Short-Term Assessment of Reliability: 2026 Quarter 2

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 2 Short-Term Assessment of Reliability ("STAR") findings for the five-year study period of April 15, 2026, through April 15, 2031, considering forecasts of peak power demand, planned upgrades to the transmission system, and changes to the generation mix over the next five years. The retirement of High Acres (Zone C, 9.6 MW nameplate) and Coxsackie GT (Zone G, 21.6 MW nameplate) as Initiating Generators[1] are evaluated in this STAR. While the ICAP Ineligible Forced Outage ("IIFO") of Far Rockaway GT1 (Zone K, 60.5 MW nameplate) was included in this assessment at the start of this STAR, the unit returned to the market on June 17, 2026 and is no longer in IIFO. As such, the results reported in this STAR have Far Rockaway GT1 returned to service. Additionally, following the start of this STAR, on May 13, 2026, Champlain Hudson Power Express ("CHPE") entered commercial operation but has yet to demonstrate its planned power capability.

Without CHPE having demonstrated its planned power capability, the NYISO continues to observe deficiencies in both New York City and the Lower Hudson Valley in the short-term horizon. As the Lower Hudson Valley deficiency would be resolved in whole or in part by the retention of Danskammer 1-4, the Lower Hudson Valley deficiency is a Generator Deactivation Reliability Need, as first identified in the 2026 Quarter 1 STAR. As further described below, Danskammer 1-4 cannot deactivate on August 1, 2026 and will be required to remain in-service until at least January 15, 2027, if permanent solutions are not available sooner. Following the issuance of this STAR, the NYISO will proceed to issue a solicitation for solutions to the Lower Hudson Valley deficiency.

Starting with the 2025 Quarter 3 STAR, the quarterly reports have continued to observe 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

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

and generation projects. As a result, maintaining reliability increasingly depends on careful management of interim conditions while permanent solutions advance.

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

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

The Short-Term Reliability Process applies only to the first five years of the planning horizon. In the 2026 Quarter 1 STAR, additional details were provided for reliability margin projections for statewide adequacy and the locality transmission security margins. On Long Island, until the Propel NY transmission project is in-service, the projected margins tighten to just 36 MW in summer 2027. Just beyond the timeframe of this STAR, even with all planned projects delivering power according to their schedules, New York City is projected to be deficient again beginning as early as summer 2031 primarily driven by the planned unavailability of the NYPA Small Plants. Absent any changes to system plans or forecasts, the NYISO expects this deficiency to be identified as a reliability need in the 2026 Quarter 3 STAR.

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 first presented in the recent 2025-2034

Comprehensive Reliability Plan (CRP), the NYISO is now incorporating aging generation risk in the 2026 RNA to better capture the likelihood of future resource unavailability and identify emerging reliability needs beyond the short-term horizon.[2] In consideration of these changes, based on preliminary RNA analysis, the NYISO expects the findings for the 2026 RNA to be directionally consistent with this 2026 Quarter 2 STAR.

Lower Hudson Valley

Consistent with the findings of the 2025 Quarter 3 and Quarter 4 STARs, the 2026 Quarter 1 STAR observed a Generator Deactivation Reliability Need. Primarily this need was driven by deficiencies in New York City and Long Island. The proposed retirement of Danskammer 1-4 evaluated in the 2026 Quarter 1 STAR further exacerbated this deficiency. The need is also impacted 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.

As discussed in the 2026 Quarter 1 STAR, upon the withdrawal of the deactivation notices for the Gowanus and Narrows barges, the deficiencies in summer 2027 and 2028 within the Lower Hudson Valley would be addressed, but the deficiencies in 2029 and 2030 would continue to be observed and are exacerbated by the retirement of Danskammer 1-4. These deficiencies are observed following the removal of the Gowanus and Narrows barges on May 1, 2029. Beyond 2030, should planned projects not enter service according to schedule and demonstrate their planned capabilities, the Lower Hudson Valley would also be impacted by the unavailability of the NYPA Small Plants. The extension of the Gowanus and Narrows barges until May 1, 2029, in accordance with the DEC Peaker Rule, helps to address the Lower Hudson Valley deficiency whereas retaining Danskammer 1-4 would not help alleviate the ongoing New York City deficiency as the Danskammer units are outside of Zone J.

With the continued operation of the Gowanus and Narrows barges, other updates to key study assumptions in this STAR, and with CHPE yet to demonstrate its planned power capability, deficiencies within the Lower Hudson Valley continue to be observed.

The magnitude and duration of the Bulk Power Transmission Facility (“BPTF”) deficiency in the Lower Hudson Valley for this STAR are:

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

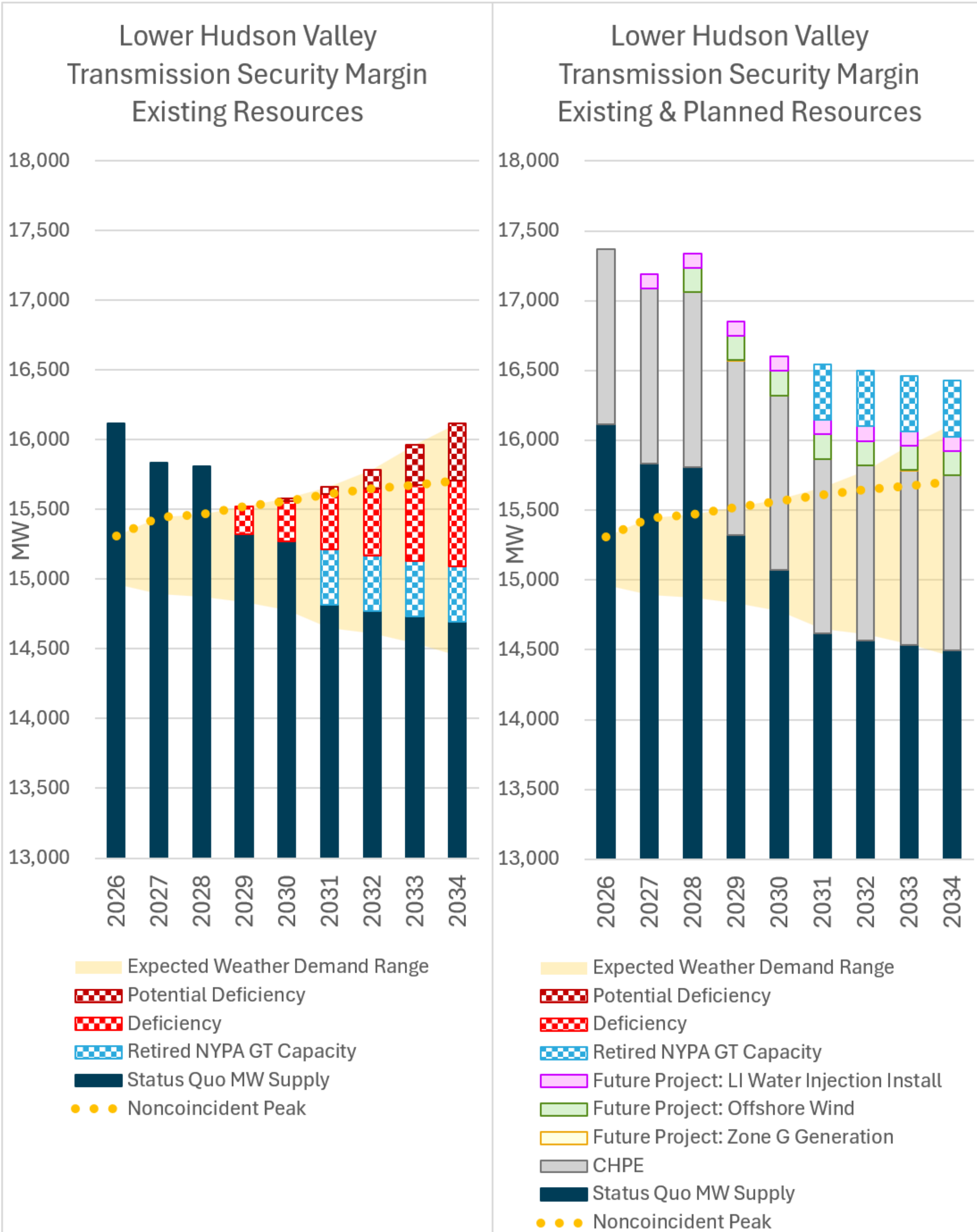
<u>Lower Hudson Valley BPTF Deficiency</u>:

Summer Peak	**2026**	**2027**	**2028**	**2029**	**2030**
MW Deficiency	None	None	None	184-201	291-309
Duration (hours)	None	None	None	3-5	4-5
MWh	None	None	None	387-1,287	746-2,066

As the Lower Hudson Valley BPTF deficiency would be resolved in whole or in part by the retention of Danskammer 1-4, the Lower Hudson Valley deficiency is a Generator Deactivation Reliability Need. Further, this deficiency is also a Near-Term Reliability Need as it arises within three years following the 365-days following the 2026 Quarter 1 STAR Start Date.

Because permanent solutions to the Generator Deactivation Reliability need have not entered service yet or demonstrated their planned capabilities, Danskammer 1-4 cannot deactivate on August 1, 2026 and will be required to remain in-service until at least January 15, 2027, if permanent solutions are not available sooner. As such, Danskammer 1-4 will be an Interim Service Provider that is compensated under an Interim Service Provider rate commencing August 1, 2026. Further, following the issuance of this STAR, the NYISO will proceed with the steps to issuing a solution solicitation. This solicitation will also note available information from preliminary 2026 RNA analysis and 2026 Quarter 3 STAR study assumptions that impact the scope, scale, or nature of this need, which will be reviewed with stakeholders prior to issuing the solution solicitation.

Figure 1: Factors Affecting Lower Hudson Valley Transmission Security Margin



For the retirement of the Coxsackie GT, the NYISO does not identify a BPTF Generator Deactivation Reliability Need as the deficiency occurs just beyond the allowed period to retain generators impacted by the DEC Peaker Rule. However, Central Hudson does identify a non-BPTF Generator Deactivation Reliability Need. The identified need and the proposed solution are the same as that identified in the 2024 Quarter 1 STAR, where the retirement of this generator was first assessed. In its most recent local transmission plan update presented at the April 7, 2026 TPAS/ESPWG meeting, Central Hudson indicated that the STATCOM and capacitor bank at the New Baltimore 69 kV substation are expected to be in service by July 2026, with similar upgrades at the South Cairo 69 kV substation planned for March 2027. Until these projects are in service and have demonstrated their expected performance, the non-BPTF Generator Deactivation Reliability Need will persist. As such, Coxsackie GT must remain in-service until these upgrades are completed.

New York City

In the 2026 Quarter 1 STAR, the NYISO continued to observe a BPTF deficiency in New York City (Zone J) without the completion and energization of the future planned projects identified in the April 15, 2026 Short-Term Reliability Process Report. Following the start of this STAR, on May 13, 2026, CHPE entered commercial operation, but has yet to demonstrate its planned power capability.

With the continued operation of the Gowanus 2 & 3 and Narrows 1 & 2 barges[3] and without CHPE having demonstrated its planned power capability, the previously identified Short-Term Reliability Needs persist in New York City. Until planned projects are available, grid operators will likely rely on emergency operating procedures more often since the "just right" system condition in planning is often more optimistic than typical conditions experienced by operators. Emergency operating procedures include 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 Special Case Resources ("SCR") and Emergency Demand Response Programs ("EDRP'), public appeals to reduce demand, and voltage reduction. Capacity resource supplements could include emergency purchases and cutting operating reserves.[4]

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

[4] NYSRC Draft Policy 5-19: Procedure for Establishing New York Control Area Installed Capacity Requirements, issue on June 13, 2025

New York City BPTF Deficiency (2026 Quarter 2)

Summer Peak	2026	2027	2028	2029	2030
MW Deficiency	189	227	247	451-721	481-751
Duration (hours)	5	5	5	9	9
MWh	501	701	795	3,785-4,149	4,258-4,316

As observed in the 2026 Quarter 1 STAR, even with all projects identified to address the New York City Need entering service according to schedule and demonstrating their planned capabilities, without additional supply resources into this locality, reliability needs will likely develop just beyond the five-year study horizon of this STAR.

Long Island

In the 2026 Quarter 1 STAR, the NYISO continued to observe a BPTF Short-Term Reliability Need in the Long Island locality (first observed in the 2025 Quarter 3 STAR) without the completion and energization of the future planned projects identified in the April 15, 2026 Short-Term Reliability Process Report. As the IIFO of Far Rockaway GT1 ended on June 17, 2026, there are no generator deactivations to report on in this STAR and the NYISO continues to track the solutions discussed in the April 15, 2026 Short-Term Reliability Process Report. However, even with all planned projects entering service according to schedule and demonstrating their planning capabilities, the margins until the Propel NY project enter service are observed to be as narrow as 36 MW in summer 2027, with the largest margin at 103 MW in summer 2028.

Reliability Assessment

Included in this STAR is the generator deactivation assessment for the retirement of High Acres and Coxsackie GT. The NYISO performed a transmission security assessment of the BPTF. Central Hudson and Avangrid each performed a deactivation assessment to evaluate the reliability of the local non-BPTF system with the proposed deactivations in their respective service territories. Central Hudson identified 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.

Purpose

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

The first step in the STRP is the Short-Term Assessment of Reliability ("STAR"). STARs are performed quarterly to proactively address reliability needs that may arise within five years ("Short-Term Reliability Process Needs")[5] 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."[6] Should a Near-Term Reliability Need be identified in a STAR, the NYISO solicits and selects the solution to address the need. If a need arises beyond the first three years of the study period, the NYISO may choose to address the need within the STRP or, if time permits, through the long-term Reliability Planning Process.

This STAR report sets forth the 2026 Quarter 2 findings for the study period from the STAR Start Date (April 15, 2026) through April 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.[7]

[5] OATT Section 38.1 contains the tariff definition of a "Short-Term Reliability Process Need."
[6] OATT Section 38.1 contains the tariff definition of a "Near-Term Reliability Need." *See also*, OATT Section 38.3.6.
[7] For this STAR the NYISO utilized the Reliability Planning Process Manual, published July 11, 2022. Recent updates to the Reliability Planning Process Manual were approved by Stakeholders at the May 14, 2026 Operating Committee (here). The revisions documented in the Reliability Planning Process Manual will be reflected in the 2026 RNA as well as starting with the 2026 Quarter 3 STAR.

Assumptions

The NYISO evaluated the study period using the most recent Reliability Planning Process assumptions and data available as of April 14, 2026 (*i.e.,* the day before the April 15, 2026 Q2 STAR start date). In accordance with the Reliability Planning Process inclusion rules,[8] generation and transmission projects are included if they have met significant milestones such that there is a 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 May 6, 2026. The meeting materials are posted on the NYISO's website.[9]

Generation Assumptions

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

Generator Deactivation Notices

For this STAR, the deactivating generators included in this assessment are listed in Figure 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.[10] While the ICAP Ineligible Forced Outage ("IIFO") of Far Rockaway GT1(Zone K, 60.5 MW nameplate) was included in this assessment at the start of this STAR, on June 17, 2026 this unit returned to the market and is no longer in IIFO.

[8] *See* NYISO Reliability Planning Process Manual Section 3.
[9] Short-Term Assessment of Reliability: 2026 Q2 Key Study Assumptions, ESPWG/TPAS, May 6, 2026 (here)
[10] *See* https://www.nyiso.com/short-term-reliability-process then Generator Deactivation Notices/Planned Retirement Notices or Generator Deactivation Notices/IIFO Notifications.

Figure 2: 2026 Quarter 2 STAR Generator Deactivations

Owner/ Operator	Plant Name	PTID	Zone	Nameplate (MW)	Status	Proposed Deactivation/IIFO Date
WM Renewable Energy,LLC	High Acres	23767	C	9.6	R	7/15/2026
Central Hudson Gas & Electric Corp.	Coxsackie GT	23611	G	21.6	R	4/30/2027 (1)

Notes:

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

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

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

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

Figure 3: 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	2026 Q2
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	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)(11)	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)(11)	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)(11)	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		1174.3	1066.0	1348.8	945.5	1221.8		
	Prior to Summer 2025		725.1	656.3	857.1	610.8	786.6		
	Total		2011.4	1,814.9	2,326.2	1,634.3	2,120.6		

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 notifications 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 April 2, 2026 TPAS/ESPWG, Central Hudson presented in LTP update which continues to identify the retirement of the Coxsackie GT in April 2027.
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. On April 15, 2026 the NYISO issued a letter to the DEC designating the Gowanus 2 & 3 and Narrows 1 & 2 generators as needed to address ongoing reliability needs until May 1, 2029. Extending these generators through May 1, 2029 helps alleviate the identified deficiencies, but without additional supply resources, reliability needs will likely develop at the end of the five-year horizon or shortly after it. Subsequently, on April 16, 2026, AlphaGen withdrew their generator deactivation notice for these units.
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. Since much of the analysis in this STAR continues to utilize values from the 2025 Gold Book, the NYISO has continued to proactively account for the reduction in summer capability of 110 MW in New York City and 200 MW in Long Island. These MW reductions reflect the expected impacts to DMNC on resources impacted by the rule changes. For the purposes of the transmission security margin evaluations, the NYISO utilized the 2026 Gold Book released at the end of April 2026 which accounts for these reductions.

Demand Assumptions

This assessment primarily utilizes the demand forecasts from the 2025 Gold Book. For transmission security margin analysis, this STAR utilized the demand forecasts from the 2026 Gold Book under expected weather. 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. For this assessment, certain load projects in Zone K, which were included in the expected weather 2025 Gold Book forecasts, have been removed from the model based on status updates regarding these load projects provided by LIPA.

The Gold Book includes three coincident demand forecasts: Lower Demand, Baseline, and Higher Demand. Each of these forecasts contains differing inputs on economic, electrification, and large load assumptions, but the weather conditions are the same across each of these forecasts, 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 three demand 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 (or partial achievement) of New York's policy targets. However, the Higher Demand forecast does not include the full potential of peak-mitigating factors, such as managed EV charging and other flexible load and efficiency measures. The Higher Demand forecast assumes additional large load growth beyond that included in the baseline forecast. The Higher Demand econometric and EV and building electrification forecasts assume an increasing population and number of households over the duration of the forecast horizon, and stronger than expected economic growth.
- **Lower Demand –** The Lower Demand forecast assumes a slower EV adoption rate with a greater share of managed charging and a lower saturation of electric heating than the baseline forecast. Lower Demand forecast assumes reduced large load growth and weaker than expected economic growth relative to the baseline forecast.

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.

