP External Imports (4)	949	660	660	660	660	660	660	660	660
K	**Total Resources Available (G+H+I+J)**	5,117	4,738	4,737	4,736	4,736	4,695	4,695	4,695	4,694
L	**Transmission Security Margin (F+K)**	361	(34)	(34)	(58)	(110)	(216)	(268)	(325)	(376)
M	Higher Demand Impact	(43)	(34)	(30)	(24)	(36)	(47)	(63)	(65)	(110)
N	**Higher Demand Transmission Security Margin (L+M)**	318	(68)	(64)	(82)	(146)	(263)	(331)	(390)	(486)
O	Noncoincident Peak Demand Impact	(76)	(77)	(77)	(78)	(79)	(80)	(81)	(82)	(83)
P	**Noncoincident Peak Transmission Security Margin (L+O)**	285	(111)	(111)	(136)	(189)	(296)	(349)	(407)	(459)
Q	2026 NYCA ICAP Market Peak Forecast Impact	(101)	-	-	-	-	-	-	-	-
R	**2026 NYCA ICAP Market Peak Forecast Margin (L+Q)**	260	-	-	-	-	-	-	-	-

Notes:

1. Reflects the 2025 Gold Book existing summer capacity plus projected additions and deactivations.
2. Reflects the derates for generating resources. For this evaluation land-based wind generation is assumed to have a capability of 5% of the total nameplate, off-shore wind at 10% of the total nameplate, solar generation is based on the ratio of solar PV nameplate capacity (2025 Gold Book Table I-9a) and solar PV peak reductions (2025 Gold Book Table I-9c). Derates for run-of-river hydro are included. Includes derates for thermal resources based on NERC five-year class average EFORd data published October 2023 https://www.nerc.com/pa/RAPA/gads/Pages/Reports.aspx). Also includes a reduction of 200 MW based on the impact of Correlated Derates to DMNC on resources impacted by the Modeling Improvements for "Capacity Accreditation project – Correlated Derates" requirements are reflected in the NYISO ICAP manual and the Market Services Tariff Section 5.

3. Limits for 2026 through 2029 are based on the 2024 LIPA Summer Operating Study. Limits for 2030 through 2034 are based on the 2034-2035W winter peak representations evaluated in the 2024RNA.
4. Interchanges are based on ERAG MMWG values and firm transactions. Includes a 175 MW reduction in capacity sales from PJM. Includes external imports from the Cross-Sound Cable in accordance with planned imports through early 2027, but starting in summer 2027 this import is assumed at 0 MW.

Figure 63: Summer Peak Long Island Margin Calculation – Planned System

Summer Peak - Expected Weather, Normal Transfer Criteria (MW)										
Line	**Item**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**
A	**Zone K Demand Forecast**	(4,996)	(5,012)	(5,011)	(5,034)	(5,086)	(5,151)	(5,203)	(5,260)	(5,310)
B	I+J to K (3)	900	900	900	900	2,200	2,200	2,200	2,200	2,200
C	New England Import (NNC)	0	0	0	0	0	0	0	0	0
D	**Total K AC Import (B+C)**	900	900	900	900	2,200	2,200	2,200	2,200	2,200
E	Loss of Source Contingency	(660)	(660)	(660)	(660)	0	0	0	0	0
F	**Resource Need (A+D+E)**	(4,756)	(4,772)	(4,771)	(4,794)	(2,886)	(2,951)	(3,003)	(3,060)	(3,110)
G	K Generation (1)	5,017	5,017	5,941	5,941	5,941	5,896	5,896	5,896	5,896
H	K Generation Unavailability (2)	(833)	(834)	(1,666)	(1,667)	(1,667)	(1,664)	(1,664)	(1,664)	(1,665)
I	Temperature Based Generation Derates	0	0	0	0	0	0	0	0	0
J	Net ICAP External Imports (4)	949	660	660	660	660	660	660	660	660
K	**Total Resources Available (G+H+I+J)**	5,133	4,843	4,935	4,935	4,934	4,893	4,892	4,892	4,891
L	**Transmission Security Margin (F+K)**	377	71	164	141	2,048	1,942	1,889	1,832	1,781
M	Higher Demand Impact	(43)	(34)	(30)	(24)	(36)	(47)	(63)	(65)	(110)
N	**Higher Demand Transmission Security Margin (L+M)**	334	37	134	117	2,012	1,895	1,826	1,767	1,671
O	Noncoincident Peak Demand Impact	(76)	(77)	(77)	(78)	(79)	(80)	(81)	(82)	(83)
P	**Noncoincident Peak Transmission Security Margin (L+O)**	301	(6)	87	63	1,969	1,862	1,808	1,750	1,698
Q	2026 NYCA ICAP Market Peak Forecast Impact	(101)	-	-	-	-	-	-	-	-
R	**2026 NYCA ICAP Market Peak Forecast Margin (L+Q)**	276	-	-	-	-	-	-	-	-

Notes:

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

Figure 64: Winter Peak Long Island Margin Calculation – Status Quo System

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

Notes:

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

Figure 65: Winter Peak Long Island Margin Calculation – Planned System

Winter Peak - Baseline Weather, Normal Transfer Criteria (MW)										
Line	**Item**	**2026-27**	**2027-28**	**2028-29**	**2029-30**	**2030-31**	**2031-32**	**2032-33**	**2033-34**	**2034-35**
A	**Zone K Demand Forecast**	(3,276)	(3,335)	(3,443)	(3,585)	(3,716)	(3,860)	(3,995)	(4,114)	(4,221)
B	I+J to K (3), (4)	900	900	900	900	2,500	2,500	2,500	2,500	2,500
C	New England Import (NNC)	0	0	0	0	0	0	0	0	0
D	**Total K AC Import (B+C)**	900	900	900	900	2,500	2,500	2,500	2,500	2,500
E	Loss of Source Contingency	(660)	(660)	(660)	(660)	(399)	(399)	(399)	(399)	(399)
F	**Resource Need (A+D+E)**	(3,036)	(3,095)	(3,203)	(3,345)	(1,615)	(1,759)	(1,894)	(2,013)	(2,120)
G	K Generation (1)	5,459	6,383	6,383	6,383	6,337	6,337	6,337	6,337	6,337
H	K Generation Unavailability (2)	(854)	(1,593)	(1,593)	(1,593)	(1,593)	(1,593)	(1,593)	(1,593)	(1,593)
I	Shortage of Gas Fuel Supply (5)	(318)	(318)	(318)	(318)	(272)	(272)	(272)	(272)	(272)
J	Temperature Based Generation Derates	0	0	0	0	0	0	0	0	0
K	Net ICAP External Imports (6)	949	660	660	660	660	660	660	660	660
L	**Total Resources Available (G+H+I+J+K)**	5,235	5,132	5,132	5,132	5,132	5,132	5,132	5,132	5,132
M	**Transmission Security Margin (F+L)**	2,199	2,037	1,929	1,787	3,517	3,373	3,238	3,119	3,012
N	Higher Demand Impact	(20)	(15)	(29)	(88)	(155)	(246)	(348)	(529)	(601)
O	**Higher Demand Transmission Security Margin (M+N)**	2,179	2,022	1,900	1,699	3,362	3,127	2,890	2,590	2,411
P	Noncoincident Peak Demand Impact	(13)	(13)	(14)	(15)	(15)	(16)	(16)	(17)	(17)
Q	**Noncoincident Peak Transmission Security Margin (M+P)**	2,186	2,024	1,915	1,772	3,502	3,357	3,222	3,102	2,995

Notes:

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

Appendix F – Additional Outage Impacts to Margins

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

- Figure 66: AOI - Statewide System Margin
- Figure 67: AOI - Lower Hudson Valley Transmission Security Margin
- Figure 68: AOI - New York City Transmission Security Margin
- Figure 69: AOI - Long Island Transmission Security Margin

Figure 66: AOI - Statewide System Margin

Statewide System Margin												
			Year	2026	2027	2028	2029	2030	2031	2032	2033	2034
Statewide System Margin Summer Peak - Expected Summer Weather, Normal Transfer Criteria (MW) (1)				568	(230)	(683)	(1,297)	(1,876)	(2,773)	(3,262)	(3,776)	(4,430)
Unit Name	Summer DMNC (MW)	NERC 5-Year Class Average De-Rate (MW)	Summer De-Rated Capability (MW)	Transmission Security Margin Considering Impact of Generator Outage (Retire, Mothball, IIFO)								
Jamestown 5, 6 & 7	74.7	(7.90)	66.80	501	(297)	(750)	(1,363)	(1,943)	(2,840)	(3,329)	(3,843)	(4,497)
Jamestown 5	19.0	(2.06)	16.94	551	(247)	(700)	(1,314)	(1,893)	(2,790)	(3,279)	(3,793)	(4,447)
Jamestown 6	16.5	(1.79)	14.71	553	(245)	(698)	(1,311)	(1,891)	(2,788)	(3,277)	(3,791)	(4,444)
Jamestown 7	39.2	(4.05)	35.15	533	(265)	(718)	(1,332)	(1,911)	(2,809)	(3,297)	(3,811)	(4,465)
Indeck-Yerkes	43.1	(2.03)	41.07	527	(271)	(724)	(1,338)	(1,917)	(2,814)	(3,303)	(3,817)	(4,471)
Indeck-Olean	79.0	(3.72)	75.28	493	(305)	(758)	(1,372)	(1,952)	(2,849)	(3,337)	(3,851)	(4,505)
American Ref-Fuel 1 & 2	37.6	(4.08)	33.52	534	(264)	(716)	(1,330)	(1,910)	(2,807)	(3,296)	(3,810)	(4,463)
American Ref-Fuel 1	18.8	(2.04)	16.76	551	(247)	(700)	(1,313)	(1,893)	(2,790)	(3,279)	(3,793)	(4,447)
American Ref-Fuel 2	18.8	(2.04)	16.76	551	(247)	(700)	(1,313)	(1,893)	(2,790)	(3,279)	(3,793)	(4,447)
Fortistar - N.Tonawanda (BTM:NG)	46.5	(2.19)	44.31	524	(274)	(727)	(1,341)	(1,921)	(2,818)	(3,306)	(3,820)	(4,474)
Model City Energy	5.6	(0.74)	4.86	563	(235)	(688)	(1,301)	(1,881)	(2,778)	(3,267)	(3,781)	(4,435)
Modern LF	6.4	(0.84)	5.56	562	(236)	(688)	(1,302)	(1,882)	(2,779)	(3,268)	(3,782)	(4,435)
Chaffee	6.4	(0.84)	5.56	562	(236)	(688)	(1,302)	(1,882)	(2,779)	(3,268)	(3,782)	(4,435)
Chautauqua LFGE	0.0	0.00	0.00	568	(230)	(683)	(1,297)	(1,876)	(2,773)	(3,262)	(3,776)	(4,430)
Lockport CC1, CC2, and CC3	210.0	(9.89)	200.11	368	(430)	(883)	(1,497)	(2,076)	(2,974)	(3,462)	(3,976)	(4,630)
Lockport CC1	70.0	(3.30)	66.70	501	(297)	(750)	(1,363)	(1,943)	(2,840)	(3,329)	(3,843)	(4,496)
Lockport CC2	70.0	(3.30)	66.70	501	(297)	(750)	(1,363)	(1,943)	(2,840)	(3,329)	(3,843)	(4,496)
Lockport CC3	70.0	(3.30)	66.70	501	(297)	(750)	(1,363)	(1,943)	(2,840)	(3,329)	(3,843)	(4,496)
Allegany	62.7	(2.95)	59.75	508	(290)	(743)	(1,356)	(1,936)	(2,833)	(3,322)	(3,836)	(4,490)
R. E. Ginna	578.8	(11.98)	566.82	1	(797)	(1,250)	(1,863)	(2,443)	(3,340)	(3,829)	(4,343)	(4,997)
Batavia	47.5	(2.24)	45.26	523	(275)	(728)	(1,342)	(1,922)	(2,819)	(3,307)	(3,821)	(4,475)
Nine Mile Point 2[2]	1,283.4	(23.10)	1,260.30	(404)	(1,202)	(1,655)	(2,268)	(2,848)	(3,745)	(4,234)	(4,748)	(5,402)
Mill Seat	6.4	(0.84)	5.56	562	(236)	(688)	(1,302)	(1,882)	(2,779)	(3,268)	(3,782)	(4,435)
Hyland LFGE	4.8	(0.63)	4.17	564	(234)	(687)	(1,301)	(1,880)	(2,778)	(3,266)	(3,780)	(4,434)
Synergy Biogas	0.0	0.00	0.00	568	(230)	(683)	(1,297)	(1,876)	(2,773)	(3,262)	(3,776)	(4,430)
Red Rochester (BTM:NG)	16.5	(1.79)	14.71	553	(245)	(698)	(1,311)	(1,891)	(2,788)	(3,277)	(3,791)	(4,444)
James A. FitzPatrick	844.0	(15.19)	828.81	(261)	(1,059)	(1,512)	(2,125)	(2,705)	(3,602)	(4,091)	(4,605)	(5,259)
Oswego 6	791.7	(85.90)	705.80	(138)	(936)	(1,389)	(2,002)	(2,582)	(3,479)	(3,968)	(4,482)	(5,136)
Oswego 5	820.5	(89.02)	731.48	(163)	(962)	(1,414)	(2,028)	(2,608)	(3,505)	(3,994)	(4,508)	(5,161)
Nine Mile Point 1	619.7	(11.15)	608.55	(41)	(839)	(1,291)	(1,905)	(2,485)	(3,382)	(3,871)	(4,385)	(5,038)
Independence GS1, GS2, GS3, & GS4	996.4	(46.93)	949.47	(381)	(1,180)	(1,632)	(2,246)	(2,826)	(3,723)	(4,212)	(4,726)	(5,379)