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

Figure 4: Lower Hudson Valley Demand Forecasts (2025 Gold Book)

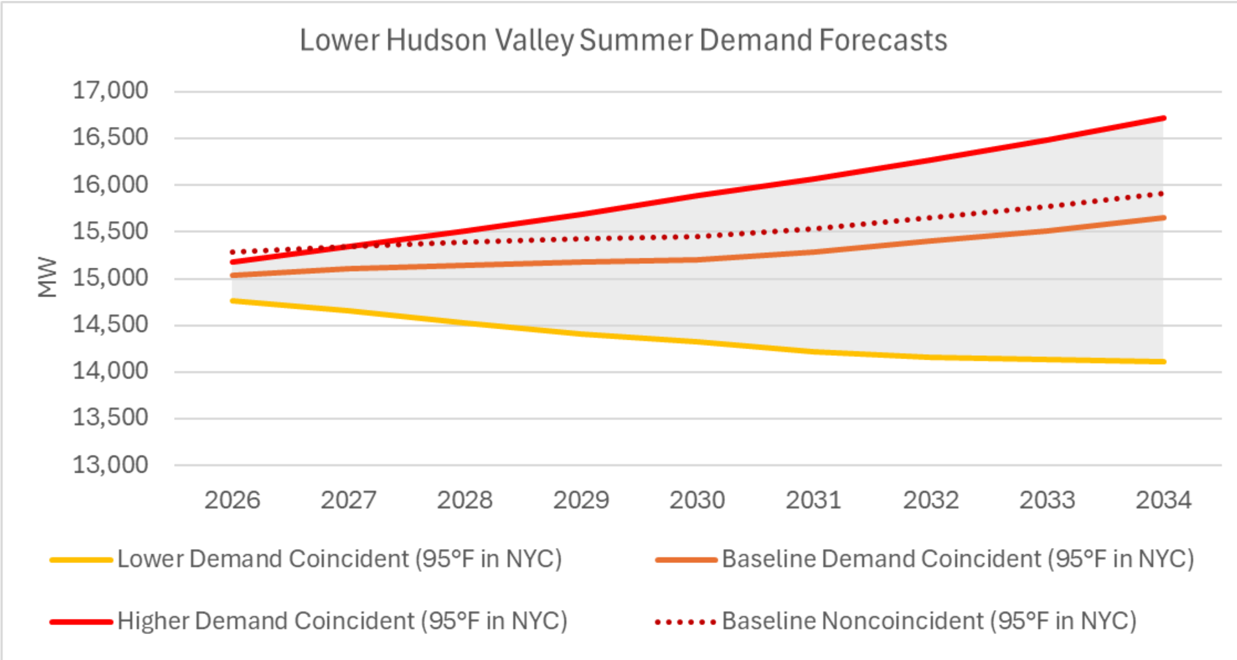


Figure 5: New York City Demand Forecasts (2025 Gold Book)

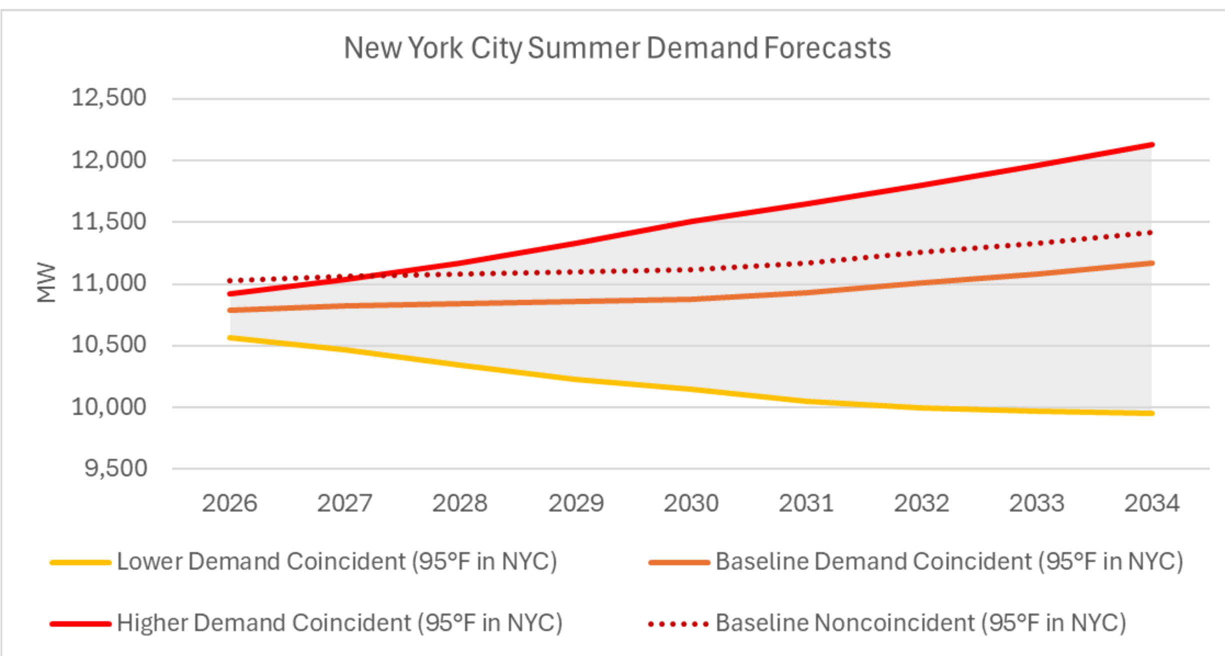


Figure 6: Long Island Demand Forecasts (2025 Gold Book)

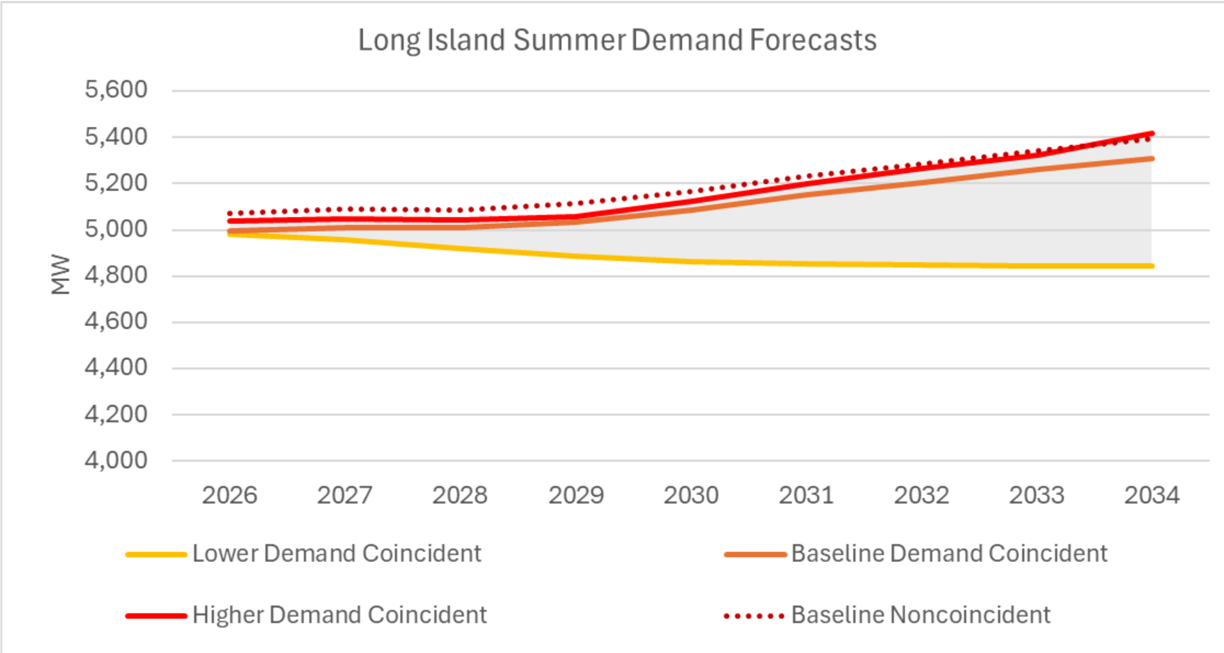
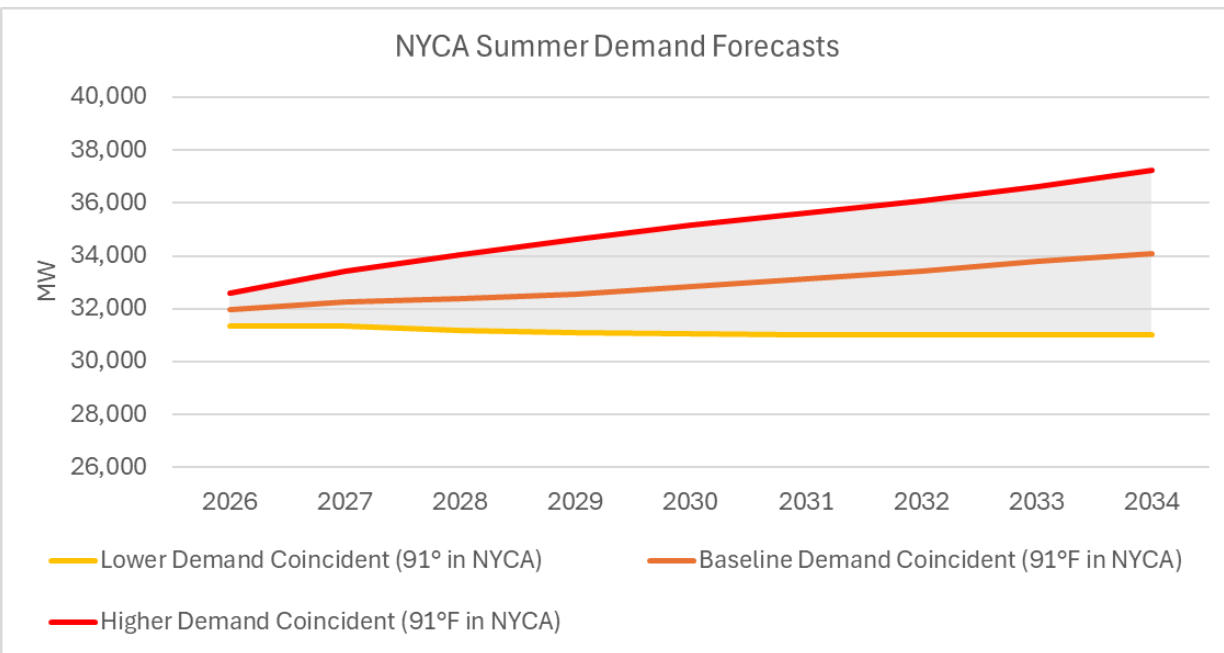


Figure 7: NYCA Demand Forecasts (2025 Gold Book)



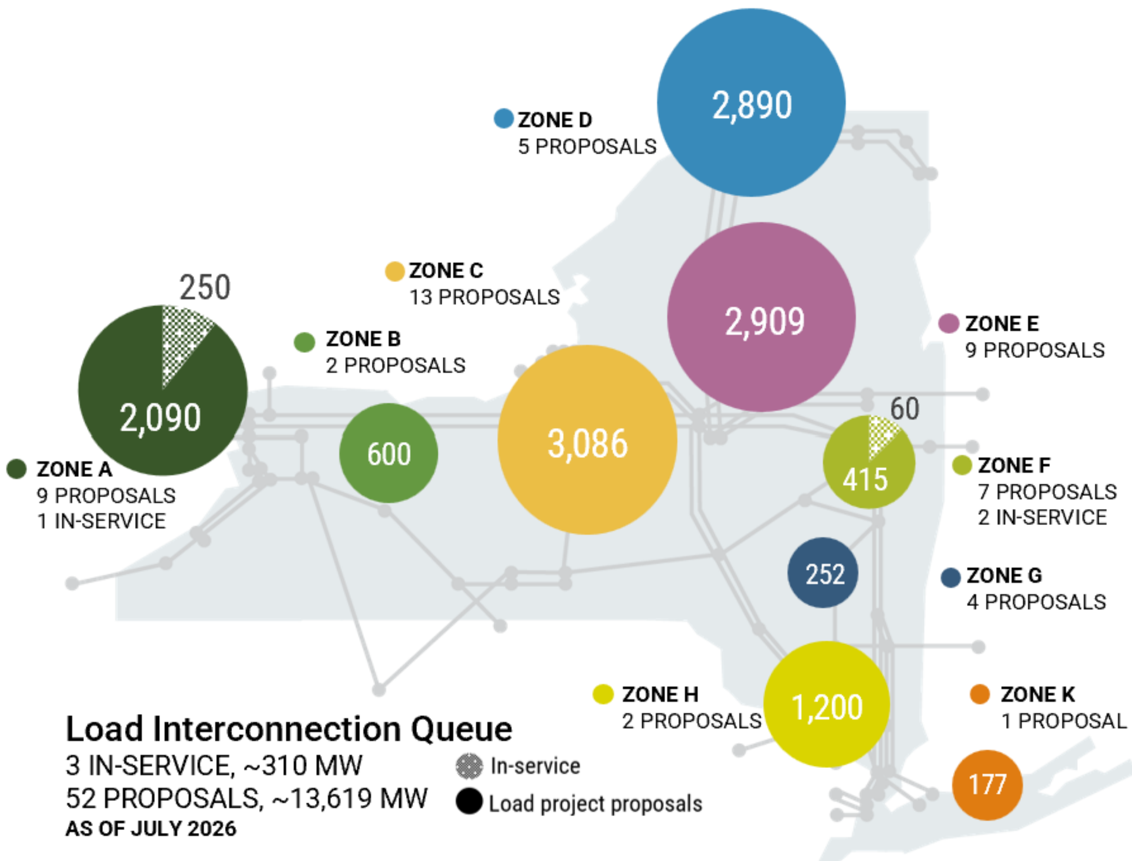
Large Load Assumptions

Due to economic development, and in anticipation of electrification efforts over the next two decades, numerous new large loads are expected to interconnect to the New York system. These large loads are concentrated in upstate New York. Most of these new loads consist of manufacturing facilities and data centers.

While only a few large load projects have been connected to the New York system in the past decade, the pace of new load interconnection requests[12] in New York has grown dramatically over the past several years. The NYISO currently (as of early July, 2026) has 53 projects requesting to interconnect for a combined total of over 13,620 MW of load. It is projected that over the next decade numerous additional manufacturing and data centers will enter commercial operation and begin consuming relatively large amounts of electricity. The large load projects included in the forecasts vary by forecast assumptions, with the high demand forecast including more than the baseline forecast. Figure 8 highlights the majority of large loads with active requests in the NYISO Interconnection Queue through early July 2026 (the figure does not include some of the more-recent load interconnection projects).

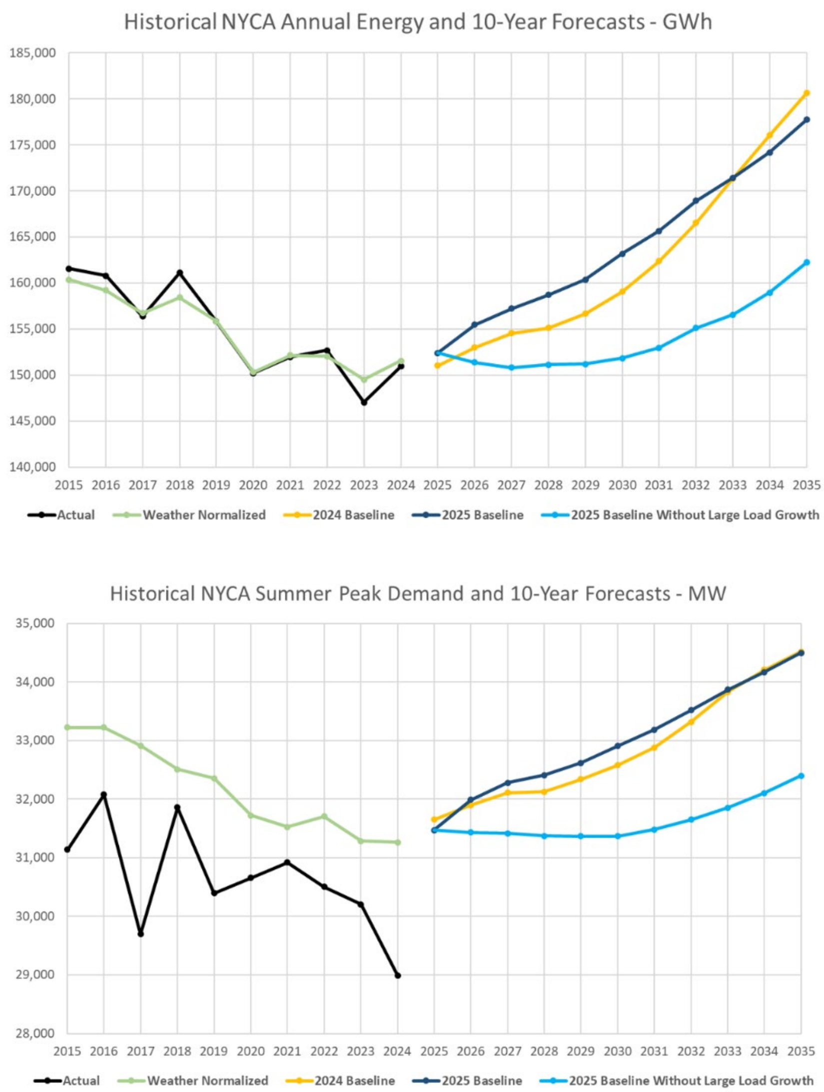
[12] Load interconnections that are subject to the NYISO's procedures include requests that are either (a) greater than 10 MW connecting a voltage level of 115 kV or above or (b) 80 MW or more connecting at a voltage level below 115 kV. Loads that do not meet one of the aforementioned criteria are handled through the Transmission Owners' processes.

Figure 8: Large Load Projects in the NYISO Interconnection Queue (July 2026)



The trend of rapid large load additions has manifested over the past few years and is observed across the country, with regional variations in the speed and types of loads. The impact of large load assumptions on the forecast is significant. Figure 9 below shows the baseline forecast with and without large load growth. The timing and level of large load interconnections will have major impacts on future load growth and system risk.

Figure 9: Large Load Impact on NYCA Baseline Load Forecast (2025 Gold Book)



Generation capacity in New York is secured to ensure that demand can be met, including new large loads added to the system. Generation capacity above and beyond the maximum load is necessary to ensure reliability and resource availability. This means that new large load interconnections will increase the requirement for generation capacity to a value greater than the load itself. The new large loads will have a significant impact on the need for new generating capacity. For additional details on this risk see section, "Reliability Margin Projections" in this report.

Some large load projects, however, do not always require the entire amount of the load to be served for all hours, or during peak system demand. The ability for large loads to be flexible in their usage is an extremely important consideration, particularly during times of peak system demand. Enabling load flexibility, or the ability to move load from times of greater system demand to times with lower demand or higher renewable energy production, can significantly reduce the generation capacity buildout required to serve new large loads.

While the interconnection queue identifies a significant amount of large load projects, only a portion of these is included in this assessment. Figure 27 provides a summary of the large loads included in this assessment on a zonal basis. Overall, by 2030, the study includes approximately 2 GW of large load projects.

One key assumption in this STAR is that cryptocurrency mining and hydrogen production large loads will be flexible during system peak demand conditions. This assumption, based on communications with load developers and recent operating experience, results in up to approximately 685 MW of large load reduction during the summer and winter peak periods by 2026.

The trend of large load development, and their operating characteristics, requires continuous monitoring as they come in service. The NYISO will continue to coordinate with load developers and Transmission Owners.

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 10: 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	
Station 23	Station 42	115	920	12/2026	
E13th Street		345/69	BK17	6/2027	

Notes

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

Proposed Transmission

Changes to firm projects in the Transmission Owners' Local Transmission Owner Plans

("LTPs") are captured in Section VII of the 2025 Gold Book. Following the start of this STAR, on May 13, 2026, Champlain Hudson Power Express ("CHPE") entered commercial operation, but has yet to demonstrate its planned power capability. As such, CHPE is not yet assumed available as an "existing resource" in this assessment, but remains a planned facility.

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.

Even with the continued operation of the Gowanus 2 & 3 and Narrows 1 & 2 barges[13] the NYISO continues to observe deficiencies within New York City throughout the STAR time horizon without the availability of permanent solutions, including CHPE. Operational experience from the Summer 2025 heatwaves, as well as the heatwave experienced in early July 2026, revealed how quickly tight resource margins and limited system flexibility can lead to stressed conditions even when overall resource adequacy and projected capacity margins appear sufficient. Current criteria measure resource adequacy only after assuming the full utilization of emergency operating procedures, effectively planning for operations to rely on extraordinary measures as routine practice. This approach leaves fewer tools available when real-time conditions deteriorate. Further, during the early July 2026 heatwave, the grid experienced about two-to-three times the generator outages in the New York City and Lower Hudson Valley regions compared to what is currently planned for, along with several transmission outages, placing the grid well beyond established planning criteria and practices.

As discussed in the 2026 Quarter 1 STAR, upon the withdrawal of the deactivation notices for the Gowanus and Narrows barges, the deficiencies in summer 2027 and 2028 within the Lower Hudson Valley would be addressed, but the deficiencies in 2029 and 2030 would continue to be observed and are exacerbated by the retirement of Danskammer 1-4. Just beyond the time horizon of this STAR, the margins in the Lower Hudson Valley are also impacted by the deactivation of the NYPA Small Plants. Danskammer 1-4 cannot deactivate on August 1, 2026 and will be required to remain in-service until at least January 15, 2027, if permanent solutions are not available sooner. Following the issuance of this STAR the NYISO will proceed to issue a solicitation for solutions to the Lower Hudson Valley deficiency.

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

On Long Island, until the Propel NY transmission project is in-service, the projected margins tighten to just 36 MW in summer 2027. The NYISO continues to track the solutions discussed in the April 15, 2026 Short-Term Reliability Process Report.

The Short-Term Reliability Process applies only to the first five years of the planning horizon. In the 2026 Quarter 1 STAR, additional details were provided for reliability margin projects for statewide adequacy and the locality transmission security margins. 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.

The findings in this section are based on the study assumptions presented to stakeholders at the May 6, 2026 TPAS/ESPWG meeting at the start of this STAR with the following additional changes:

- The ICAP IIFO of Far Rockaway GT1(Zone K, 60.5 MW nameplate) was included in the key study assumptions presentation to be evaluated in this assessment. However, on June 17, 2026 this unit returned to the market and is no longer in IIFO. As such, the results reported in this STAR have Far Rockaway GT1 returned to service.

The NYISO observes no BPTF Generator Deactivation Reliability Needs with the proposed retirement of High Acres or Coxsackie GT units. However, Central Hudson does find a non-BPTF Generator Deactivation Reliability Need associated with the retirement of Coxsackie GT.

Resource Adequacy Assessments

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

This assessment finds that the planned system through the study period meets the resource adequacy criterion.

Details about the resource adequacy study assumptions are provided in Appendix D**.**

Transmission Security Assessments

Transmission security is the ability of the power system to withstand disturbances, such as electric short circuits or unanticipated loss of system elements, and continue to supply and deliver electricity. The analysis for the transmission security assessment is conducted in accordance with NERC Reliability Standards, NPCC Transmission Design Criteria, and the NYSRC Reliability Rules. Transmission security is assessed deterministically with potential disturbances being applied without concern for the likelihood of the disturbance in the assessment. These disturbances (single-element and multiple-element contingencies) are categorized as the design criteria contingencies, which are explicitly defined in the reliability criteria. The impacts resulting from applying these design criteria contingencies are assessed to determine whether thermal loading, voltage or stability violations will occur. In addition, the NYISO performs a short circuit analysis to determine if the system can clear faulted facilities reliably under short circuit conditions. The NYISO's "Guideline for Fault Current Assessment"[14] 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.[15]

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. 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

[14] Attachment I of Transmission, Expansion, and Interconnection Manual.
[15] The RNA assumptions matrix is posted with the April 18, 2024 TPAS/ESPWG meeting materials, which are available here,

transfer criteria conditions for the Lower Hudson Valley, New York City, and Long Island localities.

For the purposes of identifying reliability needs on the BPTF using transmission security margin calculations, thermal generation MW capability is considered available based on NERC five-year class averages for the relevant type of unit.[16] 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 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

[16] The NERC five-year class average EFORd data is available here. Recent updates to the Reliability Planning Process Manual, including revisions to the thermal unit derating factor, were approved by Stakeholders at the May 14, 2026 Operating Committee (here). The revisions documented in the Reliability Planning Process Manual will be reflected in the 2026 RNA as well as starting with the 2026 Quarter 3 STAR.

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 non-BPTF short-circuit Generator Deactivation Reliability Need was 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).

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.

Lower Hudson Valley Transmission Security Margin

Consistent with the findings of the 2025 Quarter 3 and Quarter 4 STARs, the 2026 Quarter 1 STAR observed a Generator Deactivation Reliability Need. Primarily this need was driven by deficiencies in New York City and Long Island. However, the proposed retirement of Danskammer 1-4 evaluated in the 2026 Quarter 1 STAR exacerbated this deficiency. 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.

With the continued operation of the Gowanus and Narrows barges[17], other updates to key study assumptions in this Quarter 2 STAR, and with CHPE yet to demonstrate its planned capabilities, Figure 11 shows that the deficiencies within the Lower Hudson Valley continue to be observed until sufficient planned projects have entered service and demonstrated their capabilities. The magnitude and duration of the BPTF deficiency in the Lower Hudson Valley for this Quarter 2 STAR are:

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

<u>Lower Hudson Valley BPTF Deficiency</u>:

Summer Peak	2026	2027	2028	2029	2030
MW Deficiency	None	None	None	184-201	291-309
Duration (hours)	None	None	None	3-5	4-5
MWh	None	None	None	387-1,287	746-2,066

As discussed in the 2026 Quarter 1 STAR, due to the withdrawal of the deactivation notices for the Gowanus and Narrows barges, the deficiencies in summer 2027 and 2028 within the Lower Hudson Valley have been addressed, but the deficiencies in 2029 and 2030 would continue to be observed and are exacerbated by the retirement of Danskammer 1-4. These deficiencies are observed following the removal of the Gowanus and Narrows barges on May 1, 2029. Beyond 2030, should planned projects not enter service according to schedule and demonstrate their planned capabilities, Lower Hudson Valley would also be impacted by the unavailability of the NYPA Small Plants. The extension of the Gowanus and Narrows barges until May 1, 2029, in accordance with the DEC Peaker Rule, helps to address the Lower Hudson Valley deficiency whereas retaining Danskammer 1-4 would not help alleviate the ongoing New York City deficiency as the Danskammer units are outside of Zone J.

The range in the demand forecast driven by uncertainties in key assumptions, such as population and economic growth, energy efficiency, and installation of behind-the-meter renewable energy resources, and electric vehicle adoption and charging patterns as described in the Gold Book. The forecasted summer peak demand in the Lower Hudson Valley has a range of 348 MW in 2026 growing to 804 MW in 2030, primarily driven by assumptions in electrification of transportation and buildings.

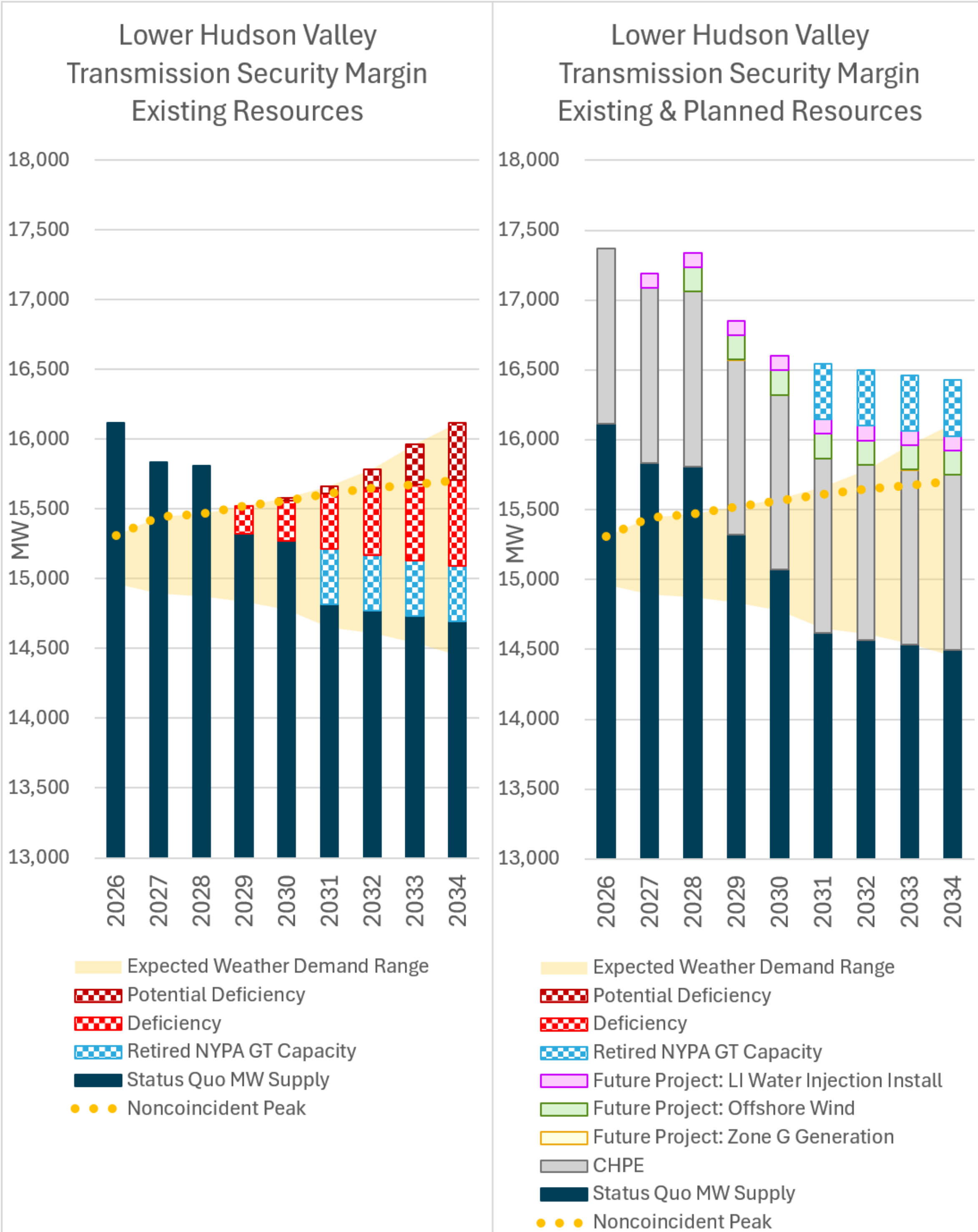
As the Lower Hudson Valley BPTF deficiency would be resolved in whole or in part by the retention of Danskammer 1-4, the Lower Hudson Valley deficiency is a Generator Deactivation Reliability Need. Further, this deficiency is also a Near-Term Reliability Need as it arises within 3-years following the 365-days following the 2026 Quarter 1 STAR Start Date.

Based on these findings, Danskammer 1-4 cannot deactivate on August 1, 2026 and will be required to remain in-service until at least January 15, 2027, if permanent solutions are not available sooner. As such, Danskammer 1-4 will be an Interim Service Provider that is compensated under an Interim Service Provider rate commencing August 1, 2026. Further, following the issuance of this STAR the NYISO will proceed with the steps to issuing a solution solicitation. This solicitation will also note available information from preliminary 2026 RNA analysis and 2026 Quarter 3 STAR assumptions that impact the scope, scale, or nature of this need, which will be reviewed with stakeholders prior to issuing the solution solicitation. Should sufficient solutions listed in Figure 12 and Figure 14 enter service and demonstrate their planned capabilities, the deficiency in the Lower Hudson Valley would be resolved.

For the retirement of the Coxsackie GT, the NYISO does not identify a BPTF Generator Deactivation Reliability Need as the deficiency occurs just beyond the ability to retain generators impacted by the DEC Peaker Rule.

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 and Long Island are completed and demonstrate their planned power capability to address the identified reliability needs, the deficiency in the Lower Hudson Valley 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 11: Factors Affecting Lower Hudson Valley Transmission Security Margin



New York City Transmission Security Margin

In the 2026 Quarter 1 STAR, the NYISO continued to observe a BPTF Generator Deactivation Reliability Needs in New York City (Zone J) without the completion and energization of the future planned projects identified in the April 15, 2026 Short-Term Reliability Process Report provided in Figure 12. Following the start of this STAR, on May 13, 2026, CHPE entered commercial operation, but has yet to demonstrate its planned power capability.

Figure 12: Projects Identified to Address New York City Need

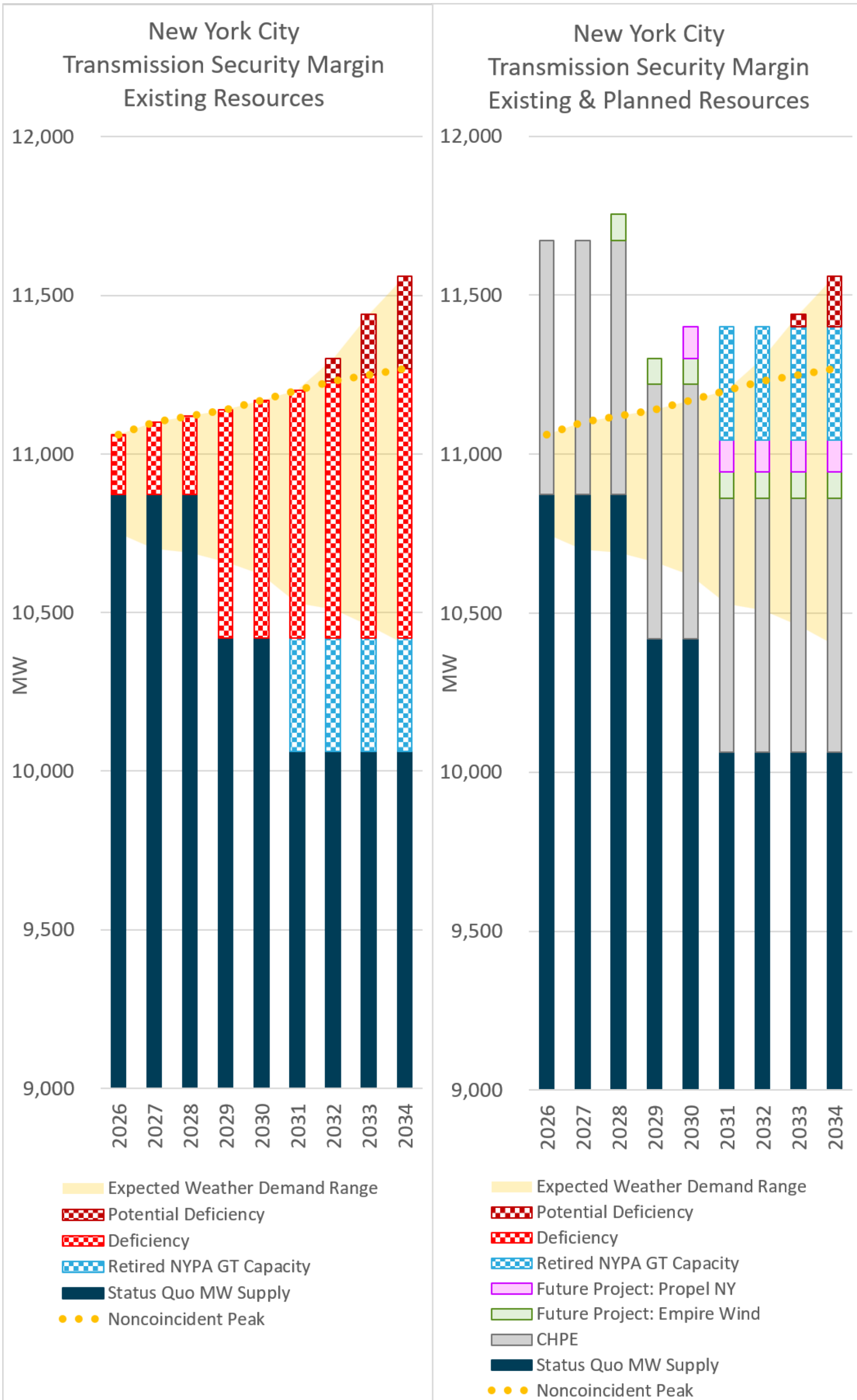
	Queue Pos.	Proposed Solution Developer	Project Name	Nameplate (MW)	Proposed In-Service
Proposed Solution	N/A	AlphaGen	Existing Gowanus & Narrows Retention	608	Existing
	Queue Pos.	**Developer/Interconnection Customer**	**Project Name**	**Nameplate (MW)**	**Proposed In-Service**
Other Projects (Permanent Solutions)	631/887	CHPE LLC	NS Power Express	1,250	Entered commercial operation but has yet to demonstrate its planned power capability
	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

With the continued operation of the Gowanus 2 & 3 and Narrows 1 & 2 barges[18] and without CHPE having demonstrated its capability, the previously identified BPTF Short-Term Reliability Process Need would persist throughout the planning horizon, but is not a new need. 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 capability to address the identified reliability needs, the previously identified BPTF and non-BPTF deficiencies would persist. Even with all projects identified to address the New York City Need entering service according to schedule and demonstrating their planned capabilities, without additional supply resources into this locality, reliability needs will likely develop just beyond the five-year study horizon of this STAR, as seen in Figure 13.