Statewide System Margin												
			Year	2026	2027	2028	2029	2030	2031	2032	2033	2034
Statewide System Margin Summer Peak - Expected Summer Weather, Normal Transfer Criteria (MW) (1)				568	(230)	(683)	(1,297)	(1,876)	(2,773)	(3,262)	(3,776)	(4,430)
Unit Name	Summer DMNC (MW)	NERC 5-Year Class Average De-Rate (MW)	Summer De-Rated Capability (MW)	Transmission Security Margin Considering Impact of Generator Outage (Retire, Mothball, IIFO)								
Independence GS1	249.1	(11.73)	237.37	331	(467)	(920)	(1,534)	(2,114)	(3,011)	(3,499)	(4,013)	(4,667)
Independence GS2	249.1	(11.73)	237.37	331	(467)	(920)	(1,534)	(2,114)	(3,011)	(3,499)	(4,013)	(4,667)
Independence GS3	249.1	(11.73)	237.37	331	(467)	(920)	(1,534)	(2,114)	(3,011)	(3,499)	(4,013)	(4,667)
Independence GS4	249.1	(11.73)	237.37	331	(467)	(920)	(1,534)	(2,114)	(3,011)	(3,499)	(4,013)	(4,667)
Syracuse	86.2	(4.06)	82.14	486	(312)	(765)	(1,379)	(1,958)	(2,856)	(3,344)	(3,858)	(4,512)
Carr St.-E. Syr	89.6	(4.22)	85.38	483	(315)	(768)	(1,382)	(1,962)	(2,859)	(3,347)	(3,861)	(4,515)
Indeck-Oswego	51.9	(2.44)	49.46	519	(280)	(732)	(1,346)	(1,926)	(2,823)	(3,312)	(3,826)	(4,479)
Indeck-Silver Springs	52.7	(2.48)	50.22	518	(280)	(733)	(1,347)	(1,926)	(2,824)	(3,312)	(3,826)	(4,480)
Greenidge 4 (BTM:NG)	29.8	(3.23)	26.57	541	(1,047)	169	(36)	(240)	(494)	(834)	(1,328)	(1,823)
Ontario LFGE	11.2	(1.48)	9.72	558	(240)	(693)	(1,306)	(1,886)	(2,783)	(3,272)	(3,786)	(4,439)
High Acres	9.6	(1.27)	8.33	560	(238)	(691)	(1,305)	(1,885)	(2,782)	(3,270)	(3,784)	(4,438)
Seneca Energy 1 & 2	17.6	(2.32)	15.28	553	(245)	(698)	(1,312)	(1,892)	(2,789)	(3,277)	(3,791)	(4,445)
Seneca Energy 1	8.8	(1.16)	7.64	560	(238)	(691)	(1,304)	(1,884)	(2,781)	(3,270)	(3,784)	(4,437)
Seneca Energy 2	8.8	(1.16)	7.64	560	(238)	(691)	(1,304)	(1,884)	(2,781)	(3,270)	(3,784)	(4,437)
Broome LFGE	2.4	(0.32)	2.08	566	(232)	(685)	(1,299)	(1,878)	(2,776)	(3,264)	(3,778)	(4,432)
Massena	79.5	(3.74)	75.76	492	(306)	(759)	(1,372)	(1,952)	(2,849)	(3,338)	(3,852)	(4,506)
Clinton LFGE	6.4	(0.84)	5.56	562	(236)	(688)	(1,302)	(1,882)	(2,779)	(3,268)	(3,782)	(4,435)
Saranac Energy CC1 & CC2	239.4	(11.28)	228.12	340	(458)	(911)	(1,525)	(2,104)	(3,002)	(3,490)	(4,004)	(4,658)
Saranac Energy CC1	122.1	(5.75)	116.35	452	(346)	(799)	(1,413)	(1,993)	(2,890)	(3,378)	(3,892)	(4,546)
Saranac Energy CC2	117.3	(5.52)	111.78	456	(342)	(795)	(1,408)	(1,988)	(2,885)	(3,374)	(3,888)	(4,542)
Sterling	48.4	(2.28)	46.12	522	(276)	(729)	(1,343)	(1,922)	(2,820)	(3,308)	(3,822)	(4,476)
Carthage Energy	52.8	(2.49)	50.31	518	(280)	(733)	(1,347)	(1,927)	(2,824)	(3,312)	(3,826)	(4,480)
Beaver Falls	79.7	(3.75)	75.95	492	(306)	(759)	(1,373)	(1,952)	(2,849)	(3,338)	(3,852)	(4,506)
Broome 2 LFGE	2.1	(0.28)	1.82	566	(232)	(685)	(1,298)	(1,878)	(2,775)	(3,264)	(3,778)	(4,432)
DANC LFGE	6.4	(0.84)	5.56	562	(236)	(688)	(1,302)	(1,882)	(2,779)	(3,268)	(3,782)	(4,435)
Oneida-Herkimer LFGE	3.2	(0.42)	2.78	565	(233)	(686)	(1,299)	(1,879)	(2,776)	(3,265)	(3,779)	(4,433)
Athens 1, 2, and 3	947.7	(44.64)	903.06	(335)	(1,133)	(1,586)	(2,200)	(2,779)	(3,676)	(4,165)	(4,679)	(5,333)
Athens 1	329.4	(15.51)	313.89	254	(544)	(997)	(1,610)	(2,190)	(3,087)	(3,576)	(4,090)	(4,744)
Athens 2	333.3	(15.70)	317.60	250	(548)	(1,001)	(1,614)	(2,194)	(3,091)	(3,580)	(4,094)	(4,747)
Athens 3	285.0	(13.42)	271.58	296	(502)	(955)	(1,568)	(2,148)	(3,045)	(3,534)	(4,048)	(4,701)
Rensselaer	76.8	(3.62)	73.18	495	(303)	(756)	(1,370)	(1,949)	(2,847)	(3,335)	(3,849)	(4,503)