While the other planned projects listed in Figure 12 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.

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

Figure 13: Factors Affecting New York City Transmission Security Margin



In December 2025, the Public Service Commission directed Con Edison to develop a "NYC Reliability Contingency Plan" and to file a report identifying the specific reliability needs that Con Edison sees arising in its service territory, the dates of those needs, and the underlying assumptions and methodologies used in determining those needs.[19] In December 2025, the preliminary assessment identified a deficiency within the New York City 345/138 kV Transmission Load Area (TLA) of 250 MW over 4 hours (about 700 MWh). In January 2026, Con Edison updated these findings and is now projecting a deficiency to begin in 2032 at 125 MW. Con Edison updated its 2025 Local Transmission Plan (LTP) at the March 20, 2026 ESPWG/TPAS meeting based on the findings under this proceeding.[20]

Long Island Transmission Security Margin

In the 2026 Quarter 1 STAR, the NYISO continued to observe BPTF Generator Deactivation Reliability Needs in the Long Island locality which were first observed in the 2025 Quarter 2 STAR. These needs would persist without the completion and energization of the future planned projects listed in Figure 14 which were discussed in the April 15, 2026 Short-Term Reliability Process Report. As the IIFO of Far Rockaway GT1 ended on June 17, 2026, there are no generator deactivations to report on in this STAR and the NYISO continues to track these solutions.

Figure 14: Projects Identified to Address Long Island Need

Projects to Identifed to Address Long Island Need

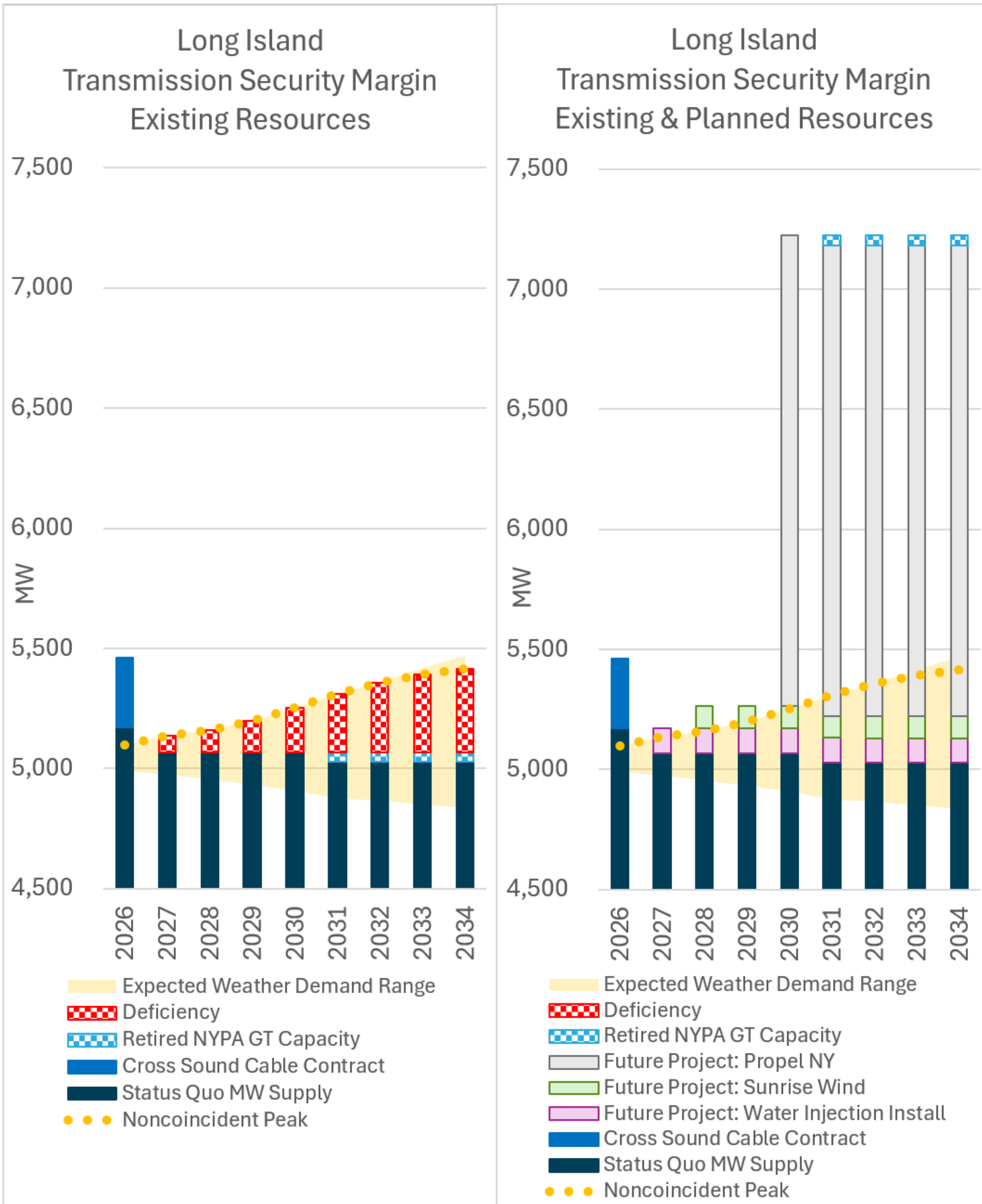
	Queue Pos.	Proposed Solution Developer	Project Name	Nameplate (MW)	Proposed In-Service
Proposed Solutions	N/A	PSEG-LI/LIPA	Shoreham 1 (water injection)	52.9	Existing, water injection by May 1, 2027
			Shoreham 2 (water injection)	18.6	
			Glenwood GT 3 (water injection)	55	
			Far Rockaway 1	60.5	Existing
			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

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.

[19] 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).

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

Figure 15: Factors Affecting Long Island Transmission Security Margin at the Start of this STAR



Local Non-BPTF Reliability Assessment

Central Hudson evaluated the impact of the Coxsackie GT retirement on its non-BPTF. Avangrid evaluated the impact of the High Acres retirement on its non-BPTF. The NYISO reviewed and verified the analysis performed by both Central Hudson and Avangrid.

Avangrid Non-BPTF Generator Deactivation Assessment

For this STAR, Avangrid performed a deactivation assessment to evaluate the reliability impact of the local non-BPTF system from the retirement of High Acres. Avangrid did not identify any Generator Deactivation Reliability Needs.

Central Hudson Non-BPTF Generator Deactivation Assessment

The proposed retirement of the Coxsackie GT was first evaluated in the 2024 Quarter 1 STAR with a proposed deactivation date of December 31, 2024. In that assessment, Central Hudson identified a non-BPTF Generator Deactivation Reliability Need. This Generator Deactivation Reliability Need was planned to be addressed by projects included in Central Hudson's Local Transmission Plan (LTP), with proposed in-service dates by December 31, 2025. Subsequent delays to the LTP project schedules shifted the expected in-service dates beyond those assumed in the 2024 Quarter 1 STAR. As a result, the Coxsackie GT did not complete the Generator Deactivation Process following that assessment. On April 14, 2026, Central Hudson submitted a new Generator Deactivation Notice for Coxsackie GT, proposing a new retirement date of April 30, 2027.

In this STAR, Central Hudson performed a deactivation assessment to evaluate the reliability of the local non-BPTF system for the retirement of the Coxsackie GT and has identified a non-BPTF Generator Deactivation Reliability Need. This need is the same as what was found by Central Hudson in the 2024 Quarter 1 STAR. In its most recent LTP update presented at the April 7, 2026 TPAS/ESPWG meeting, Central Hudson indicated that the STATCOM and capacitor bank at the New Baltimore 69 kV substation are expected to be in service by July 2026, with similar upgrades at the South Cairo 69 kV substation planned for March 2027. Until these projects are in service and have demonstrated their expected performance, the non-BPTF Generator Deactivation Reliability Needs will persist. As such, Coxsackie GT must remain in-service until these upgrades are completed.

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 2026 Quarter 1 STAR provided details of risks related to statewide adequacy as well as transmission security margins in each of the localities. 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 was estimated to be 525 MW. 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 over the 10-year horizon. 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, 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.[21] 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.

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 incorporate aging generation risk to better capture the likelihood of future resource unavailability and identify emerging reliability needs beyond the short-term 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 discussed the solutions submitted by Developers that it selected and other planned projects that meet the reliability planning process inclusion rules that help address reliability.[22]

Figure 16: Projects Identified to Address New York City Need

	Queue Pos.	Proposed Solution Developer	Project Name	Nameplate (MW)	Proposed In-Service
Proposed Solution	N/A	AlphaGen	Existing Gowanus & Narrows Retention	608	Existing
	Queue Pos.	**Developer/Interconnection Customer**	**Project Name**	**Nameplate (MW)**	**Proposed In-Service**
Other Projects (Permanent Solutions)	631/887	CHPE LLC	NS Power Express	1,250	Entered commercial operation but has yet to demonstrate its planned power capability
	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

[21] 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).

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

Figure 17: 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

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

In the April 15, 2026 Short-Term Reliability Process Report, the NYISO most recently designated the Gowanus 2 & 3 and Narrows 1 & 2 generators (608 MW nameplate)[23] as needed to address ongoing reliability needs until May 1, 2029, the maximum permissible permit extension date allowed, or until reliability needs are no longer identified in the NYISO's reliability assessments. AlphaGen, the owner, withdrew the generator deactivation notice for these generators on April 16, 2026. On May 13, 2026, CHPE entered commercial operation, but has yet to demonstrate its planned power capability.

As additional planned projects enter service, 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 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

[23] 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.

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.

Lower Hudson Valley

The Lower Hudson Valley BPTF deficiency identified in the 2026 Quarter 1 STAR was primarily driven by the deficiencies in New York City, but was also exacerbated by the proposed retirement of Danskammer units 1-4 and is also impacted by the deficiency on 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 planned solutions to address the Lower Hudson Valley BPTF Need in the short-term horizon.

Following the start of this STAR, on May 13, 2026, CHPE entered commercial operation. However, as CHPE has yet to demonstrate its planned power capability, Danskammer 1-4 cannot deactivate on August 1, 2026 and will be required to remain in-service until at least January 15, 2027, if permanent solutions are not available sooner. As such, Danskammer 1-4 will be an Interim Service Provider that is compensated under an Interim Service Provider rate commencing August 1, 2026. Further, following the issuance of this STAR, the NYISO will proceed with the steps to issuing a solution solicitation. This solicitation will also note available information from the preliminary 2026 RNA analysis and 2026 Quarter 3 STAR study assumptions that impact the scope, scale, or nature of this need, which will be reviewed with stakeholders prior to issuing the solution solicitation.

Conclusions

This STAR continues to find, as observed in prior STAR reports, that the Lower Hudson Valley locality is deficient beginning in 2029 and continuing through the remainder of the planning horizon. Primarily this need was driven by deficiencies in New York City and Long Island. However, the proposed retirement of Danskammer 1-4 evaluated in the 2026 Quarter 1 STAR exacerbated this deficiency. Until sufficient future planned projects enter service or CHPE demonstrates its planned capabilities, the Lower Hudson Valley is projected to be deficient by 184-201 MW over 3-5 hours (387-1,287 MWh) in 2029 growing to as large 291-309 MW over 4-5 hours (746-2,066 MWh) in 2030 during summer peak conditions.

This STAR also observed that New York City continues to be deficient without the operation of CHPE. Operational experience from the Summer 2025 heatwaves, as well as the heatwave experienced in early July 2026, revealed how quickly tight resource margins and limited system flexibility can lead to stressed conditions even when overall resource adequacy and projected capacity margins appear sufficient. Current criteria measure resource adequacy only after assuming the full utilization of emergency operating procedures, effectively planning for operations to rely on extraordinary measures as routine practice. This approach leaves fewer tools available when real-time conditions deteriorate. Further, during the early July 2026 heatwave, the grid experienced about two-to-three times the generator outages in the New York City and Lower Hudson Valley regions compared to what is currently planned for, along with several transmission outages, placing the grid well beyond established planning criteria and practices.

As the Lower Hudson Valley BPTF deficiency would be resolved in whole or in part by the retention of Danskammer 1-4, the Lower Hudson Valley deficiency is a Generator Deactivation Reliability Need. Further, this deficiency is also a Near-Term Reliability Need as it arises within 3-years following the 365-days following the 2026 Quarter 1 STAR Start Date. This need in the Lower Hudson Valley will be addressed through the Short-Term Reliability Process, as the needs cannot be timely addressed through the NYISO's Reliability Planning Process.

Danskammer 1-4 cannot deactivate on August 1, 2026 and will be required to remain in-service until at least January 15, 2027, if permanent solutions are not available sooner. As such, Danskammer 1-4 will be an Interim Service Provider that is compensated under an Interim Service Provider rate commencing August 1, 2026. Further, following the issuance of this STAR the NYISO will proceed with the steps to issuing a solution solicitation. This solicitation will also note available information from the preliminary 2026 RNA analysis and 2026 Quarter 3 STAR study assumptions that impact the scope, scale, or nature of this need, which will be reviewed with stakeholders prior to issuing the solution solicitation.

Central Hudson does identify a non-BPTF Generator Deactivation Reliability Need associated with the retirement of Coxsackie GT. In its most recent LTP update presented at the April 7, 2026 TPAS/ESPWG meeting, Central Hudson indicated that the STATCOM and capacitor bank at the New Baltimore 69 kV substation are expected to be in service by July 2026, with similar upgrades at the South Cairo 69 kV substation planned for March 2027. Until these projects are in service and have demonstrated their expected performance, the non-BPTF Generator Deactivation Reliability Need will persist. As such, Coxsackie GT must remain in-service until these upgrades are completed.

No Generator Deactivation Reliability Needs were observed with the retirement of High Acres.[24]

While planning assumptions indicate that identified deficiencies may be resolved once planned projects enter service and demonstrate their planned capabilities, recent operating experience continues to highlight that operators may encounter generator and transmission outage levels that exceed those assumed in planning assessments. Under these conditions, maintaining reliability increasingly depends on the availability of emergency operating procedures, including demand response programs, public appeals, voltage reduction, emergency purchases, and reductions to operating reserves. As planning margins become tighter, greater reliance is placed on these operating tools, leaving fewer actions available should system conditions deteriorate beyond expected levels. Continued progress toward permanent reliability solutions is therefore necessary not only to satisfy planning criteria, but also to preserve sufficient operating flexibility and resilience under real-world operating conditions.

[24] Consistent with Section 38.3.7 of the OATT, the earliest possible retirement date for WM Renewable Energy, LLC generator NEG Central High Acres is July 15, 2026. WM Renewable Energy, LLC must complete all required NYISO administrative processes and procedures prior to the retirement of its generator. See NYISO Technical Bulletin 185. The NYISO's determination in this Short-Term Reliability Process does not relieve WM Renewable Energy, LLC of any obligations it has with respect to its Generator's participation in the NYISO markets. If WM Renewable Energy, LLC rescinds its Generator Deactivation Notice or does not retire the unit within 730 days of April 15, 2026, then WM Renewable Energy, LLC 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.

Next Steps

The Short-Term Reliability Process Needs observed in the Lower Hudson Valley are Near-Term Reliability Needs and Generator Deactivation Reliability Needs. As a result, solutions will be solicited, evaluated, and addressed in accordance with the NYISO Short-Term Reliability Process. The needs may be addressed with generation solutions, demand-side solutions, and/or transmission solutions. The Lower Hudson Valley need arises within the Transmission District of several Transmission Owners including Central Hudson, Con Edison, NYSEG, and O&R; therefore, these transmission owners are the Responsible Transmission Owners for developing a regulated solution.

Following the 60-day solicitation for solutions, the NYISO will evaluate the proposed solutions and issue a Short-Term Reliability Process Report, which shall indicate NYISO's selection of a solution or combination of solutions, along with a reasoned explanation regarding why particular generation and/or transmission solutions were selected. If proposed solutions are not viable or sufficient to meet the identified reliability needs, interim solutions must be in place to keep the grid reliable. This solution selection process is designed to ensure that executing a Reliability Must Run (RMR) Agreement with generators is a last resort to addressing a reliability need.

The 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

Lower Hudson Valley Generator Deactivation Reliability Needs

Listed below is the BPTF Generator Deactivation Reliability Need in the Lower Hudson Valley locality in this STAR.

Lower Hudson Valley BPTF Deficiency:

Summer Peak	2026	2027	2028	2029	2030
MW Deficiency	None	None	None	184-201	291-309
Duration (hours)	None	None	None	3-5	4-5
MWh	None	None	None	387-1,287	746-2,066

Additionally, Central Hudson has identified a local non-BPTF Generator Deactivation Reliability Need associated with the Retirement of Coxsackie GT.

Appendix B: Short-Term Reliability Process Solution List

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

https://www.nyiso.com/documents/20142/19556596/SolutionStatusPosting-vFinal.pdf/

Appendix C: Summary of Study Assumptions

This assessment used the major assumptions included in the 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 ESPWG/TPAS meeting. Details regarding the 2026 Quarter 2 STAR study assumptions were reviewed with stakeholders at the May 6, 2026, joint ESPWG/ TPAS meeting. The meeting materials are posted on the NYISO's website.[25] The figures below (Figure 34, Figure 35, Figure 36, and Figure 37) summarize the changes to generation, load, and transmission.

Generation Assumptions

[25] Short-Term Assessment of Reliability: 2026 Q2 Key Study Assumptions, ESPWG/TPAS, May 6, 2026 (here). 2024 RNA Key Study Assumptions, ESPWG/TPAS, April 18, 2024 (here),

Figure 18: Completed Generator Deactivations

Owner/ Operator	Plant Name	Zone	Nameplate	CRIS (MW)		Capability (MW)		Status	Deactivation Date (2)	STAR Evaluation (3)
			(MW)	Summer	Winter	Summer	Winter			
International Paper Company	Ticonderoga (1)	F	9.0	7.6	7.5	9.5	9.8	I	5/1/2017	-
Helix Ravenswood, LLC	Ravenswood 2-4	J	42.9	39.8	50.6	30.7	41.6	I	4/1/2018	-
	Ravenswood 3-1	J	42.9	40.5	51.5	31.9	40.8	I	4/1/2018	-
	Ravenswood 3-2	J	42.9	38.1	48.5	29.4	40.3	I	4/1/2018	-
	Ravenswood 3-4	J	42.9	35.8	45.5	31.2	40.8	I	4/1/2018	-
Rockville Centre, Village of	Charles P Keller 07	K	2.0	2.0	2.0	1.9	1.9	R	3/1/2019	-
Exelon Generation Company LLC	Monroe Livingston	B	2.4	2.4	2.4	2.4	2.4	R	9/1/2019	-
Innovative Energy Systems, Inc.	Steuben County LF	C	3.2	3.2	3.2	3.2	3.2	R	9/1/2019	-
Consolidated Edison Co. of NY, Inc	Hudson Ave 4	J	16.3	13.9	18.2	14.0	16.3	R	9/10/2019	-
New York State Elec. & Gas Corp.	Auburn - State St	C	7.4	5.8	6.2	4.1	7.3	R	10/1/2019	-
Somerset Operating Company, LLC	Somerset	A	655.1	686.5	686.5	676.4	684.4	R	3/12/2020	-
Entergy Nuclear Power Marketing, LLC	Indian Point 2	H	1,299.0	1,026.5	1,026.5	1,011.5	1,029.4	R	4/30/2020	-
Cayuga Operating Company, LLC	Cayuga 1	C	155.3	154.1	154.1	151.0	152.0	R	6/4/2020	-
Entergy Nuclear Power Marketing, LLC	Indian Point 3	H	1,012.0	1,040.4	1,040.4	1,036.3	1,038.3	R	4/30/2021	-
Helix Ravenswood, LLC	Ravenswood GT 11	J	25.0	20.2	25.7	16.1	22.4	I	12/1/2021	2022 Q1
Helix Ravenswood, LLC	Ravenswood GT 1	J	18.6	8.8	11.5	7.7	11.1	I	1/1/2022	2022 Q1
Freeport Electric	Freeport 1-4	K	6.0	4.4	4.4	4.5	5.0	R	5/1/2022	-
Exelon Generation Company LLC	Madison County LF	E	1.6	1.6	1.6	1.6	1.6	I	4/1/2022	2022 Q2
Nassau Energy, LLC	Trigen CC	K	55.0	51.6	60.1	38.5	51.0	R	7/15/2022	2022 Q2
Consolidated Edison Co. of NY, Inc.	Hudson Ave 3	J	16.3	16.0	20.9	12.3	15.6	R	11/1/2022	2022 Q2
Consolidated Edison Co. of NY, Inc.	Hudson Ave 5	J	16.3	15.1	19.7	15.3	18.6	R	11/1/2022	2022 Q2
Astoria Generating Company, L.P.	Gowanus 1-1 through 1-8	J	160.0	138.7	181.1	133.1	182.2	R	11/1/2022	2022 Q2
Astoria Generating Company, L.P.	Gowanus 4-1 through 4-8	J	160.0	140.1	182.9	138.8	183.4	R	11/1/2022	2022 Q2
NRG Power Marketing LLC	Astoria GT 2-1	J	46.5	41.2	50.7	34.9	46.5	R	5/1/2023	2022 Q2
NRG Power Marketing LLC	Astoria GT 2-2	J	46.5	42.4	52.2	34.3	45.6	R	5/1/2023	2022 Q2
NRG Power Marketing LLC	Astoria GT 2-3	J	46.5	41.2	50.7	36.3	46.7	R	5/1/2023	2022 Q2
NRG Power Marketing LLC	Astoria GT 2-4	J	46.5	41.0	50.5	32.5	45.4	R	5/1/2023	2022 Q2
NRG Power Marketing LLC	Astoria GT 3-1	J	46.5	41.2	50.7	34.6	45.0	R	5/1/2023	2022 Q2
NRG Power Marketing LLC	Astoria GT 3-2	J	46.5	43.5	53.5	35.7	45.3	R	5/1/2023	2022 Q2
NRG Power Marketing LLC	Astoria GT 3-3	J	46.5	43.0	52.9	33.9	44.6	R	5/1/2023	2022 Q2
NRG Power Marketing LLC	Astoria GT 3-4	J	46.5	43.0	52.9	34.9	45.5	R	5/1/2023	2022 Q2
NRG Power Marketing LLC	Astoria GT 4-1	J	46.5	42.6	52.4	33.6	43.8	R	5/1/2023	2022 Q2
NRG Power Marketing LLC	Astoria GT 4-2	J	46.5	41.4	51.0	34.3	44.3	R	5/1/2023	2022 Q2
NRG Power Marketing LLC	Astoria GT 4-3	J	46.5	41.1	50.6	35.4	46.4	R	5/1/2023	2022 Q2
NRG Power Marketing LLC	Astoria GT 4-4	J	46.5	42.8	52.7	35.2	44.1	R	5/1/2023	2022 Q2
Helix Ravenswood, LLC	Ravenswood 10	J	25.0	21.2	27.0	16.1	20.3	R	5/1/2023	2022 Q3
Helix Ravenswood, LLC	Ravenswood 01	J	18.6	8.8	11.5	7.7	11.1	R	10/14/2023	2023 Q3
Helix Ravenswood, LLC	Ravenswood 11	J	25.0	20.2	25.7	16.1	22.4	R	10/14/2023	2023 Q3
Astoria Generating Company, L.P.	Gowanus 3-6	J	20.0	17.6	23.0	16.4	20.4	I	4/1/2025	2025 Q2
Astoria Generating Company, L.P.	Narrows 2-1 and 2-7	J	44.0	40.1	52.3	37.9	48.8	I	5/1/2025	2025 Q2
Consolidated Edison Co. of NY, Inc.	59 St. GT 1 (4)	J	17.1	15.4	20.1	13.9	17.4	R	5/1/2025	-
Western New York Wind Corp	Western NY Wind Power	B	6.6	0.0	0.0	0.0	0.0	R	10/15/2023	2023 Q3
Central Hudson Gas & Electric Corp.	South Cairo GT	G	21.6	19.8	25.9	18.7	23.1	R	3/31/2024	2023 Q4
Cubit Power One Inc.	Arthur Kill Cogen	J	11.1	11.1	11.1	11.1	10.2	I	3/2/2024	2024 Q2
NRG Power Marketing, LLC	Arthur Kill GT 1 (4)	J	20	16.5	21.6	12.4	16.1	R	5/1/2025	-
Eastern Generation, LLC	Astoria GT 01	J	16	15.7	20.5	13.8	17.6	R	5/1/2025	2024 Q3
Madison Windpower, LLC	Madison Windpower	E	11.6	11.5	11.5	11.6	11.6	R	9/5/2025	2025 Q1
Casella Waste Systems, Inc	Hyland LFGE	B	4.8	4.8	4.8	4.8	4.8	I	6/17/2025	2025 Q3
Relevate ReDev Borrower II LLC	Dahowa Hydro	F	12.3	10.5	10.5	12.3	12.3	I	9/1/2025	2025 Q4
MPH Cross Island Power, LLC	Pinelawn Power 1	K	82	78.0	78.0	73.6	76.5	I	6/1/2026	2025 Q3
		Total	4,685.8	4,288.7	4,615.3	4,083.4	4,455.2			

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 19: Proposed Deactivations

Owner/ Operator	Plant Name (1)	Zone	Nameplate (MW)	CRIS (MW)		Capability (MW)		Status	Deactivation date (2)	STAR Evaluation
				Summer	Winter	Summer	Winter			
Central Hudson Gas & Electric Corp.	Coxsackie GT (3)	G	21.6	21.6	26.0	19.7	25.2	R	4/30/2027	2026 Q2
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
WM Renewable Energy,LLC	High Acres	C	9.6	9.6	9.6	9.6	9.6	R	7/15/2026	2026 Q2
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	1231.7	1148.7	1342.0	1099.7	1264.7			

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. At the April 2, 2026 TPAS/ESPWG, Central Hudson presented in LTP update which continues to identify the retirement of the Coxsackie GT in April 2027.

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

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

Figure 20: 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 21: Small Generation Additions

Proposed Project Inclusion: Small Generation						
Queue	**Project Name**	**MW**	**Type**	**Zone**	**Proposed COD Date**	**Included in Prior STAR**
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	Jan-27	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	Dec-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
865	Flat Hill Solar	20	S	E	Aug-27	Yes
885	Grassy Knoll Solar	20	S	E	May-28	Yes
1003	Clear View Solar	20	S	C	Aug-26	Yes
1015	Somers Solar, LLC	20	S	F	Dec-26	Yes
1047	Millers Grove Solar	20	S	E	Mar-28	Yes

*All projects have CRIS.

Demand Assumptions

The 2026 Quarter 2 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. For the transmission security margin assessment, the NYISO utilized forecast information from the 2026 Gold Book.

Figure 22: Summer Coincident Peak Demand Forecasts (2025 Gold Book)

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 23: Winter Coincident Peak Demand Forecasts (2025 Gold Book)

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 24: Annual Energy Forecasts (2025 Gold Book)

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 25: Summer Non-Coincident Peak Demand Forecast (2025 Gold Book)

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 26: Winter Non-Coincident Peak Demand Forecast (2025 Gold Book)

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 27: Large Load Demand Forecast (2025 Gold Book)

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	5	1,329	685
2028	335	11	288	647	41	40	104	34	1,500	685
2029	335	11	442	651	54	40	107	78	1,718	685
2030	335	11	653	651	70	40	110	135	2,005	685

Large Loads Winter Peak Forecasts (MW)

Zone	A	B	C	D	E	F	G	K	NYCA Total	Flexible Total
2024-25	250	5	0	177	14	0	32	0	478	416
2025-26	335	11	72	582	23	0	72	0	1,095	685
2026-27	335	11	168	647	36	40	93	17	1,347	685
2027-28	335	11	288	651	48	40	104	90	1,567	685
2028-29	335	11	442	651	62	40	107	174	1,822	685
2029-30	335	11	653	651	70	40	110	236	2,106	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 28: 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	
Station 23	Station 42	115	920	12/2026	
E13th Street		345/69	BK17	6/2027	

Notes

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

Figure 29: 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 30: 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 31: 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

2026 Q2 STAR MARS Assumptions Matrix

	Parameter	2024 RNA Base Cases Key Assumptions (2024 Gold Book)	2025 RPP, 2025 Q3, Q4 STAR 2026 Q1, Q2 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 • May 6, 2026 Q2 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)	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])*

	The LFU model captures the 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

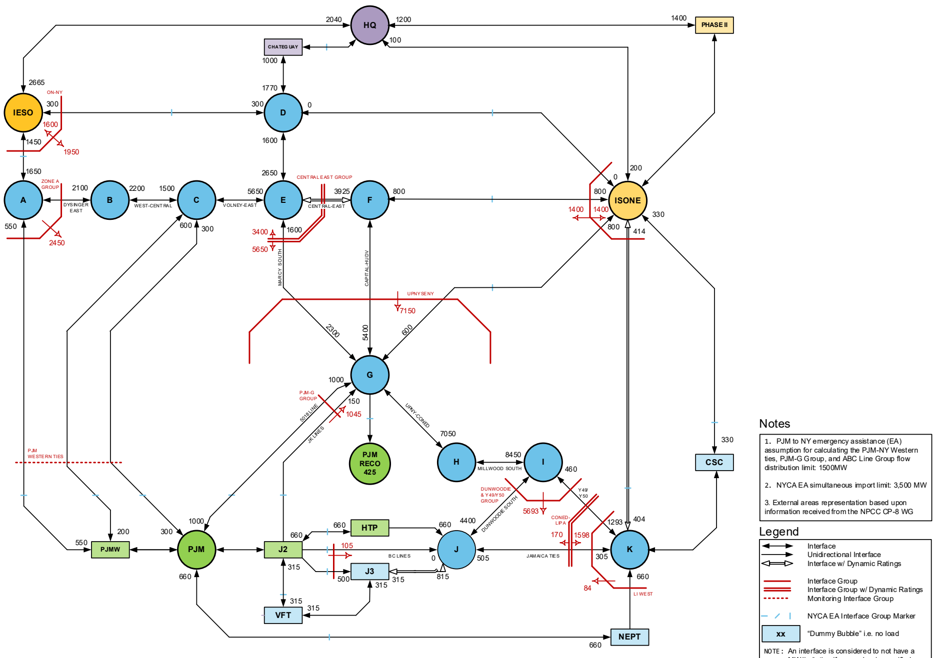
		system to determine the number of weeks on maintenance for each thermal unit.	system to determine the number of weeks on maintenance for each thermal unit.
8	Summer Maintenance	None	None
9	Combustion Turbine Derates	Derate based on temperature correction curves. Thermal derates are based on a ratio of 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.**

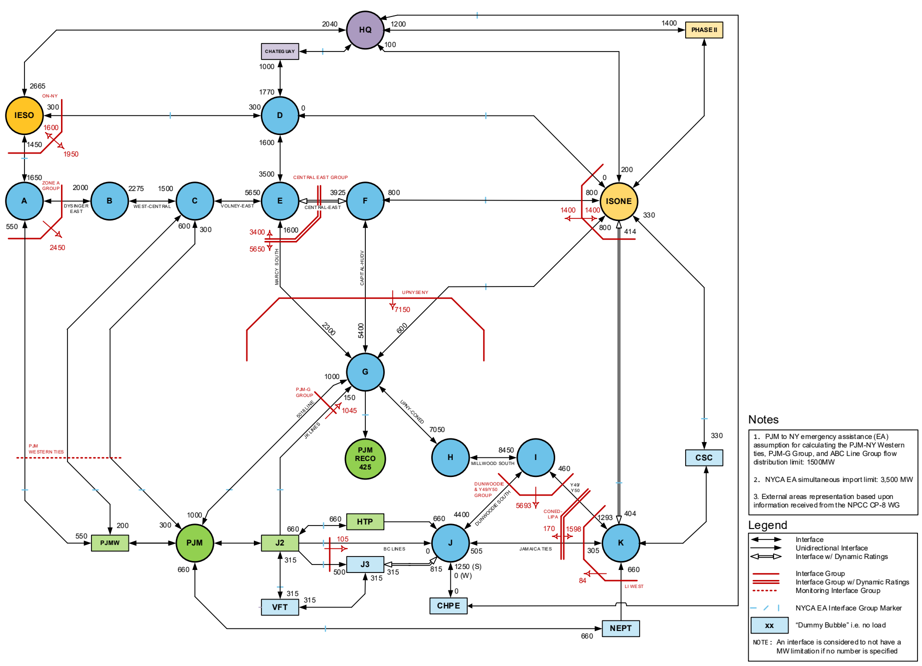
2	New Transmission	Based on TO-provided firm plans via Gold Book/LTP 2024 processes) and proposed merchant transmission and public policy facilities meeting the RNA Base Case inclusion rules.	Based on TO-provided firm plans (via Gold Book/LTP 2025 processes) and proposed merchant transmission and public 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[26]



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)

26 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 2026 Gold Book and the projects that meet the reliability planning inclusion rules for the 2026 Quarter 2 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 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.[27] 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.[28]

[27] 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.
[28] 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 32: 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)	37,265	38,757	41,487	41,107	41,107	40,664	40,664	40,664	40,664
B	NYCA Generation Unavailability (2)	(6,241)	(7,636)	(10,104)	(10,164)	(10,164)	(10,118)	(10,118)	(10,143)	(10,143)
C	Temperature Based Generation Derates	0	0	0	0	0	0	0	0	0
D	External Area Interchanges (3)	3,208	2,919	2,919	2,919	2,919	2,919	2,919	2,919	2,919
E	**Total Resources (A+B+C+D)**	34,231	34,040	34,303	33,861	33,861	33,464	33,464	33,439	33,439
F	Demand Forecast (5)	(30,903)	(31,205)	(31,305)	(31,395)	(31,575)	(31,745)	(31,885)	(32,085)	(32,245)
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)**	(32,213)	(32,515)	(32,615)	(32,705)	(32,885)	(33,055)	(33,195)	(33,395)	(33,555)
I	**Statewide System Margin (E+H)**	2,018	1,525	1,688	1,156	976	409	269	44	(116)
J	Higher Demand Impact	(72)	(340)	(600)	(1,220)	(1,490)	(1,810)	(2,150)	(2,520)	(2,770)
K	**Higher Demand Statewide System Margin (I+J)**	1,946	1,185	1,088	(64)	(514)	(1,401)	(1,881)	(2,476)	(2,886)
L	SCRs (6), (7)	804	804	804	804	804	804	804	804	804
M	**Statewide System Margin with SCR (K+L)**	2,749	1,988	1,891	740	290	(597)	(1,077)	(1,672)	(2,082)
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)**	1,439	678	581	(570)	(1,020)	(1,907)	(2,387)	(2,982)	(3,392)

Notes:

1. Reflects the 2026 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 (2026 Gold Book Table I-9a) and solar PV peak reductions (2026 Gold Book Table I-9c). Derates for run-of-river hydro are included 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).