Statewide System Margin												
			Year	2026	2027	2028	2029	2030	2031	2032	2033	2034
Statewide System Margin Summer Peak - Expected Summer Weather, Normal Transfer Criteria (MW) (1)				568	(230)	(683)	(1,297)	(1,876)	(2,773)	(3,262)	(3,776)	(4,430)
Unit Name	Summer DMNC (MW)	NERC 5-Year Class Average De-Rate (MW)	Summer De-Rated Capability (MW)	Transmission Security Margin Considering Impact of Generator Outage (Retire, Mothball, IIFO)								
Wheelabrator Hudson Falls	10.4	(1.13)	9.27	559	(239)	(692)	(1,306)	(1,886)	(2,783)	(3,271)	(3,785)	(4,439)
Selkirk I & II	353.0	(16.63)	336.37	232	(566)	(1,019)	(1,633)	(2,213)	(3,110)	(3,598)	(4,112)	(4,766)
Selkirk-I	76.4	(3.60)	72.80	495	(303)	(756)	(1,369)	(1,949)	(2,846)	(3,335)	(3,849)	(4,503)
Selkirk-II	276.6	(13.03)	263.57	304	(494)	(947)	(1,560)	(2,140)	(3,037)	(3,526)	(4,040)	(4,693)
Indeck-Corinth	128.5	(6.05)	122.45	446	(353)	(805)	(1,419)	(1,999)	(2,896)	(3,385)	(3,899)	(4,552)
Castleton Energy Center	67.0	(3.16)	63.84	504	(294)	(747)	(1,360)	(1,940)	(2,837)	(3,326)	(3,840)	(4,494)
Bethlehem GS1, GS2, GS3	817.2	(38.49)	778.71	(211)	(1,009)	(1,462)	(2,075)	(2,655)	(3,552)	(4,041)	(4,555)	(5,208)
Bethlehem GS1	272.4	(12.83)	259.57	308	(490)	(943)	(1,556)	(2,136)	(3,033)	(3,522)	(4,036)	(4,689)
Bethlehem GS2	272.4	(12.83)	259.57	308	(490)	(943)	(1,556)	(2,136)	(3,033)	(3,522)	(4,036)	(4,689)
Bethlehem GS3	272.4	(12.83)	259.57	308	(490)	(943)	(1,556)	(2,136)	(3,033)	(3,522)	(4,036)	(4,689)
Colonie LFGTE	6.4	(0.84)	5.56	562	(236)	(688)	(1,302)	(1,882)	(2,779)	(3,268)	(3,782)	(4,435)
Albany LFGE	5.6	(0.74)	4.86	563	(235)	(688)	(1,301)	(1,881)	(2,778)	(3,267)	(3,781)	(4,435)
Fulton LFGE	3.2	(0.42)	2.78	565	(233)	(686)	(1,299)	(1,879)	(2,776)	(3,265)	(3,779)	(4,433)
Empire CC1 & CC2	591.6	(27.86)	563.74	4	(794)	(1,247)	(1,860)	(2,440)	(3,337)	(3,826)	(4,340)	(4,993)
Empire CC1	295.8	(13.93)	281.87	286	(512)	(965)	(1,578)	(2,158)	(3,055)	(3,544)	(4,058)	(4,712)
Empire CC2	295.8	(13.93)	281.87	286	(512)	(965)	(1,578)	(2,158)	(3,055)	(3,544)	(4,058)	(4,712)
Bowline 1 & 2	1,136.3	(123.29)	1,013.01	(445)	(1,243)	(1,696)	(2,310)	(2,889)	(3,786)	(4,275)	(4,789)	(5,443)
Bowline 1	565.1	(61.31)	503.79	64	(734)	(1,187)	(1,800)	(2,380)	(3,277)	(3,766)	(4,280)	(4,934)
Bowline 2	571.2	(61.98)	509.22	59	(739)	(1,192)	(1,806)	(2,385)	(3,283)	(3,771)	(4,285)	(4,939)
Danskammer 1, 2, 3, & 4[3]	-	-	-	-	-	-	-	-	-	-	-	-
Danskammer 1[3]	-	-	-	-	-	-	-	-	-	-	-	-
Danskammer 2[3]	-	-	-	-	-	-	-	-	-	-	-	-
Danskammer 3[3]	-	-	-	-	-	-	-	-	-	-	-	-
Danskammer 4[3]	-	-	-	-	-	-	-	-	-	-	-	-
Roseton 1 & 2	1,224.1	(132.81)	1,091.29	(523)	(1,321)	(1,774)	(2,388)	(2,968)	(3,865)	(4,353)	(4,867)	(5,521)
Roseton 1	616.8	(66.92)	549.88	18	(780)	(1,233)	(1,846)	(2,426)	(3,323)	(3,812)	(4,326)	(4,980)
Roseton 2	607.3	(65.89)	541.41	27	(771)	(1,224)	(1,838)	(2,418)	(3,315)	(3,804)	(4,318)	(4,971)
Hillburn GT	34.7	(3.14)	31.56	536	(262)	(715)	(1,328)	(1,908)	(2,805)	(3,294)	(3,808)	(4,461)
Shoemaker GT	32.3	(2.92)	29.38	539	(259)	(712)	(1,326)	(1,906)	(2,803)	(3,291)	(3,805)	(4,459)
DCRRA	6.3	(0.68)	5.62	562	(236)	(689)	(1,302)	(1,882)	(2,779)	(3,268)	(3,782)	(4,435)
CPV Valley CC1 & CC2	649.8	(30.61)	619.19	(51)	(849)	(1,302)	(1,916)	(2,495)	(3,393)	(3,881)	(4,395)	(5,049)
CPV Valley CC1	320.4	(15.09)	305.31	263	(535)	(988)	(1,602)	(2,182)	(3,079)	(3,567)	(4,081)	(4,735)
CPV Valley CC2	329.4	(15.51)	313.89	254	(544)	(997)	(1,610)	(2,190)	(3,087)	(3,576)	(4,090)	(4,744)

Statewide System Margin												
			Year	2026	2027	2028	2029	2030	2031	2032	2033	2034
Statewide System Margin Summer Peak - Expected Summer Weather, Normal Transfer Criteria (MW) (1)				568	(230)	(683)	(1,297)	(1,876)	(2,773)	(3,262)	(3,776)	(4,430)
Unit Name	Summer DMNC (MW)	NERC 5-Year Class Average De-Rate (MW)	Summer De-Rated Capability (MW)	Transmission Security Margin Considering Impact of Generator Outage (Retire, Mothball, IIFO)								
Cricket Valley CC1, CC2, & CC3	1,021.6	(48.12)	973.48	(405)	(1,204)	(1,656)	(2,270)	(2,850)	(3,747)	(4,236)	(4,750)	(5,403)
Cricket Valley CC1	349.7	(16.47)	333.23	235	(563)	(1,016)	(1,630)	(2,209)	(3,107)	(3,595)	(4,109)	(4,763)
Cricket Valley CC2	345.5	(16.27)	329.23	239	(559)	(1,012)	(1,626)	(2,205)	(3,103)	(3,591)	(4,105)	(4,759)
Cricket Valley CC3	326.4	(15.37)	311.03	257	(541)	(994)	(1,608)	(2,187)	(3,084)	(3,573)	(4,087)	(4,741)
Wheelabrator Westchester	53.5	(5.80)	47.70	520	(278)	(731)	(1,344)	(1,924)	(2,821)	(3,310)	(3,824)	(4,477)
Arthur Kill ST 2 & 3	883.6	(95.87)	787.73	(220)	(1,018)	(1,471)	(2,084)	(2,664)	(3,561)	(4,050)	(4,564)	(5,217)
Arthur Kill ST 2	363.2	(39.41)	323.79	244	(554)	(1,007)	(1,620)	(2,200)	(3,097)	(3,586)	(4,100)	(4,754)
Arthur Kill ST 3	520.4	(56.46)	463.94	104	(694)	(1,147)	(1,761)	(2,340)	(3,237)	(3,726)	(4,240)	(4,894)
Brooklyn Navy Yard	249.2	(11.74)	237.46	331	(468)	(920)	(1,534)	(2,114)	(3,011)	(3,500)	(4,014)	(4,667)
Astoria 2, 3, & 5	902.3	(97.90)	804.40	(236)	(1,034)	(1,487)	(2,101)	(2,681)	(3,578)	(4,066)	(4,580)	(5,234)
Astoria 2	158.0	(17.14)	140.86	427	(371)	(824)	(1,437)	(2,017)	(2,914)	(3,403)	(3,917)	(4,571)
Astoria 3	371.1	(40.26)	330.84	237	(561)	(1,014)	(1,627)	(2,207)	(3,104)	(3,593)	(4,107)	(4,761)
Astoria 5	373.2	(40.49)	332.71	235	(563)	(1,016)	(1,629)	(2,209)	(3,106)	(3,595)	(4,109)	(4,762)
Ravenswood ST 01, 02, & 03	1,724.8	(187.14)	1,537.66	(970)	(1,768)	(2,221)	(2,834)	(3,414)	(4,311)	(4,800)	(5,314)	(5,967)
Ravenswood ST 01	364.5	(39.55)	324.95	243	(555)	(1,008)	(1,622)	(2,201)	(3,098)	(3,587)	(4,101)	(4,755)
Ravenswood ST 02	375.2	(40.71)	334.49	234	(565)	(1,017)	(1,631)	(2,211)	(3,108)	(3,597)	(4,111)	(4,764)
Ravenswood ST 03	985.1	(106.88)	878.22	(310)	(1,108)	(1,561)	(2,175)	(2,754)	(3,652)	(4,140)	(4,654)	(5,308)
Ravenswood CC 04	222.2	(10.47)	211.73	356	(442)	(895)	(1,508)	(2,088)	(2,985)	(3,474)	(3,988)	(4,641)
East River 1, 2, 6, & 7	630.7	(49.54)	581.16	(13)	(811)	(1,264)	(1,878)	(2,457)	(3,355)	(3,843)	(4,357)	(5,011)
East River 1	153.2	(7.22)	145.98	422	(376)	(829)	(1,443)	(2,022)	(2,919)	(3,408)	(3,922)	(4,576)
East River 2	154.5	(7.28)	147.22	421	(377)	(830)	(1,444)	(2,023)	(2,921)	(3,409)	(3,923)	(4,577)
East River 6	141.5	(15.35)	126.15	442	(356)	(809)	(1,423)	(2,002)	(2,900)	(3,388)	(3,902)	(4,556)
East River 7	181.5	(19.69)	161.81	406	(392)	(845)	(1,458)	(2,038)	(2,935)	(3,424)	(3,938)	(4,592)
Linden Cogen	748.2	(35.24)	712.96	(145)	(943)	(1,396)	(2,010)	(2,589)	(3,486)	(3,975)	(4,489)	(5,143)
KIAC_JFK (BTM:NG)	105.4	(4.96)	100.44	468	(331)	(783)	(1,397)	(1,977)	(2,874)	(3,363)	(3,877)	(4,530)
Gowanus 5 & 6[4]	79.9	(8.25)	71.65	496	(302)	(755)	(1,368)	(1,948)	-	-	-	-
Gowanus 5[4]	40.0	(4.13)	35.87	532	(266)	(719)	(1,332)	(1,912)	-	-	-	-
Gowanus 6[4]	39.9	(4.12)	35.78	532	(266)	(719)	(1,332)	(1,912)	-	-	-	-
Kent[4]	46.0	(4.75)	41.25	527	(271)	(724)	(1,338)	(1,918)	-	-	-	-
Pouch[4]	44.7	(4.61)	40.09	528	(270)	(723)	(1,337)	(1,916)	-	-	-	-
Hellgate 1 & 2[4]	79.5	(8.20)	71.30	497	(301)	(754)	(1,368)	(1,948)	-	-	-	-
Hellgate 1[4]	39.9	(4.12)	35.78	532	(266)	(719)	(1,332)	(1,912)	-	-	-	-
Hellgate 2[4]	39.6	(4.09)	35.51	532	(266)	(718)	(1,332)	(1,912)	-	-	-	-

Statewide System Margin												
			Year	2026	2027	2028	2029	2030	2031	2032	2033	2034
Statewide System Margin Summer Peak - Expected Summer Weather, Normal Transfer Criteria (MW) (1)				568	(230)	(683)	(1,297)	(1,876)	(2,773)	(3,262)	(3,776)	(4,430)
Unit Name	Summer DMNC (MW)	NERC 5-Year Class Average De-Rate (MW)	Summer De-Rated Capability (MW)	Transmission Security Margin Considering Impact of Generator Outage (Retire, Mothball, IIFO)								
Harlem River 1 & 2[4]	79.5	(8.20)	71.30	497	(301)	(754)	(1,368)	(1,948)	-	-	-	-
Harlem River 1[4]	39.9	(4.12)	35.78	532	(266)	(719)	(1,332)	(1,912)	-	-	-	-
Harlem River 2[4]	39.6	(4.09)	35.51	532	(266)	(718)	(1,332)	(1,912)	-	-	-	-
Vernon Blvd 2 & 3[4]	79.9	(8.25)	71.65	496	(302)	(755)	(1,368)	(1,948)	-	-	-	-
Vernon Blvd 2[4]	40.0	(4.13)	35.87	532	(266)	(719)	(1,332)	(1,912)	-	-	-	-
Vernon Blvd 3[4]	39.9	(4.12)	35.78	532	(266)	(719)	(1,332)	(1,912)	-	-	-	-
Astoria CC 1 & 2	474.0	(22.33)	451.67	116	(682)	(1,135)	(1,748)	(2,328)	(3,225)	(3,714)	(4,228)	(4,881)
Astoria CC 1	237.0	(11.16)	225.84	342	(456)	(909)	(1,522)	(2,102)	(2,999)	(3,488)	(4,002)	(4,656)
Astoria CC 2	237.0	(11.16)	225.84	342	(456)	(909)	(1,522)	(2,102)	(2,999)	(3,488)	(4,002)	(4,656)
Astoria East Energy CC1 & CC2	582.8	(27.45)	555.35	13	(785)	(1,238)	(1,852)	(2,432)	(3,329)	(3,817)	(4,331)	(4,985)
Astoria East Energy - CC1	291.4	(13.72)	277.68	290	(508)	(961)	(1,574)	(2,154)	(3,051)	(3,540)	(4,054)	(4,707)
Astoria East Energy - CC2	291.4	(13.72)	277.68	290	(508)	(961)	(1,574)	(2,154)	(3,051)	(3,540)	(4,054)	(4,707)
Astoria Energy 2 - CC3 & CC4	570.3	(26.86)	543.44	25	(774)	(1,226)	(1,840)	(2,420)	(3,317)	(3,806)	(4,320)	(4,973)
Astoria Energy 2 - CC3	285.0	(13.42)	271.58	296	(502)	(955)	(1,568)	(2,148)	(3,045)	(3,534)	(4,048)	(4,701)
Astoria Energy 2 - CC4	285.3	(13.44)	271.86	296	(502)	(955)	(1,568)	(2,148)	(3,045)	(3,534)	(4,048)	(4,702)
Bayonne EC CT G1 through G10	604.8	(54.67)	550.13	18	(780)	(1,233)	(1,847)	(2,426)	(3,324)	(3,812)	(4,326)	(4,980)
Bayonne EC CTG1	62.0	(5.60)	56.40	512	(286)	(739)	(1,353)	(1,933)	(2,830)	(3,318)	(3,832)	(4,486)
Bayonne EC CTG2	58.0	(5.24)	52.76	515	(283)	(736)	(1,349)	(1,929)	(2,826)	(3,315)	(3,829)	(4,483)
Bayonne EC CTG3	58.1	(5.25)	52.85	515	(283)	(736)	(1,349)	(1,929)	(2,826)	(3,315)	(3,829)	(4,483)
Bayonne EC CTG4	61.1	(5.52)	55.58	512	(286)	(739)	(1,352)	(1,932)	(2,829)	(3,318)	(3,832)	(4,485)
Bayonne EC CTG5	61.8	(5.59)	56.21	512	(286)	(739)	(1,353)	(1,932)	(2,830)	(3,318)	(3,832)	(4,486)
Bayonne EC CTG6	61.4	(5.55)	55.85	512	(286)	(739)	(1,352)	(1,932)	(2,829)	(3,318)	(3,832)	(4,486)
Bayonne EC CTG7	59.7	(5.40)	54.30	514	(284)	(737)	(1,351)	(1,931)	(2,828)	(3,316)	(3,830)	(4,484)
Bayonne EC CTG8	60.0	(5.42)	54.58	513	(285)	(738)	(1,351)	(1,931)	(2,828)	(3,317)	(3,831)	(4,484)
Bayonne EC CTG9	61.3	(5.54)	55.76	512	(286)	(739)	(1,352)	(1,932)	(2,829)	(3,318)	(3,832)	(4,486)
Bayonne EC CTG10	61.4	(5.55)	55.85	512	(286)	(739)	(1,352)	(1,932)	(2,829)	(3,318)	(3,832)	(4,486)
Greenport IC 4, 5, & 6	5.6	(0.83)	4.77	563	(235)	(688)	(1,301)	(1,881)	(2,778)	(3,267)	(3,781)	(4,435)
Greenport IC 4	1.0	(0.15)	0.85	567	(231)	(684)	(1,297)	(1,877)	(2,774)	(3,263)	(3,777)	(4,431)
Greenport IC 5	1.5	(0.22)	1.28	567	(231)	(684)	(1,298)	(1,878)	(2,775)	(3,263)	(3,777)	(4,431)
Greenport IC 6	3.1	(0.46)	2.64	565	(233)	(686)	(1,299)	(1,879)	(2,776)	(3,265)	(3,779)	(4,432)
Freeport 1-2, 1-3, & 2-3	19.2	(2.21)	16.99	551	(247)	(700)	(1,314)	(1,893)	(2,790)	(3,279)	(3,793)	(4,447)
Freeport 1-2	2.3	(0.34)	1.96	566	(232)	(685)	(1,299)	(1,878)	(2,775)	(3,264)	(3,778)	(4,432)
Freeport 1-3	2.7	(0.40)	2.30	566	(232)	(685)	(1,299)	(1,879)	(2,776)	(3,264)	(3,778)	(4,432)

Statewide System Margin												
			Year	2026	2027	2028	2029	2030	2031	2032	2033	2034
Statewide System Margin Summer Peak - Expected Summer Weather, Normal Transfer Criteria (MW) (1)				568	(230)	(683)	(1,297)	(1,876)	(2,773)	(3,262)	(3,776)	(4,430)
Unit Name	Summer DMNC (MW)	NERC 5-Year Class Average De-Rate (MW)	Summer De-Rated Capability (MW)	Transmission Security Margin Considering Impact of Generator Outage (Retire, Mothball, IIFO)								
Freeport 2-3	14.2	(1.47)	12.73	555	(243)	(696)	(1,309)	(1,889)	(2,786)	(3,275)	(3,789)	(4,442)
Charles P Killer 09 through 14	13.5	(1.78)	11.72	556	(242)	(695)	(1,308)	(1,888)	(2,785)	(3,274)	(3,788)	(4,441)
Charles P Keller 09	1.6	(0.21)	1.39	567	(231)	(684)	(1,298)	(1,878)	(2,775)	(3,263)	(3,777)	(4,431)
Charles P Keller 10	1.6	(0.21)	1.39	567	(231)	(684)	(1,298)	(1,878)	(2,775)	(3,263)	(3,777)	(4,431)
Charles P Keller 11	2.4	(0.32)	2.08	566	(232)	(685)	(1,299)	(1,878)	(2,776)	(3,264)	(3,778)	(4,432)
Charles P Keller 12	2.5	(0.33)	2.17	566	(232)	(685)	(1,299)	(1,878)	(2,776)	(3,264)	(3,778)	(4,432)
Charles P Keller 13	2.5	(0.33)	2.17	566	(232)	(685)	(1,299)	(1,878)	(2,776)	(3,264)	(3,778)	(4,432)
Charles P Keller 14	2.9	(0.38)	2.52	565	(233)	(685)	(1,299)	(1,879)	(2,776)	(3,265)	(3,779)	(4,432)
Wading River 1, 2, & 3	214.8	(22.17)	192.63	375	(423)	(876)	(1,489)	(2,069)	(2,966)	(3,455)	(3,969)	(4,622)
Wading River 1	77.6	(8.01)	69.59	498	(300)	(753)	(1,366)	(1,946)	(2,843)	(3,332)	(3,846)	(4,499)
Wading River 2	64.3	(6.64)	57.66	510	(288)	(741)	(1,354)	(1,934)	(2,831)	(3,320)	(3,834)	(4,487)
Wading River 3	72.9	(7.52)	65.38	503	(295)	(748)	(1,362)	(1,942)	(2,839)	(3,327)	(3,841)	(4,495)
Barrett ST 01 & 02	380.5	(41.28)	339.22	229	(569)	(1,022)	(1,636)	(2,215)	(3,113)	(3,601)	(4,115)	(4,769)
Barrett ST 01	192.0	(20.83)	171.17	397	(401)	(854)	(1,468)	(2,047)	(2,945)	(3,433)	(3,947)	(4,601)
Barrett ST 02	188.5	(20.45)	168.05	400	(398)	(851)	(1,465)	(2,044)	(2,941)	(3,430)	(3,944)	(4,598)
Barrett GT 01 through 12	246.6	(23.47)	223.13	345	(453)	(906)	(1,520)	(2,099)	(2,997)	(3,485)	(3,999)	(4,653)
Barrett GT 01	13.7	(1.41)	12.29	556	(242)	(695)	(1,309)	(1,889)	(2,786)	(3,274)	(3,788)	(4,442)
Barrett GT 02	13.6	(1.40)	12.20	556	(242)	(695)	(1,309)	(1,888)	(2,786)	(3,274)	(3,788)	(4,442)
Barrett 03	12.2	(1.26)	10.94	557	(241)	(694)	(1,308)	(1,887)	(2,784)	(3,273)	(3,787)	(4,441)
Barrett 04	14.5	(1.50)	13.00	555	(243)	(696)	(1,310)	(1,889)	(2,786)	(3,275)	(3,789)	(4,443)
Barrett 05	12.0	(1.24)	10.76	557	(241)	(694)	(1,307)	(1,887)	(2,784)	(3,273)	(3,787)	(4,441)
Barrett 06	12.9	(1.33)	11.57	556	(242)	(695)	(1,308)	(1,888)	(2,785)	(3,274)	(3,788)	(4,441)
Barrett 08	12.8	(1.32)	11.48	557	(242)	(694)	(1,308)	(1,888)	(2,785)	(3,274)	(3,788)	(4,441)
Barrett 09	38.6	(3.49)	35.11	533	(265)	(718)	(1,332)	(1,911)	(2,809)	(3,297)	(3,811)	(4,465)
Barrett 10	39.2	(3.54)	35.66	532	(266)	(719)	(1,332)	(1,912)	(2,809)	(3,298)	(3,812)	(4,465)
Barrett 11	38.2	(3.45)	34.75	533	(265)	(718)	(1,331)	(1,911)	(2,808)	(3,297)	(3,811)	(4,465)
Barrett 12	38.9	(3.52)	35.38	533	(265)	(718)	(1,332)	(1,912)	(2,809)	(3,297)	(3,811)	(4,465)
Northport 1, 2, 3, and 4	1,582.2	(171.67)	1,410.53	(843)	(1,641)	(2,093)	(2,707)	(3,287)	(4,184)	(4,673)	(5,187)	(5,840)
Northport 1	399.0	(43.29)	355.71	212	(586)	(1,039)	(1,652)	(2,232)	(3,129)	(3,618)	(4,132)	(4,785)
Northport 2	399.0	(43.29)	355.71	212	(586)	(1,039)	(1,652)	(2,232)	(3,129)	(3,618)	(4,132)	(4,785)
Northport 3	386.2	(41.90)	344.30	224	(574)	(1,027)	(1,641)	(2,221)	(3,118)	(3,606)	(4,120)	(4,774)
Northport 4	398.0	(43.18)	354.82	213	(585)	(1,038)	(1,651)	(2,231)	(3,128)	(3,617)	(4,131)	(4,785)
Port Jefferson GT 02 & 03	79.3	(8.18)	71.12	497	(301)	(754)	(1,368)	(1,947)	(2,845)	(3,333)	(3,847)	(4,501)
Port Jefferson GT 02	39.1	(4.04)	35.06	533	(265)	(718)	(1,332)	(1,911)	(2,808)	(3,297)	(3,811)	(4,465)