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 2026 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 33: 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)	40,406	43,052	43,817	43,165	42,708	42,708	42,708	42,708	42,708
B	NYCA Generation Unavailability (2)	(6,776)	(9,068)	(9,833)	(9,833)	(9,833)	(9,833)	(9,833)	(9,833)	(9,833)
C	Unavailability of Non-Firm Gas (6)	(5,875)	(5,875)	(5,875)	(5,875)	(5,418)	(5,418)	(5,418)	(5,418)	(5,418)
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)**	28,603	28,668	28,668	28,017	28,017	28,017	28,017	28,017	28,017
G	Demand Forecast (5)	(24,620)	(25,110)	(25,410)	(25,880)	(26,310)	(26,690)	(27,120)	(27,550)	(28,000)
H	Large Load Flexibility	675	675	675	675	675	675	675	675	675
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)**	(25,255)	(25,745)	(26,045)	(26,515)	(26,945)	(27,325)	(27,755)	(28,185)	(28,635)
K	**Statewide System Margin (F+J)**	3,348	2,923	2,623	1,502	1,072	692	262	(168)	(618)
L	SCRs (7), (8)	721	721	721	721	721	721	721	721	721
M	**Statewide System Margin with SCR (K+L)**	4,069	3,644	3,344	2,223	1,793	1,413	983	553	103
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)**	2,759	2,334	2,034	913	483	103	(327)	(757)	(1,207)

Notes:

1. Reflects the 2026 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).
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 2026 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 34: 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)	37,265	38,757	41,487	41,107	41,107	40,664	40,664	40,664	40,664
B	NYCA Generation Unavailability (2)	(6,241)	(7,636)	(10,104)	(10,164)	(10,164)	(10,118)	(10,118)	(10,143)	(10,143)
C	Temperature Based Generation Derates	0	0	0	0	0	0	0	0	0
D	External Area Interchanges (3)	3,208	2,919	2,919	2,919	2,919	2,919	2,919	2,919	2,919
E	**Total Resources (A+B+C+D)**	34,231	34,040	34,303	33,861	33,861	33,464	33,464	33,439	33,439
F	Demand Forecast (5)	(31,578)	(31,880)	(31,980)	(32,070)	(32,250)	(32,420)	(32,560)	(32,760)	(32,920)
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)**	(32,888)	(33,190)	(33,290)	(33,380)	(33,560)	(33,730)	(33,870)	(34,070)	(34,230)
I	**Statewide System Margin (E+H)**	1,343	850	1,013	481	301	(266)	(406)	(631)	(791)
J	Higher Demand Impact	(72)	(340)	(600)	(1,220)	(1,490)	(1,810)	(2,150)	(2,520)	(2,770)
K	**Higher Demand Statewide System Margin (I+J)**	1,271	510	413	(739)	(1,189)	(2,076)	(2,556)	(3,151)	(3,561)
L	SCRs (6), (7)	804	804	804	804	804	804	804	804	804
M	**Statewide System Margin with SCR (K+L)**	2,074	1,313	1,216	65	(385)	(1,272)	(1,752)	(2,347)	(2,757)
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)**	764	3	(94)	(1,245)	(1,695)	(2,582)	(3,062)	(3,657)	(4,067)

Notes:

1. Reflects the 2026 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 (2026 Gold Book Table I-9a) and solar PV peak reductions (2026 Gold Book Table I-9c). Derates for run-of-river hydro are included 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).
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 2026 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 35: 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)	40,406	43,052	43,817	43,165	42,708	42,708	42,708	42,708	42,708
B	NYCA Generation Unavailability (2)	(6,776)	(9,068)	(9,833)	(9,833)	(9,833)	(9,833)	(9,833)	(9,833)	(9,833)
C	Unavailability of Non-Firm Gas (6)	(5,875)	(5,875)	(5,875)	(5,875)	(5,418)	(5,418)	(5,418)	(5,418)	(5,418)
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)**	28,603	28,668	28,668	28,017	28,017	28,017	28,017	28,017	28,017
G	Demand Forecast (5)	(24,620)	(25,110)	(25,410)	(25,880)	(26,310)	(26,690)	(27,120)	(27,550)	(28,000)
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)**	(25,930)	(26,420)	(26,720)	(27,190)	(27,620)	(28,000)	(28,430)	(28,860)	(29,310)
K	**Statewide System Margin (F+J)**	2,673	2,248	1,948	827	397	17	(413)	(843)	(1,293)
L	SCRs (7), (8)	721	721	721	721	721	721	721	721	721
M	**Statewide System Margin with SCR (K+L)**	3,394	2,969	2,669	1,548	1,118	738	308	(122)	(572)
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)**	2,084	1,659	1,359	238	(192)	(572)	(1,002)	(1,432)	(1,882)

Notes:

1. Reflects the 2026 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).
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 2026 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 36: Summer Statewide System Margin Calculation – Status Quo System, Flexible Large Loads Off

Line	Item	Summer Peak - Expected Summer Weather, Normal Transfer Criteria (MW)								
		2026	2027	2028	2029	2030	2031	2032	2033	2034
A	NYCA Generation (1)	37,148	37,012	37,012	36,507	36,507	36,064	36,064	36,064	36,064
B	NYCA Generation Unavailability (2)	(6,130)	(6,123)	(6,123)	(6,070)	(6,070)	(6,025)	(6,025)	(6,031)	(6,031)
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)**	32,975	32,558	32,558	32,106	32,106	31,708	31,708	31,702	31,702
F	Demand Forecast (5)	(30,903)	(31,205)	(31,305)	(31,395)	(31,575)	(31,745)	(31,885)	(32,085)	(32,245)
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)**	(32,213)	(32,515)	(32,615)	(32,705)	(32,885)	(33,055)	(33,195)	(33,395)	(33,555)
I	**Statewide System Margin (E+H)**	762	43	(57)	(599)	(779)	(1,347)	(1,487)	(1,693)	(1,853)
J	Higher Demand Impact	(72)	(340)	(600)	(1,220)	(1,490)	(1,810)	(2,150)	(2,520)	(2,770)
K	**Higher Demand Statewide System Margin (I+J)**	690	(297)	(657)	(1,819)	(2,269)	(3,157)	(3,637)	(4,213)	(4,623)
L	SCRs (6), (7)	804	804	804	804	804	804	804	804	804
M	**Statewide System Margin with SCR (K+L)**	1,493	507	147	(1,016)	(1,466)	(2,354)	(2,834)	(3,409)	(3,819)
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)**	183	(803)	(1,163)	(2,326)	(2,776)	(3,664)	(4,144)	(4,719)	(5,129)

Notes:

1. Reflects the 2026 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).
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
4. For informational purposes.
5. Reflects the 2026 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 37: Winter Statewide System Margin Calculation – Status Quo System

Line	Item	Winter Peak - Baseline Expected Winter Weather, Normal Transfer Criteria (MW)								
		2026-27	2027-28	2028-29	2029-30	2030-31	2031-32	2032-33	2033-34	2034-35
A	NYCA Generation (1)	39,357	39,192	39,192	38,540	38,082	38,082	38,082	38,082	38,082
B	NYCA Generation Unavailability (2)	(5,795)	(5,781)	(5,781)	(5,781)	(5,781)	(5,781)	(5,781)	(5,781)	(5,781)
C	Unavailability of Non-Firm Gas (6)	(5,875)	(5,875)	(5,875)	(5,875)	(5,418)	(5,418)	(5,418)	(5,418)	(5,418)
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)**	28,535	28,096	28,096	27,444	27,444	27,444	27,444	27,444	27,444
G	Demand Forecast (5)	(24,620)	(25,110)	(25,410)	(25,880)	(26,310)	(26,690)	(27,120)	(27,550)	(28,000)
H	Large Load Flexibility	675	675	675	675	675	675	675	675	675
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)**	(25,255)	(25,745)	(26,045)	(26,515)	(26,945)	(27,325)	(27,755)	(28,185)	(28,635)
K	**Statewide System Margin (F+J)**	3,280	2,351	2,051	929	499	119	(311)	(741)	(1,191)
L	SCRs (7), (8)	721	721	721	721	721	721	721	721	721
M	**Statewide System Margin with SCR (K+L)**	4,001	3,071	2,771	1,649	1,219	839	409	(21)	(471)
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)**	2,691	1,761	1,461	339	(91)	(471)	(901)	(1,331)	(1,781)

Notes:

1. Reflects the 2026 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).
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 2026 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).

Figures below 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. Figures are included for both the status quo system and the as-planned system.

Figure 38: 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	(15,042)	(15,171)	(15,194)	(15,250)	(15,289)	(15,334)	(15,372)	(15,399)	(15,430)
B	RECO Demand	(407)	(407)	(407)	(404)	(404)	(404)	(404)	(404)	(417)
C	**Total Demand (A+B)**	(15,449)	(15,578)	(15,601)	(15,654)	(15,693)	(15,738)	(15,776)	(15,803)	(15,847)
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	(219)	(244)	(282)	(333)	(431)	(477)	(512)	(535)
G	**Total SENY AC Import (D+E+F)**	4,736	4,470	4,445	4,407	4,356	4,258	4,212	4,177	4,154
H	Loss of Source Contingency	0	0	0	0	0	0	0	0	0
I	**Resource Need (C+G+H)**	(10,713)	(11,108)	(11,156)	(11,247)	(11,337)	(11,480)	(11,564)	(11,626)	(11,693)
J	G-J Generation (1)	12,752	12,732	12,732	12,227	12,227	11,829	11,829	11,829	11,829
K	G-J Generation Unavailability (2)	(1,103)	(1,101)	(1,101)	(1,048)	(1,048)	(1,007)	(1,007)	(1,007)	(1,007)
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)**	11,789	11,771	11,771	11,319	11,319	10,962	10,962	10,962	10,962
O	**Transmission Security Margin (I+N)**	1,076	664	616	72	(18)	(518)	(603)	(665)	(732)
P	Higher Demand Impact	(49)	(143)	(182)	(256)	(291)	(329)	(413)	(562)	(685)
Q	**Higher Demand Transmission Security Margin (O+P)**	1,027	521	434	(184)	(309)	(847)	(1,016)	(1,227)	(1,417)
R	Noncoincident Peak Demand Impact	(270)	(272)	(272)	(273)	(273)	(275)	(275)	(276)	(276)
S	**Noncoincident Peak Transmission Security Margin (O+R)**	806	392	344	(201)	(291)	(793)	(878)	(941)	(1,008)
T	2026 NYCA ICAP Market Peak Forecast Impact	(270)	-	-	-	-	-	-	-	-
U	**2026 NYCA ICAP Market Peak Forecast Margin (O+T)**	806	-	-	-	-	-	-	-	-

Notes:

1. Reflects the 2026 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).

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 39: 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	(15,042)	(15,171)	(15,194)	(15,250)	(15,289)	(15,334)	(15,372)	(15,399)	(15,430)
B	RECO Demand	(407)	(407)	(407)	(404)	(404)	(404)	(404)	(404)	(417)
C	**Total Demand (A+B)**	(15,449)	(15,578)	(15,601)	(15,654)	(15,693)	(15,738)	(15,776)	(15,803)	(15,847)
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	(115)	(48)	(86)	(137)	(234)	(280)	(315)	(338)
G	**Total SENY AC Import (D+E+F)**	4,736	4,574	4,641	4,603	4,352	4,255	4,209	4,174	4,151
H	Loss of Source Contingency	0	0	0	0	0	0	0	0	0
I	**Resource Need (C+G+H)**	(10,713)	(11,004)	(10,960)	(11,051)	(11,341)	(11,483)	(11,567)	(11,629)	(11,696)
J	G-J Generation (1)	12,752	12,847	13,693	13,188	13,188	12,790	12,790	12,790	12,790
K	G-J Generation Unavailability (2)	(1,103)	(1,216)	(1,978)	(1,925)	(1,925)	(1,884)	(1,884)	(1,884)	(1,884)
L	Temperature Based Generation Derates	0	0	0	0	0	0	0	0	0
M	Net ICAP External Imports (4)	1,390	1,390	1,390	1,390	1,390	1,390	1,390	1,390	1,390
N	**Total Resources Available (J+K+L+M)**	13,039	13,021	13,105	12,653	12,652	12,295	12,295	12,295	12,295
O	**Transmission Security Margin (I+N)**	2,326	2,017	2,146	1,602	1,312	813	728	666	599
P	Higher Demand Impact	(49)	(143)	(182)	(256)	(291)	(329)	(413)	(562)	(685)
Q	**Higher Demand Transmission Security Margin (O+P)**	2,277	1,874	1,964	1,346	1,021	484	315	104	(86)
R	Noncoincident Peak Demand Impact	(270)	(272)	(272)	(273)	(273)	(275)	(275)	(276)	(276)
S	**Noncoincident Peak Transmission Security Margin (O+R)**	2,056	1,745	1,874	1,329	1,039	538	453	390	323
T	2026 NYCA ICAP Market Peak Forecast Impact	(270)	-	-	-	-	-	-	-	-
U	**2026 NYCA ICAP Market Peak Forecast Margin (O+T)**	2,056	-	-	-	-	-	-	-	-

Notes:

1. Reflects the 2026 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).
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 40: 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	(10,801)	(10,968)	(11,078)	(11,199)	(11,356)	(11,503)	(11,668)	(11,813)	(11,986)
B	RECO Demand	(246)	(246)	(246)	(236)	(236)	(236)	(236)	(236)	(313)
C	**Total Demand (A+B)**	(11,047)	(11,214)	(11,324)	(11,435)	(11,592)	(11,739)	(11,904)	(12,049)	(12,299)
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	(977)	(977)	(977)	(977)	(977)	(977)	(977)	(977)	(977)
I	**Resource Need (C+G+H)**	(6,688)	(6,855)	(6,965)	(7,076)	(7,233)	(7,380)	(7,545)	(7,690)	(7,940)
J	G-J Generation (1)	13,673	13,649	13,649	12,997	12,586	12,586	12,586	12,586	12,586
K	G-J Generation Unavailability (2)	(998)	(998)	(998)	(998)	(998)	(998)	(998)	(998)	(998)
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)**	10,601	10,576	10,576	9,924	9,925	9,925	9,925	9,925	9,925
P	**Transmission Security Margin (I+O)**	3,913	3,721	3,611	2,848	2,692	2,545	2,380	2,235	1,985
Q	Higher Demand Impact	(174)	(257)	(385)	(461)	(618)	(854)	(1,097)	(1,494)	(1,737)
R	**Higher Demand Transmission Security Margin (P+Q)**	3,739	3,464	3,226	2,387	2,074	1,691	1,283	741	248
S	Noncoincident Peak Demand Impact	(34)	(35)	(36)	(37)	(37)	(37)	(38)	(40)	(41)
T	**Noncoincident Peak Transmission Security Margin (P+S)**	3,879	3,686	3,575	2,811	2,655	2,508	2,342	2,195	1,944

Notes:

1. Reflects the 2026 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).
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 41: 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	(10,801)	(10,968)	(11,078)	(11,199)	(11,356)	(11,503)	(11,668)	(11,813)	(11,986)
B	RECO Demand	(246)	(246)	(246)	(236)	(236)	(236)	(236)	(236)	(313)
C	**Total Demand (A+B)**	(11,047)	(11,214)	(11,324)	(11,435)	(11,592)	(11,739)	(11,904)	(12,049)	(12,299)
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	(977)	(977)	(977)	(977)	(977)	(977)	(977)	(977)	(977)
I	**Resource Need (C+G+H)**	(6,688)	(6,855)	(6,965)	(7,076)	(5,867)	(6,014)	(6,179)	(6,324)	(6,574)
J	G-J Generation (1)	13,788	14,610	14,610	13,958	13,547	13,547	13,547	13,547	13,547
K	G-J Generation Unavailability (2)	(1,113)	(1,796)	(1,796)	(1,796)	(1,796)	(1,796)	(1,796)	(1,796)	(1,796)
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)**	10,601	10,739	10,739	10,087	10,088	10,088	10,088	10,088	10,088
P	**Transmission Security Margin (I+O)**	3,913	3,885	3,775	3,011	4,221	4,074	3,909	3,764	3,514
Q	Higher Demand Impact	(174)	(257)	(385)	(461)	(618)	(854)	(1,097)	(1,494)	(1,737)
R	**Higher Demand Transmission Security Margin (P+Q)**	3,739	3,628	3,390	2,550	3,603	3,220	2,812	2,270	1,777
S	Noncoincident Peak Demand Impact	(34)	(35)	(36)	(37)	(37)	(37)	(38)	(40)	(41)
T	**Noncoincident Peak Transmission Security Margin (P+S)**	3,879	3,850	3,739	2,974	4,184	4,037	3,871	3,724	3,473

Notes:

1. Reflects the 2026 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).
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).[29] 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 status quo margin calculations where CHPE is not counted as an available resource, the limiting contingency combination is the loss of Ravenswood 3 followed by the loss of the Q12 cable. 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 90 MW in 2026 growing to 520 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).

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

Figure 42: 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**	(10,797)	(10,830)	(10,850)	(10,870)	(10,900)	(10,930)	(10,960)	(10,980)	(11,000)
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	(988)	(988)	(988)	(988)	(988)	(988)	(988)	(988)	(988)
F	**Resource Need (A+D+E)**	(7,896)	(7,929)	(7,949)	(7,969)	(7,999)	(8,029)	(8,059)	(8,079)	(8,099)
G	J Generation (1)	8,536	8,536	8,536	8,030	8,030	7,632	7,632	7,632	7,632
H	J Generation Unavailability (2)	(703)	(703)	(703)	(651)	(651)	(610)	(610)	(610)	(610)
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)**	7,972	7,972	7,972	7,518	7,518	7,161	7,161	7,161	7,161
L	**Baseline Transmission Security Margin (F+K)**	76	43	23	(451)	(481)	(868)	(898)	(918)	(938)
M	Higher Demand Impact	(43)	(130)	(160)	(220)	(240)	(270)	(340)	(460)	(560)
N	**Higher Demand Transmission Security Margin (L+M)**	33	(87)	(137)	(671)	(721)	(1,138)	(1,238)	(1,378)	(1,498)
O	Noncoincident Peak Demand Impact	(265)	(270)	(270)	(270)	(270)	(270)	(270)	(270)	(270)
P	**Noncoincident Peak Transmission Security Margin (L+O)**	(189)	(227)	(247)	(721)	(751)	(1,138)	(1,168)	(1,188)	(1,208)
Q	2026 NYCA ICAP Market Peak Forecast Impact	(265)	-	-	-	-	-	-	-	-
R	**2026 NYCA ICAP Market Peak Forecast Margin (L+Q)**	(189)	-	-	-	-	-	-	-	-

Notes:

1. Reflects the 2026 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).
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 43: 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**	(10,797)	(10,830)	(10,850)	(10,870)	(10,900)	(10,930)	(10,960)	(10,980)	(11,000)
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	(2,238)	(2,238)	(2,238)	(2,238)	(2,238)	(2,238)	(2,238)	(2,238)	(2,238)
F	**Resource Need (A+D+E)**	(8,346)	(8,379)	(8,399)	(8,419)	(8,349)	(8,379)	(8,409)	(8,429)	(8,449)
G	J Generation (1)	8,536	8,651	9,467	8,961	8,961	8,563	8,563	8,563	8,563
H	J Generation Unavailability (2)	(703)	(818)	(1,553)	(1,501)	(1,501)	(1,460)	(1,460)	(1,460)	(1,460)
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)**	9,222	9,222	9,304	8,850	8,850	8,493	8,493	8,493	8,493
L	**Baseline Transmission Security Margin (F+K)**	876	843	905	431	501	114	84	64	44
M	Higher Demand Impact	(43)	(130)	(160)	(220)	(240)	(270)	(340)	(460)	(560)
N	**Higher Demand Transmission Security Margin (L+M)**	833	713	745	211	261	(156)	(256)	(396)	(516)
O	Noncoincident Peak Demand Impact	(265)	(270)	(270)	(270)	(270)	(270)	(270)	(270)	(270)
P	**Noncoincident Peak Transmission Security Margin (L+O)**	611	573	635	161	231	(156)	(186)	(206)	(226)
Q	2026 NYCA ICAP Market Peak Forecast Impact	(265)	-	-	-	-	-	-	-	-
R	**2026 NYCA ICAP Market Peak Forecast Margin (L+Q)**	611	-	-	-	-	-	-	-	-

Notes:

1. Reflects the 2026 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 (2026 Gold Book Table I-9a) and solar PV peak reductions (2026 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).