Statewide System Margin												
			Year	2026	2027	2028	2029	2030	2031	2032	2033	2034
Statewide System Margin Summer Peak - Expected Summer Weather, Normal Transfer Criteria (MW) (1)				568	(230)	(683)	(1,297)	(1,876)	(2,773)	(3,262)	(3,776)	(4,430)
Unit Name	Summer DMNC (MW)	NERC 5-Year Class Average De-Rate (MW)	Summer De-Rated Capability (MW)	Transmission Security Margin Considering Impact of Generator Outage (Retire, Mothball, IIFO)								
Port Jefferson GT 03	40.2	(4.15)	36.05	532	(266)	(719)	(1,333)	(1,912)	(2,809)	(3,298)	(3,812)	(4,466)
Port Jefferson 3 & 4	380.0	(41.23)	338.77	229	(569)	(1,022)	(1,635)	(2,215)	(3,112)	(3,601)	(4,115)	(4,769)
Port Jefferson 3	191.0	(20.72)	170.28	398	(400)	(853)	(1,467)	(2,047)	(2,944)	(3,432)	(3,946)	(4,600)
Port Jefferson 4	189.0	(20.51)	168.49	400	(399)	(851)	(1,465)	(2,045)	(2,942)	(3,431)	(3,945)	(4,598)
Hempstead (RR)	74.2	(8.05)	66.15	502	(296)	(749)	(1,363)	(1,942)	(2,840)	(3,328)	(3,842)	(4,496)
Glenwood GT 02, 04, & 05	123.9	(12.79)	111.11	457	(341)	(794)	(1,408)	(1,987)	(2,885)	(3,373)	(3,887)	(4,541)
Glenwood GT 02	40.3	(4.16)	36.14	532	(266)	(719)	(1,333)	(1,912)	(2,810)	(3,298)	(3,812)	(4,466)
Glenwood GT 04	41.9	(4.32)	37.58	530	(268)	(721)	(1,334)	(1,914)	(2,811)	(3,300)	(3,814)	(4,467)
Glenwood GT 05	41.7	(4.30)	37.40	531	(267)	(720)	(1,334)	(1,914)	(2,811)	(3,299)	(3,813)	(4,467)
Holtsville 01 through 10	527.9	(47.72)	480.18	88	(710)	(1,163)	(1,777)	(2,356)	(3,254)	(3,742)	(4,256)	(4,910)
Holtsville 01	54.2	(4.90)	49.30	519	(279)	(732)	(1,346)	(1,926)	(2,823)	(3,311)	(3,825)	(4,479)
Holtsville 02	56.8	(5.13)	51.67	516	(282)	(735)	(1,348)	(1,928)	(2,825)	(3,314)	(3,828)	(4,481)
Holtsville 03	51.2	(4.63)	46.57	521	(277)	(730)	(1,343)	(1,923)	(2,820)	(3,309)	(3,823)	(4,476)
Holtsville 04	53.0	(4.79)	48.21	520	(278)	(731)	(1,345)	(1,924)	(2,822)	(3,310)	(3,824)	(4,478)
Holtsville 05	52.6	(4.76)	47.84	520	(278)	(731)	(1,344)	(1,924)	(2,821)	(3,310)	(3,824)	(4,478)
Holtsville 06	49.4	(4.47)	44.93	523	(275)	(728)	(1,342)	(1,921)	(2,818)	(3,307)	(3,821)	(4,475)
Holtsville 07	54.0	(4.88)	49.12	519	(279)	(732)	(1,346)	(1,925)	(2,823)	(3,311)	(3,825)	(4,479)
Holtsville 08	49.9	(4.51)	45.39	523	(275)	(728)	(1,342)	(1,922)	(2,819)	(3,307)	(3,821)	(4,475)
Holtsville 09	55.4	(5.01)	50.39	518	(280)	(733)	(1,347)	(1,927)	(2,824)	(3,312)	(3,826)	(4,480)
Holtsville 10	51.4	(4.65)	46.75	521	(277)	(730)	(1,343)	(1,923)	(2,820)	(3,309)	(3,823)	(4,477)
Shoreham GT 3 & 4	84.7	(8.74)	75.96	492	(306)	(759)	(1,373)	(1,952)	(2,849)	(3,338)	(3,852)	(4,506)
Shoreham GT3	42.9	(4.43)	38.47	530	(269)	(721)	(1,335)	(1,915)	(2,812)	(3,301)	(3,815)	(4,468)
Shoreham GT4	41.8	(4.31)	37.49	531	(268)	(720)	(1,334)	(1,914)	(2,811)	(3,300)	(3,814)	(4,467)
East Hampton GT 01, 2, 3, & 4	23.8	(2.47)	21.33	547	(251)	(704)	(1,318)	(1,898)	(2,795)	(3,283)	(3,797)	(4,451)
East Hampton GT 01	18.4	(1.66)	16.74	551	(247)	(700)	(1,313)	(1,893)	(2,790)	(3,279)	(3,793)	(4,446)
East Hampton 2	1.8	(0.27)	1.53	566	(232)	(684)	(1,298)	(1,878)	(2,775)	(3,264)	(3,778)	(4,431)
East Hampton 3	1.8	(0.27)	1.53	566	(232)	(684)	(1,298)	(1,878)	(2,775)	(3,264)	(3,778)	(4,431)
East Hampton 4	1.8	(0.27)	1.53	566	(232)	(684)	(1,298)	(1,878)	(2,775)	(3,264)	(3,778)	(4,431)
Southold 1	9.5	(0.98)	8.52	559	(239)	(691)	(1,305)	(1,885)	(2,782)	(3,271)	(3,785)	(4,438)
S Hampton 1	8.1	(0.84)	7.26	561	(237)	(690)	(1,304)	(1,884)	(2,781)	(3,269)	(3,783)	(4,437)
Freeport CT 1 & 2	88.8	(9.16)	79.64	488	(310)	(763)	(1,376)	(1,956)	(2,853)	(3,342)	(3,856)	(4,509)
Freeport CT 1	45.8	(4.73)	41.07	527	(271)	(724)	(1,338)	(1,917)	(2,815)	(3,303)	(3,817)	(4,471)
Freeport CT 2	43.0	(4.44)	38.56	529	(269)	(721)	(1,335)	(1,915)	(2,812)	(3,301)	(3,815)	(4,468)
Flynn	139.5	(6.57)	132.93	435	(363)	(816)	(1,430)	(2,009)	(2,906)	(3,395)	(3,909)	(4,563)

Statewide System Margin												
			Year	2026	2027	2028	2029	2030	2031	2032	2033	2034
Statewide System Margin Summer Peak - Expected Summer Weather, Normal Transfer Criteria (MW) (1)				568	(230)	(683)	(1,297)	(1,876)	(2,773)	(3,262)	(3,776)	(4,430)
Unit Name	Summer DMNC (MW)	NERC 5-Year Class Average De-Rate (MW)	Summer De-Rated Capability (MW)	Transmission Security Margin Considering Impact of Generator Outage (Retire, Mothball, IIFO)								
Greenport GT1	51.0	(4.61)	46.39	522	(276)	(729)	(1,343)	(1,923)	(2,820)	(3,308)	(3,822)	(4,476)
Far Rockaway GT1 & GT2[3]	-	-	-	-	-	-	-	-	-	-	-	-
Far Rockaway GT1[3]	-	-	-	-	-	-	-	-	-	-	-	-
Far Rockaway GT2[3]	-	-	-	-	-	-	-	-	-	-	-	-
Bethpage	51.0	(2.40)	48.60	519	(279)	(732)	(1,345)	(1,925)	(2,822)	(3,311)	(3,825)	(4,478)
Bethpage 3	75.7	(3.57)	72.13	496	(302)	(755)	(1,369)	(1,948)	(2,846)	(3,334)	(3,848)	(4,502)
Bethpage GT4	43.7	(4.51)	39.19	529	(269)	(722)	(1,336)	(1,915)	(2,813)	(3,301)	(3,815)	(4,469)
Stony Brook (BTM:NG)	0.0	0.00	0.00	568	(230)	(683)	(1,297)	(1,876)	(2,773)	(3,262)	(3,776)	(4,430)
Brentwood	45.0	(4.64)	40.36	528	(270)	(723)	(1,337)	(1,917)	(2,814)	(3,302)	(3,816)	(4,470)
Pilgrim GT1 & GT2	83.6	(8.63)	74.97	493	(305)	(758)	(1,372)	(1,951)	(2,848)	(3,337)	(3,851)	(4,505)
Pilgrim GT1	41.3	(4.26)	37.04	531	(267)	(720)	(1,334)	(1,913)	(2,810)	(3,299)	(3,813)	(4,467)
Pilgrim GT2	42.3	(4.37)	37.93	530	(268)	(721)	(1,335)	(1,914)	(2,811)	(3,300)	(3,814)	(4,468)
Pinelawn Power 1[3]	-	-	-	-	-	-	-	-	-	-	-	-
Caithness_CC_1	313.5	(14.77)	298.73	269	(529)	(982)	(1,595)	(2,175)	(3,072)	(3,561)	(4,075)	(4,728)
Islip (RR)	8.0	(0.87)	7.13	561	(237)	(690)	(1,304)	(1,883)	(2,781)	(3,269)	(3,783)	(4,437)
Babylon (RR)	15.7	(1.70)	14.00	554	(244)	(697)	(1,311)	(1,890)	(2,787)	(3,276)	(3,790)	(4,444)
Huntington (RR)	24.8	(2.69)	22.11	546	(252)	(705)	(1,319)	(1,898)	(2,796)	(3,284)	(3,798)	(4,452)

Notes

1. Utilizes the most severe margin result from baseline or higher demand forecasts.
2. Utilizes the next largest generation contingency outage which is the loss of the Cricket Valley CC1, CC2, & CC3.
3. Unit is modeled out of service beginning in 2026 in the baseline margin calculation.
4. Unit is modeled out of service beginning in 2031 in the baseline margin calculation.

Figure 67: AOI - Lower Hudson Valley Transmission Security Margin

Lower Hudson Valley												
			Year	2026	2027	2028	2029	2030	2031	2032	2033	2034
Lower Hudson Valley Transmission Security Margin, Summer Peak - Expected Summer Weather, Normal Transfer Criteria (MW) (1)				1,619	1,416	1,350	1,151	694	38	(91)	(369)	(665)
Unit Name	Summer DMNC (MW)	NERC 5-Year Class Average De-Rate (MW)	Summer De-Rated Capability (MW)	Transmission Security Margin Considering Impact of Generator Outage (Retire, Mothball, IIFO)								
Bowline 1 & 2	1,136.3	(123.29)	1,013.01	606	403	337	138	(319)	(975)	(1,104)	(1,382)	(1,678)
Bowline 1	565.1	(61.31)	503.79	1,115	912	846	647	191	(465)	(595)	(873)	(1,169)
Bowline 2	571.2	(61.98)	509.22	1,110	907	841	642	185	(471)	(601)	(878)	(1,175)
Danskammer 1, 2, 3, & 4[3]	-	-	-	-	-	-	-	-	-	-	-	-
Danskammer 1[3]	-	-	-	-	-	-	-	-	-	-	-	-
Danskammer 2[3]	-	-	-	-	-	-	-	-	-	-	-	-
Danskammer 3[3]	-	-	-	-	-	-	-	-	-	-	-	-
Danskammer 4[3]	-	-	-	-	-	-	-	-	-	-	-	-
Roseton 1 & 2	1,224.1	(132.81)	1,091.29	528	325	259	60	(397)	(1,053)	(1,183)	(1,460)	(1,757)
Roseton 1	616.8	(66.92)	549.88	1,069	866	800	601	145	(512)	(641)	(919)	(1,215)
Roseton 2	607.3	(65.89)	541.41	1,078	874	809	610	153	(503)	(633)	(910)	(1,207)
Hillburn GT	34.7	(3.14)	31.56	1,588	1,384	1,319	1,120	663	7	(123)	(400)	(697)
Shoemaker GT	32.3	(2.92)	29.38	1,590	1,386	1,321	1,122	665	9	(121)	(398)	(695)
DCRRA	6.3	(0.68)	5.62	1,614	1,410	1,344	1,146	689	33	(97)	(374)	(671)
CPV Valley CC1 & CC2	649.8	(30.61)	619.19	1,000	797	731	532	75	(581)	(711)	(988)	(1,285)
CPV Valley CC1	320.4	(15.09)	305.31	1,314	1,111	1,045	846	389	(267)	(397)	(674)	(971)
CPV Valley CC2	329.4	(15.51)	313.89	1,305	1,102	1,036	837	381	(276)	(405)	(683)	(979)
Cricket Valley CC1, CC2, & CC3	1,021.6	(48.12)	973.48	646	442	377	178	(279)	(935)	(1,065)	(1,342)	(1,639)
Cricket Valley CC1	349.7	(16.47)	333.23	1,286	1,083	1,017	818	361	(295)	(425)	(702)	(999)
Cricket Valley CC2	345.5	(16.27)	329.23	1,290	1,087	1,021	822	365	(291)	(421)	(698)	(995)
Cricket Valley CC3	326.4	(15.37)	311.03	1,308	1,105	1,039	840	383	(273)	(402)	(680)	(976)
Wheelabrator Westchester	53.5	(5.80)	47.70	1,572	1,368	1,302	1,104	647	(9)	(139)	(416)	(713)
Arthur Kill ST 2 & 3	883.6	(95.87)	787.73	831	628	562	364	(93)	(749)	(879)	(1,157)	(1,453)
Arthur Kill ST 2	363.2	(39.41)	323.79	1,295	1,092	1,026	827	371	(285)	(415)	(693)	(989)
Arthur Kill ST 3	520.4	(56.46)	463.94	1,155	952	886	687	230	(426)	(555)	(833)	(1,129)
Brooklyn Navy Yard	249.2	(11.74)	237.46	1,382	1,178	1,113	914	457	(199)	(329)	(606)	(903)
Astoria 2, 3, & 5	902.3	(97.90)	804.40	815	611	546	347	(110)	(766)	(896)	(1,173)	(1,470)
Astoria 2	158.0	(17.14)	140.86	1,478	1,275	1,209	1,010	554	(102)	(232)	(510)	(806)
Astoria 3	371.1	(40.26)	330.84	1,288	1,085	1,019	820	364	(292)	(422)	(700)	(996)
Astoria 5	373.2	(40.49)	332.71	1,286	1,083	1,017	819	362	(294)	(424)	(701)	(998)
Ravenswood ST 01, 02, & 03	1,724.8	(187.14)	1,537.66	82	(122)	(188)	(386)	(843)	(1,499)	(1,629)	(1,906)	(2,203)

Lower Hudson Valley												
			Year	2026	2027	2028	2029	2030	2031	2032	2033	2034
Lower Hudson Valley Transmission Security Margin, Summer Peak - Expected Summer Weather, Normal Transfer Criteria (MW) (1)				1,619	1,416	1,350	1,151	694	38	(91)	(369)	(665)
Unit Name	Summer DMNC (MW)	NERC 5-Year Class Average De-Rate (MW)	Summer De-Rated Capability (MW)	Transmission Security Margin Considering Impact of Generator Outage (Retire, Mothball, IIFO)								
Ravenswood ST 01	364.5	(39.55)	324.95	1,294	1,091	1,025	826	369	(287)	(416)	(694)	(990)
Ravenswood ST 02	375.2	(40.71)	334.49	1,285	1,081	1,016	817	360	(296)	(426)	(703)	(1,000)
Ravenswood ST 03	985.1	(106.88)	878.22	741	538	472	273	(184)	(840)	(970)	(1,247)	(1,544)
Ravenswood CC 04	222.2	(10.47)	211.73	1,407	1,204	1,138	940	483	(173)	(303)	(581)	(877)
East River 1, 2, 6, & 7	630.7	(49.54)	581.16	1,038	835	769	570	113	(543)	(673)	(950)	(1,246)
East River 1	153.2	(7.22)	145.98	1,473	1,270	1,204	1,005	548	(108)	(237)	(515)	(811)
East River 2	154.5	(7.28)	147.22	1,472	1,269	1,203	1,004	547	(109)	(239)	(516)	(813)
East River 6	141.5	(15.35)	126.15	1,493	1,290	1,224	1,025	568	(88)	(218)	(495)	(791)
East River 7	181.5	(19.69)	161.81	1,457	1,254	1,188	989	533	(123)	(253)	(531)	(827)
Linden Cogen	748.2	(35.24)	712.96	906	703	637	438	(19)	(675)	(804)	(1,082)	(1,378)
KIAC_JFK (BTM:NG)	105.4	(4.96)	100.44	1,519	1,315	1,250	1,051	594	(62)	(192)	(469)	(766)
Gowanus 5 & 6[2]	79.9	(8.25)	71.65	1,548	1,344	1,278	1,080	623	-	-	-	-
Gowanus 5[2]	40.0	(4.13)	35.87	1,583	1,380	1,314	1,115	659	-	-	-	-
Gowanus 6[2]	39.9	(4.12)	35.78	1,583	1,380	1,314	1,115	659	-	-	-	-
Kent[2]	46.0	(4.75)	41.25	1,578	1,375	1,309	1,110	653	-	-	-	-
Pouch[2]	44.7	(4.61)	40.09	1,579	1,376	1,310	1,111	654	-	-	-	-
Hellgate 1 & 2[2]	79.5	(8.20)	71.30	1,548	1,345	1,279	1,080	623	-	-	-	-
Hellgate 1[2]	39.9	(4.12)	35.78	1,583	1,380	1,314	1,115	659	-	-	-	-
Hellgate 2[2]	39.6	(4.09)	35.51	1,584	1,380	1,315	1,116	659	-	-	-	-
Harlem River 1 & 2[2]	79.5	(8.20)	71.30	1,548	1,345	1,279	1,080	623	-	-	-	-
Harlem River 1[2]	39.9	(4.12)	35.78	1,583	1,380	1,314	1,115	659	-	-	-	-
Harlem River 2[2]	39.6	(4.09)	35.51	1,584	1,380	1,315	1,116	659	-	-	-	-
Vernon Blvd 2 & 3[2]	79.9	(8.25)	71.65	1,548	1,344	1,278	1,080	623	-	-	-	-
Vernon Blvd 2[2]	40.0	(4.13)	35.87	1,583	1,380	1,314	1,115	659	-	-	-	-
Vernon Blvd 3[2]	39.9	(4.12)	35.78	1,583	1,380	1,314	1,115	659	-	-	-	-
Astoria CC 1 & 2	474.0	(22.33)	451.67	1,168	964	898	700	243	(413)	(543)	(820)	(1,117)
Astoria CC 1	237.0	(11.16)	225.84	1,393	1,190	1,124	925	469	(187)	(317)	(595)	(891)
Astoria CC 2	237.0	(11.16)	225.84	1,393	1,190	1,124	925	469	(187)	(317)	(595)	(891)
Astoria East Energy CC1 & CC2	582.8	(27.45)	555.35	1,064	860	795	596	139	(517)	(647)	(924)	(1,221)
Astoria East Energy - CC1	291.4	(13.72)	277.68	1,342	1,138	1,072	874	417	(239)	(369)	(646)	(943)
Astoria East Energy - CC2	291.4	(13.72)	277.68	1,342	1,138	1,072	874	417	(239)	(369)	(646)	(943)

Lower Hudson Valley												
			Year	2026	2027	2028	2029	2030	2031	2032	2033	2034
Lower Hudson Valley Transmission Security Margin, Summer Peak - Expected Summer Weather, Normal Transfer Criteria (MW) (1)				1,619	1,416	1,350	1,151	694	38	(91)	(369)	(665)
Unit Name	Summer DMNC (MW)	NERC 5-Year Class Average De-Rate (MW)	Summer De-Rated Capability (MW)	Transmission Security Margin Considering Impact of Generator Outage (Retire, Mothball, IIFO)								
Astoria Energy 2 - CC3 & CC4	570.3	(26.86)	543.44	1,076	872	807	608	151	(505)	(635)	(912)	(1,209)
Astoria Energy 2 - CC3	285.0	(13.42)	271.58	1,348	1,144	1,079	880	423	(233)	(363)	(640)	(937)
Astoria Energy 2 - CC4	285.3	(13.44)	271.86	1,347	1,144	1,078	879	423	(233)	(363)	(641)	(937)
Bayonne EC CT G1 through G10	604.8	(54.67)	550.13	1,069	866	800	601	144	(512)	(642)	(919)	(1,215)
Bayonne EC CTG1	62.0	(5.60)	56.40	1,563	1,359	1,294	1,095	638	(18)	(148)	(425)	(722)
Bayonne EC CTG2	58.0	(5.24)	52.76	1,566	1,363	1,297	1,099	642	(14)	(144)	(422)	(718)
Bayonne EC CTG3	58.1	(5.25)	52.85	1,566	1,363	1,297	1,098	642	(14)	(144)	(422)	(718)
Bayonne EC CTG4	61.1	(5.52)	55.58	1,564	1,360	1,295	1,096	639	(17)	(147)	(424)	(721)
Bayonne EC CTG5	61.8	(5.59)	56.21	1,563	1,360	1,294	1,095	638	(18)	(148)	(425)	(722)
Bayonne EC CTG6	61.4	(5.55)	55.85	1,563	1,360	1,294	1,095	639	(17)	(147)	(425)	(721)
Bayonne EC CTG7	59.7	(5.40)	54.30	1,565	1,362	1,296	1,097	640	(16)	(146)	(423)	(720)
Bayonne EC CTG8	60.0	(5.42)	54.58	1,565	1,361	1,296	1,097	640	(16)	(146)	(423)	(720)
Bayonne EC CTG9	61.3	(5.54)	55.76	1,563	1,360	1,294	1,096	639	(17)	(147)	(425)	(721)
Bayonne EC CTG10	61.4	(5.55)	55.85	1,563	1,360	1,294	1,095	639	(17)	(147)	(425)	(721)

Notes

1. Utilizes the most severe margin result from baseline coincident, baseline nocoincident, and higher demand forecasts.
2. Unit is modeled out of service beginning in 2031 in the baseline margin calculation.
3. Unit is modeled out of service beginning in 2026 in the baseline margin calculation.