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

Figure 44: 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**	(7,650)	(7,700)	(7,750)	(7,810)	(7,900)	(7,990)	(8,100)	(8,200)	(8,320)
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	(977)	(977)	(977)	(977)	(977)	(977)	(977)	(977)	(977)
F	**Resource Need (A+D+E)**	(4,738)	(4,788)	(4,838)	(4,898)	(4,988)	(5,078)	(5,188)	(5,288)	(5,408)
G	J Generation (1)	9,273	9,273	9,273	8,621	8,210	8,210	8,210	8,210	8,210
H	J Generation Unavailability (2)	(612)	(612)	(612)	(611)	(612)	(612)	(612)	(612)	(612)
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)**	6,744	6,744	6,744	6,092	6,092	6,092	6,092	6,092	6,092
M	**Transmission Security Margin (F+L)**	2,006	1,956	1,906	1,195	1,105	1,015	905	805	685
N	Higher Demand Impact	(160)	(230)	(310)	(390)	(490)	(650)	(810)	(1,080)	(1,220)
O	**Higher Demand Transmission Security Margin (M+N)**	1,846	1,726	1,596	805	615	365	95	(275)	(535)
P	Noncoincident Peak Demand Impact	(50)	(50)	(50)	(60)	(60)	(60)	(60)	(60)	(60)
Q	**Noncoincident Peak Transmission Security Margin (M+P)**	1,956	1,906	1,856	1,135	1,045	955	845	745	625

Notes:

1. Reflects the 2026 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).
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 45: 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**	(7,650)	(7,700)	(7,750)	(7,810)	(7,900)	(7,990)	(8,100)	(8,200)	(8,320)
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	(977)	(977)	(977)	(977)	(1,611)	(1,611)	(1,611)	(1,611)	(1,611)
F	**Resource Need (A+D+E)**	(4,738)	(4,788)	(4,838)	(4,898)	(4,622)	(4,712)	(4,822)	(4,922)	(5,042)
G	J Generation (1)	9,388	10,204	10,204	9,552	9,141	9,141	9,141	9,141	9,141
H	J Generation Unavailability (2)	(727)	(1,380)	(1,380)	(1,379)	(1,379)	(1,379)	(1,379)	(1,379)	(1,379)
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)**	6,744	6,907	6,907	6,256	6,256	6,256	6,256	6,256	6,256
M	**Transmission Security Margin (F+L)**	2,006	2,119	2,069	1,358	1,634	1,544	1,434	1,334	1,214
N	Higher Demand Impact	(160)	(230)	(310)	(390)	(490)	(650)	(810)	(1,080)	(1,220)
O	**Higher Demand Transmission Security Margin (M+N)**	1,846	1,889	1,759	968	1,144	894	624	254	(6)
P	Noncoincident Peak Demand Impact	(50)	(50)	(50)	(60)	(60)	(60)	(60)	(60)	(60)
Q	**Noncoincident Peak Transmission Security Margin (M+P)**	1,956	2,069	2,019	1,298	1,574	1,484	1,374	1,274	1,154

Notes:

1. Reflects the 2026 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).
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 46: 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**	(5,009)	(5,047)	(5,072)	(5,110)	(5,161)	(5,218)	(5,264)	(5,299)	(5,322)
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)**	(4,769)	(4,807)	(4,832)	(4,870)	(2,961)	(3,018)	(3,064)	(3,099)	(3,122)
G	K Generation (1)	4,897	4,897	5,821	5,821	5,821	5,776	5,776	5,776	5,776
H	K Generation Unavailability (2)	(625)	(625)	(1,457)	(1,457)	(1,457)	(1,452)	(1,453)	(1,453)	(1,453)
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)**	5,221	4,932	5,024	5,024	5,024	4,984	4,984	4,984	4,984
L	**Transmission Security Margin (F+K)**	452	125	192	154	2,063	1,966	1,920	1,885	1,862
M	Higher Demand Impact	(4)	(7)	(13)	(15)	(41)	(61)	(82)	(118)	(147)
N	**Higher Demand Transmission Security Margin (L+M)**	448	118	179	139	2,022	1,905	1,838	1,767	1,715
O	Noncoincident Peak Demand Impact	(88)	(89)	(89)	(90)	(91)	(92)	(93)	(93)	(94)
P	**Noncoincident Peak Transmission Security Margin (L+O)**	364	36	103	64	1,972	1,874	1,827	1,792	1,768
Q	2026 NYCA ICAP Market Peak Forecast Impact	(88)	-	-	-	-	-	-	-	-
R	**2026 NYCA ICAP Market Peak Forecast Margin (L+Q)**	364	-	-	-	-	-	-	-	-

Notes:

1. Reflects the 2026 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 (2026 Gold Book Table I-9a) and solar PV peak reductions (2026 Gold Book Table I-9c). Derates for run-of-river hydro are included. 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).
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 summer 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 47: 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**	(3,281)	(3,312)	(3,398)	(3,516)	(3,621)	(3,724)	(3,817)	(3,902)	(3,985)
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)	(374)	(374)	(374)	(374)	(374)
F	**Resource Need (A+D+E)**	(3,041)	(3,072)	(3,158)	(3,276)	(1,495)	(1,598)	(1,691)	(1,776)	(1,859)
G	K Generation (1)	5,341	6,265	6,265	6,265	6,219	6,219	6,219	6,219	6,219
H	K Generation Unavailability (2)	(631)	(1,370)	(1,370)	(1,370)	(1,371)	(1,371)	(1,371)	(1,371)	(1,371)
I	Shortage of Gas Fuel Supply (5)	(371)	(371)	(371)	(371)	(325)	(325)	(325)	(325)	(325)
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)**	5,288	5,184	5,184	5,184	5,183	5,183	5,183	5,183	5,183
M	**Transmission Security Margin (F+L)**	2,247	2,112	2,026	1,908	3,688	3,585	3,492	3,407	3,324
N	Higher Demand Impact	(20)	(15)	(29)	(88)	(155)	(246)	(348)	(529)	(601)
O	**Higher Demand Transmission Security Margin (M+N)**	2,227	2,097	1,997	1,820	3,533	3,339	3,144	2,878	2,723
P	Noncoincident Peak Demand Impact	(13)	(13)	(14)	(15)	(15)	(16)	(16)	(17)	(17)
Q	**Noncoincident Peak Transmission Security Margin (M+P)**	2,234	2,099	2,012	1,893	3,673	3,569	3,476	3,390	3,307

Notes:

1. Reflects the 2026 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).
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 for the as-planned system, considering the higher demand forecast with flexible large loads modeled offline.

- Figure 48: AOI - Statewide System Margin
- Figure 49: AOI - Lower Hudson Valley Transmission Security Margin
- Figure 50: AOI - New York City Transmission Security Margin
- Figure 51: AOI - Long Island Transmission Security Margin

Figure 48: AOI - Statewide System Margin

Statewide System Margin												
			Year	2026	2027	2028	2029	2030	2031	2032	2033	2034
Statewide System Margin Summer Peak - Baseline Expected Summer Weather, Normal Transfer Criteria (MW) (1)				1,946	1,185	1,088	(64)	(514)	(1,401)	(1,881)	(2,476)	(2,886)
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	62.6	(6.58)	56.02	1,890	1,129	1,032	(120)	(570)	(1,457)	(1,937)	(2,532)	(2,942)
Jamestown 5	11.8	(1.28)	10.52	1,935	1,174	1,077	(74)	(524)	(1,411)	(1,891)	(2,486)	(2,896)
Jamestown 6	10.3	(1.12)	9.18	1,936	1,176	1,079	(73)	(523)	(1,410)	(1,890)	(2,485)	(2,895)
Jamestown 7	40.5	(4.18)	36.32	1,909	1,148	1,051	(100)	(550)	(1,437)	(1,917)	(2,512)	(2,922)
Indeck-Yerkes	46.5	(2.19)	44.31	1,901	1,140	1,043	(108)	(558)	(1,445)	(1,925)	(2,520)	(2,930)
Indeck-Olean	79.2	(3.73)	75.47	1,870	1,109	1,012	(139)	(589)	(1,476)	(1,956)	(2,551)	(2,961)
American Ref-Fuel 1 & 2	27.6	(2.99)	24.61	1,921	1,160	1,063	(88)	(538)	(1,425)	(1,905)	(2,500)	(2,910)
American Ref-Fuel 1	13.8	(1.50)	12.30	1,933	1,172	1,075	(76)	(526)	(1,413)	(1,893)	(2,488)	(2,898)
American Ref-Fuel 2	13.8	(1.50)	12.30	1,933	1,172	1,075	(76)	(526)	(1,413)	(1,893)	(2,488)	(2,898)
Fortistar - N.Tonawanda (BTM:NG)	53.9	(2.54)	51.36	1,894	1,133	1,036	(115)	(565)	(1,452)	(1,932)	(2,527)	(2,937)
Model City Energy	5.6	(0.74)	4.86	1,941	1,180	1,083	(68)	(518)	(1,405)	(1,885)	(2,481)	(2,891)
Modern LF	6.4	(0.84)	5.56	1,940	1,179	1,082	(69)	(519)	(1,406)	(1,886)	(2,481)	(2,891)
Chaffee	6.4	(0.84)	5.56	1,940	1,179	1,082	(69)	(519)	(1,406)	(1,886)	(2,481)	(2,891)
Chautauqua LFGE	0.0	0.00	0.00	1,946	1,185	1,088	(64)	(514)	(1,401)	(1,881)	(2,476)	(2,886)
Lockport CC1, CC2, and CC3	206.1	(9.71)	196.39	1,749	988	891	(260)	(710)	(1,597)	(2,077)	(2,672)	(3,082)
Lockport CC1	68.7	(3.24)	65.46	1,880	1,119	1,022	(129)	(579)	(1,466)	(1,946)	(2,541)	(2,951)
Lockport CC2	68.7	(3.24)	65.46	1,880	1,119	1,022	(129)	(579)	(1,466)	(1,946)	(2,541)	(2,951)
Lockport CC3	68.7	(3.24)	65.46	1,880	1,119	1,022	(129)	(579)	(1,466)	(1,946)	(2,541)	(2,951)
Allegany	62.2	(2.93)	59.27	1,886	1,125	1,029	(123)	(573)	(1,460)	(1,940)	(2,535)	(2,945)
R. E. Ginna	578.8	(11.98)	566.82	1,379	618	521	(630)	(1,080)	(1,967)	(2,447)	(3,043)	(3,453)
Batavia	48.5	(2.28)	46.22	1,899	1,139	1,042	(110)	(560)	(1,447)	(1,927)	(2,522)	(2,932)
Nine Mile Point 2 (2)	1,276.9	(22.98)	1,253.92	956	195	98	(1,054)	(1,504)	(2,391)	(2,871)	(3,466)	(3,876)
Mill Seat	6.4	(0.84)	5.56	1,940	1,179	1,082	(69)	(519)	(1,406)	(1,886)	(2,481)	(2,891)
Hyland LFGE	4.8	(0.63)	4.17	1,941	1,181	1,084	(68)	(518)	(1,405)	(1,885)	(2,480)	(2,890)
Red Rochester (BTM:NG)	27.0	(2.93)	24.07	1,922	1,161	1,064	(88)	(538)	(1,425)	(1,905)	(2,500)	(2,910)
James A. FitzPatrick	840.7	(15.13)	825.57	1,120	359	262	(889)	(1,339)	(2,226)	(2,706)	(3,301)	(3,711)
Oswego 6	812.9	(88.20)	724.70	1,221	460	363	(788)	(1,238)	(2,125)	(2,605)	(3,200)	(3,610)
Oswego 5	800.6	(86.87)	713.73	1,232	471	374	(777)	(1,227)	(2,114)	(2,594)	(3,190)	(3,600)
Nine Mile Point 1	605.3	(10.90)	594.40	1,351	590	493	(658)	(1,108)	(1,995)	(2,475)	(3,070)	(3,480)
Independence GS1, GS2, GS3, & GS4	1,017.2	(47.91)	969.29	976	215	118	(1,033)	(1,483)	(2,370)	(2,850)	(3,445)	(3,855)
Independence GS1	254.3	(11.98)	242.32	1,703	942	845	(306)	(756)	(1,643)	(2,123)	(2,718)	(3,128)
Independence GS2	254.3	(11.98)	242.32	1,703	942	845	(306)	(756)	(1,643)	(2,123)	(2,718)	(3,128)

Statewide System Margin												
			Year	2026	2027	2028	2029	2030	2031	2032	2033	2034
Statewide System Margin Summer Peak - Baseline Expected Summer Weather, Normal Transfer Criteria (MW) (1)				1,946	1,185	1,088	(64)	(514)	(1,401)	(1,881)	(2,476)	(2,886)
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 GS3	254.3	(11.98)	242.32	1,703	942	845	(306)	(756)	(1,643)	(2,123)	(2,718)	(3,128)
Independence GS4	254.3	(11.98)	242.32	1,703	942	845	(306)	(756)	(1,643)	(2,123)	(2,718)	(3,128)
Syracuse	86.2	(4.06)	82.14	1,863	1,103	1,006	(146)	(596)	(1,483)	(1,963)	(2,558)	(2,968)
Carr St.-E. Syr	83.0	(3.91)	79.09	1,867	1,106	1,009	(143)	(593)	(1,480)	(1,960)	(2,555)	(2,965)
Indeck-Oswego	51.6	(2.43)	49.17	1,896	1,136	1,039	(113)	(563)	(1,450)	(1,930)	(2,525)	(2,935)
Indeck-Silver Springs	52.3	(2.46)	49.84	1,896	1,135	1,038	(113)	(563)	(1,450)	(1,930)	(2,526)	(2,936)
Greenidge 4 (BTM:NG)	57.2	(6.21)	50.99	1,895	1,134	1,037	(115)	(565)	(1,452)	(1,932)	(2,527)	(2,937)
Ontario LFGE	11.2	(1.48)	9.72	1,936	1,175	1,078	(73)	(523)	(1,410)	(1,890)	(2,485)	(2,895)
High Acres	9.6	(1.27)	8.33	1,937	1,176	1,079	(72)	(522)	(1,409)	(1,889)	(2,484)	(2,894)
Seneca Energy 1 & 2	17.6	(2.32)	15.28	1,930	1,169	1,072	(79)	(529)	(1,416)	(1,896)	(2,491)	(2,901)
Seneca Energy 1	8.8	(1.16)	7.64	1,938	1,177	1,080	(71)	(521)	(1,408)	(1,888)	(2,483)	(2,893)
Seneca Energy 2	8.8	(1.16)	7.64	1,938	1,177	1,080	(71)	(521)	(1,408)	(1,888)	(2,483)	(2,893)
Broome LFGE	2.4	(0.32)	2.08	1,944	1,183	1,086	(66)	(516)	(1,403)	(1,883)	(2,478)	(2,888)
Massena	80.9	(3.81)	77.09	1,869	1,108	1,011	(141)	(591)	(1,478)	(1,958)	(2,553)	(2,963)
Clinton LFGE	6.4	(0.84)	5.56	1,940	1,179	1,082	(69)	(519)	(1,406)	(1,886)	(2,481)	(2,891)
Saranac Energy CC1 & CC2	237.7	(11.20)	226.50	1,719	958	861	(290)	(740)	(1,627)	(2,107)	(2,702)	(3,112)
Saranac Energy CC1	123.4	(5.81)	117.59	1,828	1,067	970	(181)	(631)	(1,518)	(1,998)	(2,593)	(3,003)
Saranac Energy CC2	114.3	(5.38)	108.92	1,837	1,076	979	(172)	(622)	(1,509)	(1,989)	(2,585)	(2,995)
Sterling	48.4	(2.28)	46.12	1,900	1,139	1,042	(110)	(560)	(1,447)	(1,927)	(2,522)	(2,932)
Carthage Energy	52.8	(2.49)	50.31	1,895	1,134	1,037	(114)	(564)	(1,451)	(1,931)	(2,526)	(2,936)
Beaver Falls	79.8	(3.76)	76.04	1,870	1,109	1,012	(140)	(590)	(1,477)	(1,957)	(2,552)	(2,962)
Broome 2 LFGE	2.1	(0.28)	1.82	1,944	1,183	1,086	(65)	(515)	(1,402)	(1,882)	(2,478)	(2,888)
DANC LFGE	6.4	(0.84)	5.56	1,940	1,179	1,082	(69)	(519)	(1,406)	(1,886)	(2,481)	(2,891)
Oneida-Herkimer LFGE	3.2	(0.42)	2.78	1,943	1,182	1,085	(66)	(516)	(1,403)	(1,883)	(2,479)	(2,889)
Athens 1, 2, and 3	983.3	(46.31)	936.99	1,009	248	151	(1,001)	(1,451)	(2,338)	(2,818)	(3,413)	(3,823)
Athens 1	326.6	(15.38)	311.22	1,634	874	777	(375)	(825)	(1,712)	(2,192)	(2,787)	(3,197)
Athens 2	327.4	(15.42)	311.98	1,634	873	776	(376)	(826)	(1,713)	(2,193)	(2,788)	(3,198)
Athens 3	329.3	(15.51)	313.79	1,632	871	774	(377)	(827)	(1,714)	(2,194)	(2,790)	(3,200)
Rensselaer	77.0	(3.63)	73.37	1,872	1,111	1,014	(137)	(587)	(1,474)	(1,954)	(2,549)	(2,959)
Wheelabrator Hudson Falls	10.4	(1.13)	9.27	1,936	1,175	1,079	(73)	(523)	(1,410)	(1,890)	(2,485)	(2,895)
Selkirk I & II	348.3	(16.40)	331.90	1,614	853	756	(395)	(845)	(1,732)	(2,212)	(2,808)	(3,218)
Selkirk-I	75.2	(3.54)	71.66	1,874	1,113	1,016	(135)	(585)	(1,472)	(1,952)	(2,547)	(2,957)