Figure 68: AOI - New York City Transmission Security Margin

New York City												
			Year	2026	2027	2028	2029	2030	2031	2032	2033	2034
New York City Transmission Security Margin, Summer Peak - Expected Summer Weather, Normal Transfer Criteria (MW) (1)				150	202	92	(37)	(148)	(656)	(806)	(966)	(1,136)
Unit Name	Summer DMNC (MW)	NERC 5-Year Class Average De-Rate (MW)	Summer De-Rated Capability (MW)	Transmission Security Margin Considering Impact of Generator Outage (Retire, Mothball, IIFO)								
Arthur Kill ST 2 & 3	883.6	(95.87)	787.73	(638)	(586)	(696)	(824)	(936)	(1,444)	(1,594)	(1,754)	(1,924)
Arthur Kill ST 2	363.2	(39.41)	323.79	(174)	(122)	(232)	(360)	(472)	(980)	(1,130)	(1,290)	(1,460)
Arthur Kill ST 3	520.4	(56.46)	463.94	(314)	(262)	(372)	(501)	(612)	(1,120)	(1,270)	(1,430)	(1,600)
Brooklyn Navy Yard	249.2	(11.74)	237.46	(87)	(36)	(146)	(274)	(386)	(893)	(1,043)	(1,203)	(1,373)
Astoria 2, 3, & 5	902.3	(97.90)	804.40	(654)	(603)	(713)	(841)	(953)	(1,460)	(1,610)	(1,770)	(1,940)
Astoria 2	158.0	(17.14)	140.86	9	61	(49)	(177)	(289)	(797)	(947)	(1,107)	(1,277)
Astoria 3	371.1	(40.26)	330.84	(181)	(129)	(239)	(367)	(479)	(987)	(1,137)	(1,297)	(1,467)
Astoria 5	373.2	(40.49)	332.71	(183)	(131)	(241)	(369)	(481)	(989)	(1,139)	(1,299)	(1,469)
Ravenswood ST 01, 02, & 03[2]	1,724.8	(187.14)	1,537.66	(652)	(601)	(711)	(839)	(1,051)	(1,558)	(1,708)	(1,868)	(2,038)
Ravenswood ST 01	364.5	(39.55)	324.95	(175)	(123)	(233)	(362)	(473)	(981)	(1,131)	(1,291)	(1,461)
Ravenswood ST 02	375.2	(40.71)	334.49	(184)	(133)	(243)	(371)	(483)	(990)	(1,140)	(1,300)	(1,470)
Ravenswood ST 03[2]	985.1	(106.88)	878.22	7	59	(51)	(180)	(391)	(899)	(1,049)	(1,209)	(1,379)
Ravenswood CC 04	222.2	(10.47)	211.73	(62)	(10)	(120)	(248)	(360)	(868)	(1,018)	(1,178)	(1,348)
East River 1, 2, 6, & 7	630.7	(49.54)	581.16	(431)	(379)	(489)	(618)	(729)	(1,237)	(1,387)	(1,547)	(1,717)
East River 1	153.2	(7.22)	145.98	4	56	(54)	(183)	(294)	(802)	(952)	(1,112)	(1,282)
East River 2	154.5	(7.28)	147.22	3	54	(56)	(184)	(296)	(803)	(953)	(1,113)	(1,283)
East River 6	141.5	(15.35)	126.15	24	76	(34)	(163)	(274)	(782)	(932)	(1,092)	(1,262)
East River 7	181.5	(19.69)	161.81	(12)	40	(70)	(198)	(310)	(818)	(968)	(1,128)	(1,298)
Linden Cogen	748.2	(35.24)	712.96	(563)	(511)	(621)	(750)	(861)	(1,369)	(1,519)	(1,679)	(1,849)
KIAC_JFK (BTM:NG)	105.4	(4.96)	100.44	50	101	(9)	(137)	(249)	(756)	(906)	(1,066)	(1,236)
Gowanus 5 & 6[3]	79.9	(8.25)	71.65	78	130	20	(108)	(220)	-	-	-	-
Gowanus 5[3]	40.0	(4.13)	35.87	114	166	56	(72)	(184)	-	-	-	-
Gowanus 6[3]	39.9	(4.12)	35.78	114	166	56	(72)	(184)	-	-	-	-
Kent[3]	46.0	(4.75)	41.25	109	160	50	(78)	(190)	-	-	-	-
Pouch[3]	44.7	(4.61)	40.09	110	162	52	(77)	(188)	-	-	-	-
Hellgate 1 & 2[3]	79.5	(8.20)	71.30	79	130	20	(108)	(220)	-	-	-	-
Hellgate 1[3]	39.9	(4.12)	35.78	114	166	56	(72)	(184)	-	-	-	-
Hellgate 2[3]	39.6	(4.09)	35.51	115	166	56	(72)	(184)	-	-	-	-
Harlem River 1 & 2[3]	79.5	(8.20)	71.30	79	130	20	(108)	(220)	-	-	-	-
Harlem River 1[3]	39.9	(4.12)	35.78	114	166	56	(72)	(184)	-	-	-	-
Harlem River 2[3]	39.6	(4.09)	35.51	115	166	56	(72)	(184)	-	-	-	-
Vernon Blvd 2 & 3[3]	79.9	(8.25)	71.65	78	130	20	(108)	(220)	-	-	-	-
Vernon Blvd 2[3]	40.0	(4.13)	35.87	114	166	56	(72)	(184)	-	-	-	-

New York City												
			Year	2026	2027	2028	2029	2030	2031	2032	2033	2034
New York City Transmission Security Margin, Summer Peak - Expected Summer Weather, Normal Transfer Criteria (MW) (1)				150	202	92	(37)	(148)	(656)	(806)	(966)	(1,136)
Unit Name	Summer DMNC (MW)	NERC 5-Year Class Average De-Rate (MW)	Summer De-Rated Capability (MW)	Transmission Security Margin Considering Impact of Generator Outage (Retire, Mothball, IIFO)								
Vernon Blvd 3[3]	39.9	(4.12)	35.78	114	166	56	(72)	(184)	-	-	-	-
Astoria CC 1 & 2	474.0	(22.33)	451.67	(302)	(250)	(360)	(488)	(600)	(1,107)	(1,257)	(1,417)	(1,587)
Astoria CC 1	237.0	(11.16)	225.84	(76)	(24)	(134)	(262)	(374)	(882)	(1,032)	(1,192)	(1,362)
Astoria CC 2	237.0	(11.16)	225.84	(76)	(24)	(134)	(262)	(374)	(882)	(1,032)	(1,192)	(1,362)
Astoria East Energy CC1 & CC2	582.8	(27.45)	555.35	(405)	(354)	(464)	(592)	(704)	(1,211)	(1,361)	(1,521)	(1,691)
Astoria East Energy - CC1	291.4	(13.72)	277.68	(128)	(76)	(186)	(314)	(426)	(933)	(1,083)	(1,243)	(1,413)
Astoria East Energy - CC2	291.4	(13.72)	277.68	(128)	(76)	(186)	(314)	(426)	(933)	(1,083)	(1,243)	(1,413)
Astoria Energy 2 - CC3 & CC4	570.3	(26.86)	543.44	(393)	(342)	(452)	(580)	(692)	(1,199)	(1,349)	(1,509)	(1,679)
Astoria Energy 2 - CC3	285.0	(13.42)	271.58	(121)	(70)	(180)	(308)	(420)	(927)	(1,077)	(1,237)	(1,407)
Astoria Energy 2 - CC4	285.3	(13.44)	271.86	(122)	(70)	(180)	(308)	(420)	(928)	(1,078)	(1,238)	(1,408)
Bayonne EC CT G1 through G10	604.8	(54.67)	550.13	(400)	(348)	(458)	(587)	(698)	(1,206)	(1,356)	(1,516)	(1,686)
Bayonne EC CTG1	62.0	(5.60)	56.40	94	145	35	(93)	(205)	(712)	(862)	(1,022)	(1,192)
Bayonne EC CTG2	58.0	(5.24)	52.76	97	149	39	(89)	(201)	(709)	(859)	(1,019)	(1,189)
Bayonne EC CTG3	58.1	(5.25)	52.85	97	149	39	(89)	(201)	(709)	(859)	(1,019)	(1,189)
Bayonne EC CTG4	61.1	(5.52)	55.58	95	146	36	(92)	(204)	(711)	(861)	(1,021)	(1,191)
Bayonne EC CTG5	61.8	(5.59)	56.21	94	145	35	(93)	(205)	(712)	(862)	(1,022)	(1,192)
Bayonne EC CTG6	61.4	(5.55)	55.85	94	146	36	(92)	(204)	(712)	(862)	(1,022)	(1,192)
Bayonne EC CTG7	59.7	(5.40)	54.30	96	147	37	(91)	(203)	(710)	(860)	(1,020)	(1,190)
Bayonne EC CTG8	60.0	(5.42)	54.58	96	147	37	(91)	(203)	(710)	(860)	(1,020)	(1,190)
Bayonne EC CTG9	61.3	(5.54)	55.76	94	146	36	(92)	(204)	(712)	(862)	(1,022)	(1,192)
Bayonne EC CTG10	61.4	(5.55)	55.85	94	146	36	(92)	(204)	(712)	(862)	(1,022)	(1,192)

Notes

1. Utilizes the most severe margin result from baseline coincident, baseline nocoincident, and higher demand forecasts.
2. In all years the most limiting contingency includes the loss of Ravenswood 3. For this calculation the margin based on the loss of two transmission elements is utilized. Other combinations with loss of generation may be more limiting.
3. Unit is modeled out of service beginning in 2031 in the baseline margin calculation.

Figure 69: AOI - Long Island Transmission Security Margin

Long Island												
			Year	2026	2027	2028	2029	2030	2031	2032	2033	2034
Long Island Transmission Security Margin, Summer Peak - Expected Summer Weather, Normal Transfer Criteria (MW) (1)				301	(6)	87	63	1,969	1,862	1,808	1,750	1,671
Unit Name	Summer DMNC (MW)	NERC 5-Year Class Average De-Rate (MW)	Summer De-Rated Capability (MW)	Transmission Security Margin Considering Impact of Generator Outage (Retire, Mothball, IIFO)								
Greenport IC 4, 5, & 6	5.6	(0.83)	4.77	296	(10)	82	58	1,964	1,857	1,803	1,745	1,667
Greenport IC 4	1.0	(0.15)	0.85	300	(7)	86	62	1,968	1,861	1,807	1,749	1,671
Greenport IC 5	1.5	(0.22)	1.28	300	(7)	86	61	1,968	1,860	1,807	1,749	1,670
Greenport IC 6	3.1	(0.46)	2.64	298	(8)	85	60	1,966	1,859	1,805	1,747	1,669
Freeport 1-2, 1-3, & 2-3	19.2	(2.21)	16.99	284	(23)	70	46	1,952	1,845	1,791	1,733	1,654
Freeport 1-2	2.3	(0.34)	1.96	299	(8)	85	61	1,967	1,860	1,806	1,748	1,670
Freeport 1-3	2.7	(0.40)	2.30	299	(8)	85	60	1,967	1,859	1,806	1,748	1,669
Freeport 2-3	14.2	(1.47)	12.73	288	(18)	74	50	1,956	1,849	1,795	1,737	1,659
Charles P Killer 09 through 14	13.5	(1.78)	11.72	289	(17)	75	51	1,957	1,850	1,796	1,738	1,660
Charles P Keller 09	1.6	(0.21)	1.39	300	(7)	86	61	1,968	1,860	1,807	1,749	1,670
Charles P Keller 10	1.6	(0.21)	1.39	300	(7)	86	61	1,968	1,860	1,807	1,749	1,670
Charles P Keller 11	2.4	(0.32)	2.08	299	(8)	85	61	1,967	1,859	1,806	1,748	1,669
Charles P Keller 12	2.5	(0.33)	2.17	299	(8)	85	60	1,967	1,859	1,806	1,748	1,669
Charles P Keller 13	2.5	(0.33)	2.17	299	(8)	85	60	1,967	1,859	1,806	1,748	1,669
Charles P Keller 14	2.9	(0.38)	2.52	298	(8)	85	60	1,967	1,859	1,806	1,748	1,669
Wading River 1, 2, & 3	214.8	(22.17)	192.63	108	(198)	(105)	(130)	1,776	1,669	1,615	1,557	1,479
Wading River 1	77.6	(8.01)	69.59	231	(75)	18	(7)	1,900	1,792	1,738	1,680	1,602
Wading River 2	64.3	(6.64)	57.66	243	(63)	30	5	1,911	1,804	1,750	1,692	1,614
Wading River 3	72.9	(7.52)	65.38	236	(71)	22	(3)	1,904	1,796	1,743	1,685	1,606
Barrett ST 01 & 02	380.5	(41.28)	339.22	(38)	(345)	(252)	(277)	1,630	1,522	1,469	1,411	1,332
Barrett ST 01	192.0	(20.83)	171.17	130	(177)	(84)	(109)	1,798	1,690	1,637	1,579	1,500
Barrett ST 02	188.5	(20.45)	168.05	133	(174)	(81)	(105)	1,801	1,694	1,640	1,582	1,503
Barrett GT 01 through 12	246.6	(23.47)	223.13	78	(229)	(136)	(160)	1,746	1,638	1,585	1,527	1,448
Barrett GT 01	13.7	(1.41)	12.29	289	(18)	75	50	1,957	1,849	1,796	1,738	1,659
Barrett GT 02	13.6	(1.40)	12.20	289	(18)	75	50	1,957	1,849	1,796	1,738	1,659
Barrett 03	12.2	(1.26)	10.94	290	(17)	76	52	1,958	1,851	1,797	1,739	1,661
Barrett 04	14.5	(1.50)	13.00	288	(19)	74	50	1,956	1,849	1,795	1,737	1,658
Barrett 05	12.0	(1.24)	10.76	290	(16)	76	52	1,958	1,851	1,797	1,739	1,661
Barrett 06	12.9	(1.33)	11.57	289	(17)	76	51	1,958	1,850	1,796	1,738	1,660
Barrett 08	12.8	(1.32)	11.48	289	(17)	76	51	1,958	1,850	1,797	1,739	1,660
Barrett 09	38.6	(3.49)	35.11	266	(41)	52	28	1,934	1,826	1,773	1,715	1,636
Barrett 10	39.2	(3.54)	35.66	265	(41)	52	27	1,933	1,826	1,772	1,714	1,636
Barrett 11	38.2	(3.45)	34.75	266	(40)	52	28	1,934	1,827	1,773	1,715	1,637
Barrett 12	38.9	(3.52)	35.38	266	(41)	52	27	1,934	1,826	1,773	1,715	1,636

New York ISO

Long Island												
			Year	2026	2027	2028	2029	2030	2031	2032	2033	2034
Long Island Transmission Security Margin, Summer Peak - Expected Summer Weather, Normal Transfer Criteria (MW) (1)				301	(6)	87	63	1,969	1,862	1,808	1,750	1,671
Unit Name	Summer DMNC (MW)	NERC 5-Year Class Average De-Rate (MW)	Summer De-Rated Capability (MW)	Transmission Security Margin Considering Impact of Generator Outage (Retire, Mothball, IIFO)								
Northport 1, 2, 3, and 4	1,582.2	(171.67)	1,410.53	(1,110)	(1,416)	(1,323)	(1,348)	559	451	397	339	261
Northport 1	399.0	(43.29)	355.71	(55)	(361)	(269)	(293)	1,613	1,506	1,452	1,394	1,316
Northport 2	399.0	(43.29)	355.71	(55)	(361)	(269)	(293)	1,613	1,506	1,452	1,394	1,316
Northport 3	386.2	(41.90)	344.30	(43)	(350)	(257)	(282)	1,625	1,517	1,464	1,406	1,327
Northport 4	398.0	(43.18)	354.82	(54)	(360)	(268)	(292)	1,614	1,507	1,453	1,395	1,317
Port Jefferson GT 02 & 03	79.3	(8.18)	71.12	230	(77)	16	(8)	1,898	1,790	1,737	1,679	1,600
Port Jefferson GT 02	39.1	(4.04)	35.06	266	(41)	52	28	1,934	1,827	1,773	1,715	1,636
Port Jefferson GT 03	40.2	(4.15)	36.05	265	(42)	51	27	1,933	1,826	1,772	1,714	1,635
Port Jefferson 3 & 4	380.0	(41.23)	338.77	(38)	(344)	(252)	(276)	1,630	1,523	1,469	1,411	1,333
Port Jefferson 3	191.0	(20.72)	170.28	131	(176)	(83)	(108)	1,799	1,691	1,638	1,580	1,501
Port Jefferson 4	189.0	(20.51)	168.49	132	(174)	(81)	(106)	1,801	1,693	1,640	1,582	1,503
Hempstead (RR)	74.2	(8.05)	66.15	235	(72)	21	(3)	1,903	1,795	1,742	1,684	1,605
Glenwood GT 02, 04, & 05	123.9	(12.79)	111.11	190	(117)	(24)	(48)	1,858	1,750	1,697	1,639	1,560
Glenwood GT 02	40.3	(4.16)	36.14	265	(42)	51	27	1,933	1,825	1,772	1,714	1,635
Glenwood GT 04	41.9	(4.32)	37.58	263	(43)	50	25	1,932	1,824	1,770	1,712	1,634
Glenwood GT 05	41.7	(4.30)	37.40	264	(43)	50	25	1,932	1,824	1,771	1,713	1,634
Holtsville 01 through 10	527.9	(47.72)	480.18	(179)	(486)	(393)	(418)	1,489	1,381	1,328	1,270	1,191
Holtsville 01	54.2	(4.90)	49.30	252	(55)	38	13	1,920	1,812	1,759	1,701	1,622
Holtsville 02	56.8	(5.13)	51.67	249	(57)	36	11	1,917	1,810	1,756	1,698	1,620
Holtsville 03	51.2	(4.63)	46.57	254	(52)	41	16	1,923	1,815	1,761	1,703	1,625
Holtsville 04	53.0	(4.79)	48.21	253	(54)	39	14	1,921	1,813	1,760	1,702	1,623
Holtsville 05	52.6	(4.76)	47.84	253	(53)	39	15	1,921	1,814	1,760	1,702	1,624
Holtsville 06	49.4	(4.47)	44.93	256	(51)	42	18	1,924	1,817	1,763	1,705	1,627
Holtsville 07	54.0	(4.88)	49.12	252	(55)	38	14	1,920	1,812	1,759	1,701	1,622
Holtsville 08	49.9	(4.51)	45.39	256	(51)	42	17	1,924	1,816	1,763	1,705	1,626
Holtsville 09	55.4	(5.01)	50.39	251	(56)	37	12	1,919	1,811	1,758	1,700	1,621
Holtsville 10	51.4	(4.65)	46.75	254	(52)	40	16	1,922	1,815	1,761	1,703	1,625
Shoreham GT 3 & 4	84.7	(8.74)	75.96	225	(82)	11	(13)	1,893	1,786	1,732	1,674	1,596
Shoreham GT3	42.9	(4.43)	38.47	262	(44)	49	24	1,931	1,823	1,770	1,712	1,633
Shoreham GT4	41.8	(4.31)	37.49	263	(43)	50	25	1,932	1,824	1,771	1,713	1,634
East Hampton GT 01, 2, 3, & 4	23.8	(2.47)	21.33	280	(27)	66	41	1,948	1,840	1,787	1,729	1,650
East Hampton GT 01	18.4	(1.66)	16.74	284	(22)	70	46	1,952	1,845	1,791	1,733	1,655
East Hampton 2	1.8	(0.27)	1.53	299	(7)	86	61	1,968	1,860	1,806	1,748	1,670
East Hampton 3	1.8	(0.27)	1.53	299	(7)	86	61	1,968	1,860	1,806	1,748	1,670
East Hampton 4	1.8	(0.27)	1.53	299	(7)	86	61	1,968	1,860	1,806	1,748	1,670

Long Island												
Year				2026	2027	2028	2029	2030	2031	2032	2033	2034
Long Island Transmission Security Margin, Summer Peak - Expected Summer Weather, Normal Transfer Criteria (MW) (1)				301	(6)	87	63	1,969	1,862	1,808	1,750	1,671
Unit Name	Summer DMNC (MW)	NERC 5-Year Class Average De-Rate (MW)	Summer De-Rated Capability (MW)	Transmission Security Margin Considering Impact of Generator Outage (Retire, Mothball, IIFO)								
Southold 1	9.5	(0.98)	8.52	292	(14)	79	54	1,961	1,853	1,800	1,742	1,663
S Hampton 1	8.1	(0.84)	7.26	294	(13)	80	55	1,962	1,854	1,801	1,743	1,664
Freeport CT 1 & 2	88.8	(9.16)	79.64	221	(85)	8	(17)	1,889	1,782	1,728	1,670	1,592
Freeport CT 1	45.8	(4.73)	41.07	260	(47)	46	22	1,928	1,820	1,767	1,709	1,630
Freeport CT 2	43.0	(4.44)	38.56	262	(44)	49	24	1,931	1,823	1,769	1,711	1,633
Flynn	139.5	(6.57)	132.93	168	(139)	(46)	(70)	1,836	1,729	1,675	1,617	1,539
Greenport GT1	51.0	(4.61)	46.39	255	(52)	41	16	1,923	1,815	1,762	1,704	1,625
Far Rockaway GT1 & GT2[2]	-	-	-	-	-	-	-	-	-	-	-	-
Far Rockaway GT1[2]	-	-	-	-	-	-	-	-	-	-	-	-
Far Rockaway GT2[2]	-	-	-	-	-	-	-	-	-	-	-	-
Bethpage	51.0	(2.40)	48.60	252	(54)	39	14	1,921	1,813	1,759	1,701	1,623
Bethpage 3	75.7	(3.57)	72.13	229	(78)	15	(9)	1,897	1,789	1,736	1,678	1,599
Bethpage GT4	43.7	(4.51)	39.19	262	(45)	48	23	1,930	1,822	1,769	1,711	1,632
Stony Brook (BTM:NG)	0.0	0.00	0.00	301	(6)	87	63	1,969	1,862	1,808	1,750	1,671
Brentwood	45.0	(4.64)	40.36	261	(46)	47	22	1,929	1,821	1,768	1,710	1,631
Pilgrim GT1 & GT2	83.6	(8.63)	74.97	226	(81)	12	(12)	1,894	1,787	1,733	1,675	1,597
Pilgrim GT1	41.3	(4.26)	37.04	264	(43)	50	26	1,932	1,825	1,771	1,713	1,634
Pilgrim GT2	42.3	(4.37)	37.93	263	(44)	49	25	1,931	1,824	1,770	1,712	1,634
Pinelawn Power 1[2]	-	-	-	-	-	-	-	-	-	-	-	-
Caithness_CC_1	313.5	(14.77)	298.73	2	(304)	(212)	(236)	1,670	1,563	1,509	1,451	1,373
Islip (RR)	8.0	(0.87)	7.13	294	(13)	80	56	1,962	1,854	1,801	1,743	1,664
Babylon (RR)	15.7	(1.70)	14.00	287	(20)	73	49	1,955	1,848	1,794	1,736	1,657
Huntington (RR)	24.8	(2.69)	22.11	279	(28)	65	41	1,947	1,839	1,786	1,728	1,649

Notes

1. Utilizes the most severe margin result from baseline coincident, baseline nocoincident, and higher demand forecasts.
2. Unit is modeled out of service beginning in 2026 in the baseline margin calculation.