Statewide System Margin												
			Year	2026	2027	2028	2029	2030	2031	2032	2033	2034
Statewide System Margin Summer Peak - Baseline Expected Summer Weather, Normal Transfer Criteria (MW) (1)				1,946	1,185	1,088	(64)	(514)	(1,401)	(1,881)	(2,476)	(2,886)
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)								
Selkirk-II	273.1	(12.86)	260.24	1,685	925	828	(324)	(774)	(1,661)	(2,141)	(2,736)	(3,146)
Indeck-Corinth	126.4	(5.95)	120.45	1,825	1,064	967	(184)	(634)	(1,521)	(2,001)	(2,596)	(3,006)
Castleton Energy Center	66.8	(3.15)	63.65	1,882	1,121	1,024	(127)	(577)	(1,464)	(1,944)	(2,539)	(2,949)
Bethlehem GS1, GS2, GS3	812.7	(38.28)	774.42	1,171	410	313	(838)	(1,288)	(2,175)	(2,655)	(3,250)	(3,660)
Bethlehem GS1	270.9	(12.76)	258.14	1,687	927	830	(322)	(772)	(1,659)	(2,139)	(2,734)	(3,144)
Bethlehem GS2	270.9	(12.76)	258.14	1,687	927	830	(322)	(772)	(1,659)	(2,139)	(2,734)	(3,144)
Bethlehem GS3	270.9	(12.76)	258.14	1,687	927	830	(322)	(772)	(1,659)	(2,139)	(2,734)	(3,144)
Albany LFGE	5.6	(0.74)	4.86	1,941	1,180	1,083	(68)	(518)	(1,405)	(1,885)	(2,481)	(2,891)
Fulton LFGE	3.2	(0.42)	2.78	1,943	1,182	1,085	(66)	(516)	(1,403)	(1,883)	(2,479)	(2,889)
Empire CC1 & CC2	584.8	(27.54)	557.26	1,388	628	531	(621)	(1,071)	(1,958)	(2,438)	(3,033)	(3,443)
Empire CC1	292.4	(13.77)	278.63	1,667	906	809	(342)	(792)	(1,679)	(2,159)	(2,754)	(3,164)
Empire CC2	292.4	(13.77)	278.63	1,667	906	809	(342)	(792)	(1,679)	(2,159)	(2,754)	(3,164)
Bowline 1 & 2	1,083.3	(117.54)	965.76	980	219	122	(1,029)	(1,479)	(2,366)	(2,846)	(3,442)	(3,852)
Bowline 1	541.7	(58.77)	482.93	1,463	702	605	(546)	(996)	(1,883)	(2,363)	(2,959)	(3,369)
Bowline 2	541.6	(58.76)	482.84	1,463	702	605	(546)	(996)	(1,883)	(2,363)	(2,959)	(3,369)
Danskammer 1, 2, 3, & 4 (3)	493.5	(53.54)	439.96	-	-	-	-	-	-	-	-	-
Danskammer 1 (3)	68.3	(7.41)	60.89	-	-	-	-	-	-	-	-	-
Danskammer 2 (3)	64.2	(6.97)	57.23	-	-	-	-	-	-	-	-	-
Danskammer 3 (3)	139.2	(15.10)	124.10	-	-	-	-	-	-	-	-	-
Danskammer 4 (3)	221.8	(24.07)	197.73	-	-	-	-	-	-	-	-	-
Roseton 1 & 2	1,208.8	(131.15)	1,077.65	868	107	10	(1,141)	(1,591)	(2,478)	(2,958)	(3,553)	(3,963)
Roseton 1	605.5	(65.70)	539.80	1,406	645	548	(603)	(1,053)	(1,940)	(2,420)	(3,016)	(3,426)
Roseton 2	603.3	(65.46)	537.84	1,408	647	550	(601)	(1,051)	(1,938)	(2,418)	(3,014)	(3,424)
Hillburn GT	36.3	(3.28)	33.02	1,913	1,152	1,055	(97)	(547)	(1,434)	(1,914)	(2,509)	(2,919)
Shoemaker GT	32.1	(2.90)	29.20	1,916	1,156	1,059	(93)	(543)	(1,430)	(1,910)	(2,505)	(2,915)
DCRRA	6.3	(0.68)	5.62	1,940	1,179	1,082	(69)	(519)	(1,406)	(1,886)	(2,481)	(2,891)
CPV Valley CC1 & CC2	654.2	(30.81)	623.39	1,322	561	464	(687)	(1,137)	(2,024)	(2,504)	(3,099)	(3,509)
CPV Valley CC1	323.3	(15.23)	308.07	1,638	877	780	(372)	(822)	(1,709)	(2,189)	(2,784)	(3,194)
CPV Valley CC2	330.9	(15.59)	315.31	1,630	869	772	(379)	(829)	(1,716)	(2,196)	(2,791)	(3,201)
Cricket Valley CC1, CC2, & CC3	1,046.2	(49.28)	996.92	949	188	91	(1,060)	(1,510)	(2,397)	(2,877)	(3,473)	(3,883)
Cricket Valley CC1	347.6	(16.37)	331.23	1,614	854	757	(395)	(845)	(1,732)	(2,212)	(2,807)	(3,217)
Cricket Valley CC2	347.4	(16.36)	331.04	1,615	854	757	(395)	(845)	(1,732)	(2,212)	(2,807)	(3,217)

Statewide System Margin												
			Year	2026	2027	2028	2029	2030	2031	2032	2033	2034
Statewide System Margin Summer Peak - Baseline Expected Summer Weather, Normal Transfer Criteria (MW) (1)				1,946	1,185	1,088	(64)	(514)	(1,401)	(1,881)	(2,476)	(2,886)
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 CC3	351.2	(16.54)	334.66	1,611	850	753	(398)	(848)	(1,735)	(2,215)	(2,810)	(3,220)
Wheelabrator Westchester	53.3	(5.78)	47.52	1,898	1,137	1,040	(111)	(561)	(1,448)	(1,928)	(2,523)	(2,933)
Arthur Kill ST 2 & 3	876.6	(95.11)	781.49	1,164	403	306	(845)	(1,295)	(2,182)	(2,662)	(3,257)	(3,667)
Arthur Kill ST 2	358.2	(38.86)	319.34	1,626	865	768	(383)	(833)	(1,720)	(2,200)	(2,795)	(3,205)
Arthur Kill ST 3	518.4	(56.25)	462.15	1,483	723	626	(526)	(976)	(1,863)	(2,343)	(2,938)	(3,348)
Brooklyn Navy Yard	250.8	(11.81)	238.99	1,707	946	849	(303)	(753)	(1,640)	(2,120)	(2,715)	(3,125)
Astoria 2, 3, & 5	899.5	(97.60)	801.90	1,144	383	286	(865)	(1,315)	(2,202)	(2,682)	(3,278)	(3,688)
Astoria 2	159.5	(17.31)	142.19	1,803	1,043	946	(206)	(656)	(1,543)	(2,023)	(2,618)	(3,028)
Astoria 3	369.9	(40.13)	329.77	1,616	855	758	(393)	(843)	(1,730)	(2,210)	(2,806)	(3,216)
Astoria 5	370.1	(40.16)	329.94	1,616	855	758	(393)	(843)	(1,730)	(2,210)	(2,806)	(3,216)
Ravenswood ST 01, 02, & 03	1,723.3	(186.98)	1,536.32	409	(352)	(449)	(1,600)	(2,050)	(2,937)	(3,417)	(4,012)	(4,422)
Ravenswood ST 01	360.3	(39.09)	321.21	1,624	864	767	(385)	(835)	(1,722)	(2,202)	(2,797)	(3,207)
Ravenswood ST 02	375.1	(40.70)	334.40	1,611	850	753	(398)	(848)	(1,735)	(2,215)	(2,810)	(3,220)
Ravenswood ST 03	987.9	(107.19)	880.71	1,065	304	207	(944)	(1,394)	(2,281)	(2,761)	(3,356)	(3,766)
Ravenswood CC 04	223.9	(10.55)	213.35	1,732	971	874	(277)	(727)	(1,614)	(2,094)	(2,689)	(3,099)
East River 1, 2, 6, & 7	615.5	(47.99)	567.51	1,378	617	520	(631)	(1,081)	(1,968)	(2,448)	(3,043)	(3,453)
East River 1	152.1	(7.16)	144.94	1,801	1,040	943	(208)	(658)	(1,545)	(2,025)	(2,621)	(3,031)
East River 2	153.9	(7.25)	146.65	1,799	1,038	941	(210)	(660)	(1,547)	(2,027)	(2,622)	(3,032)
East River 6	132.7	(14.40)	118.30	1,827	1,066	969	(182)	(632)	(1,519)	(1,999)	(2,594)	(3,004)
East River 7	176.8	(19.18)	157.62	1,788	1,027	930	(221)	(671)	(1,558)	(2,038)	(2,633)	(3,043)
Linden Cogen	715.0	(33.68)	681.32	1,264	503	406	(745)	(1,195)	(2,082)	(2,562)	(3,157)	(3,567)
KIAC_JFK (BTM:NG)	101.2	(4.77)	96.43	1,849	1,088	991	(160)	(610)	(1,497)	(1,977)	(2,572)	(2,982)
Gowanus 5 & 6 (4)	79.9	(8.25)	71.65	1,874	1,113	1,016	(135)	(585)	-	-	-	-
Gowanus 5 (4)	40.0	(4.13)	35.87	1,910	1,149	1,052	(99)	(549)	-	-	-	-
Gowanus 6 (4)	39.9	(4.12)	35.78	1,910	1,149	1,052	(99)	(549)	-	-	-	-
Kent (4)	40.0	(4.13)	35.87	1,910	1,149	1,052	(99)	(549)	-	-	-	-
Pouch (4)	39.2	(4.05)	35.15	1,910	1,150	1,053	(99)	(549)	-	-	-	-
Hellgate 1 & 2 (4)	79.5	(8.20)	71.30	1,874	1,113	1,016	(135)	(585)	-	-	-	-
Hellgate 1 (4)	39.9	(4.12)	35.78	1,910	1,149	1,052	(99)	(549)	-	-	-	-
Hellgate 2 (4)	39.6	(4.09)	35.51	1,910	1,149	1,052	(99)	(549)	-	-	-	-
Harlem River 1 & 2 (4)	79.5	(8.20)	71.30	1,874	1,113	1,016	(135)	(585)	-	-	-	-
Harlem River 1 (4)	39.9	(4.12)	35.78	1,910	1,149	1,052	(99)	(549)	-	-	-	-

Statewide System Margin												
			Year	2026	2027	2028	2029	2030	2031	2032	2033	2034
Statewide System Margin Summer Peak - Baseline Expected Summer Weather, Normal Transfer Criteria (MW) (1)				1,946	1,185	1,088	(64)	(514)	(1,401)	(1,881)	(2,476)	(2,886)
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 2 (4)	39.6	(4.09)	35.51	1,910	1,149	1,052	(99)	(549)	-	-	-	-
Vernon Blvd 2 & 3 (4)	79.9	(8.25)	71.65	1,874	1,113	1,016	(135)	(585)	-	-	-	-
Vernon Blvd 2 (4)	40.0	(4.13)	35.87	1,910	1,149	1,052	(99)	(549)	-	-	-	-
Vernon Blvd 3 (4)	39.9	(4.12)	35.78	1,910	1,149	1,052	(99)	(549)	-	-	-	-
Astoria CC 1 & 2	474.0	(22.33)	451.67	1,494	733	636	(515)	(965)	(1,852)	(2,332)	(2,927)	(3,337)
Astoria CC 1	237.0	(11.16)	225.84	1,720	959	862	(289)	(739)	(1,626)	(2,106)	(2,702)	(3,112)
Astoria CC 2	237.0	(11.16)	225.84	1,720	959	862	(289)	(739)	(1,626)	(2,106)	(2,702)	(3,112)
Astoria East Energy CC1 & CC2	589.2	(27.75)	561.45	1,384	623	526	(625)	(1,075)	(1,962)	(2,442)	(3,037)	(3,447)
Astoria East Energy - CC1	294.6	(13.88)	280.72	1,665	904	807	(344)	(794)	(1,681)	(2,161)	(2,756)	(3,166)
Astoria East Energy - CC2	294.6	(13.88)	280.72	1,665	904	807	(344)	(794)	(1,681)	(2,161)	(2,756)	(3,166)
Astoria Energy 2 - CC3 & CC4	570.0	(26.85)	543.15	1,402	642	545	(607)	(1,057)	(1,944)	(2,424)	(3,019)	(3,429)
Astoria Energy 2 - CC3	285.0	(13.42)	271.58	1,674	913	816	(335)	(785)	(1,672)	(2,152)	(2,747)	(3,157)
Astoria Energy 2 - CC4	285.0	(13.42)	271.58	1,674	913	816	(335)	(785)	(1,672)	(2,152)	(2,747)	(3,157)
Bayonne EC CT G1 through G10	592.7	(53.58)	539.12	1,407	646	549	(603)	(1,053)	(1,940)	(2,420)	(3,015)	(3,425)
Bayonne EC CTG1	59.5	(5.38)	54.12	1,892	1,131	1,034	(118)	(568)	(1,455)	(1,935)	(2,530)	(2,940)
Bayonne EC CTG2	54.6	(4.94)	49.66	1,896	1,135	1,038	(113)	(563)	(1,450)	(1,930)	(2,525)	(2,935)
Bayonne EC CTG3	58.8	(5.32)	53.48	1,892	1,131	1,034	(117)	(567)	(1,454)	(1,934)	(2,529)	(2,939)
Bayonne EC CTG4	61.1	(5.52)	55.58	1,890	1,129	1,032	(119)	(569)	(1,456)	(1,936)	(2,531)	(2,941)
Bayonne EC CTG5	59.9	(5.41)	54.49	1,891	1,130	1,033	(118)	(568)	(1,455)	(1,935)	(2,530)	(2,940)
Bayonne EC CTG6	60.5	(5.47)	55.03	1,891	1,130	1,033	(119)	(569)	(1,456)	(1,936)	(2,531)	(2,941)
Bayonne EC CTG7	57.0	(5.15)	51.85	1,894	1,133	1,036	(115)	(565)	(1,452)	(1,932)	(2,528)	(2,938)
Bayonne EC CTG8	60.5	(5.47)	55.03	1,891	1,130	1,033	(119)	(569)	(1,456)	(1,936)	(2,531)	(2,941)
Bayonne EC CTG9	60.4	(5.46)	54.94	1,891	1,130	1,033	(118)	(568)	(1,455)	(1,935)	(2,531)	(2,941)
Bayonne EC CTG10	60.4	(5.46)	54.94	1,891	1,130	1,033	(118)	(568)	(1,455)	(1,935)	(2,531)	(2,941)
Greenport IC 4, 5, & 6	5.6	(0.83)	4.77	1,941	1,180	1,083	(68)	(518)	(1,405)	(1,885)	(2,481)	(2,891)
Greenport IC 4	1.0	(0.15)	0.85	1,945	1,184	1,087	(64)	(514)	(1,401)	(1,881)	(2,477)	(2,887)
Greenport IC 5	1.5	(0.22)	1.28	1,944	1,183	1,086	(65)	(515)	(1,402)	(1,882)	(2,477)	(2,887)
Greenport IC 6	3.1	(0.46)	2.64	1,943	1,182	1,085	(66)	(516)	(1,403)	(1,883)	(2,478)	(2,888)
Freeport 1-2, 1-3, & 2-3	21.5	(2.47)	19.03	1,927	1,166	1,069	(83)	(533)	(1,420)	(1,900)	(2,495)	(2,905)
Freeport 1-2	2.5	(0.37)	2.13	1,944	1,183	1,086	(66)	(516)	(1,403)	(1,883)	(2,478)	(2,888)
Freeport 1-3	3.0	(0.45)	2.55	1,943	1,182	1,085	(66)	(516)	(1,403)	(1,883)	(2,478)	(2,888)
Freeport 2-3	16.0	(1.65)	14.35	1,931	1,170	1,073	(78)	(528)	(1,415)	(1,895)	(2,490)	(2,900)

Statewide System Margin												
			Year	2026	2027	2028	2029	2030	2031	2032	2033	2034
Statewide System Margin Summer Peak - Baseline Expected Summer Weather, Normal Transfer Criteria (MW) (1)				1,946	1,185	1,088	(64)	(514)	(1,401)	(1,881)	(2,476)	(2,886)
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)								
Charles P Killer 09 through 14	13.4	(1.77)	11.63	1,934	1,173	1,076	(75)	(525)	(1,412)	(1,892)	(2,487)	(2,897)
Charles P Keller 09	1.6	(0.21)	1.39	1,944	1,183	1,086	(65)	(515)	(1,402)	(1,882)	(2,477)	(2,887)
Charles P Keller 10	1.6	(0.21)	1.39	1,944	1,183	1,086	(65)	(515)	(1,402)	(1,882)	(2,477)	(2,887)
Charles P Keller 11	2.4	(0.32)	2.08	1,944	1,183	1,086	(66)	(516)	(1,403)	(1,883)	(2,478)	(2,888)
Charles P Keller 12	2.5	(0.33)	2.17	1,943	1,183	1,086	(66)	(516)	(1,403)	(1,883)	(2,478)	(2,888)
Charles P Keller 13	2.5	(0.33)	2.17	1,943	1,183	1,086	(66)	(516)	(1,403)	(1,883)	(2,478)	(2,888)
Charles P Keller 14	2.8	(0.37)	2.43	1,943	1,182	1,085	(66)	(516)	(1,403)	(1,883)	(2,478)	(2,888)
Wading River 1, 2, & 3	228.9	(23.62)	205.28	1,740	979	882	(269)	(719)	(1,606)	(2,086)	(2,681)	(3,091)
Wading River 1	77.4	(7.99)	69.41	1,876	1,115	1,018	(133)	(583)	(1,470)	(1,950)	(2,545)	(2,955)
Wading River 2	76.7	(7.92)	68.78	1,877	1,116	1,019	(132)	(582)	(1,469)	(1,949)	(2,545)	(2,955)
Wading River 3	74.8	(7.72)	67.08	1,879	1,118	1,021	(131)	(581)	(1,468)	(1,948)	(2,543)	(2,953)
Barrett ST 01 & 02	325.3	(35.30)	290.00	1,656	895	798	(354)	(804)	(1,691)	(2,171)	(2,766)	(3,176)
Barrett ST 01	144.3	(15.66)	128.64	1,817	1,056	959	(192)	(642)	(1,529)	(2,009)	(2,604)	(3,014)
Barrett ST 02	181.0	(19.64)	161.36	1,784	1,023	926	(225)	(675)	(1,562)	(2,042)	(2,637)	(3,047)
Barrett GT 01 through 12	259.4	(24.70)	234.70	1,711	950	853	(298)	(748)	(1,635)	(2,115)	(2,710)	(3,120)
Barrett GT 01	14.2	(1.47)	12.73	1,933	1,172	1,075	(76)	(526)	(1,413)	(1,893)	(2,489)	(2,899)
Barrett GT 02	14.3	(1.48)	12.82	1,933	1,172	1,075	(76)	(526)	(1,413)	(1,893)	(2,489)	(2,899)
Barrett 03	13.8	(1.42)	12.38	1,933	1,172	1,075	(76)	(526)	(1,413)	(1,893)	(2,488)	(2,898)
Barrett 04	15.1	(1.56)	13.54	1,932	1,171	1,074	(77)	(527)	(1,414)	(1,894)	(2,489)	(2,899)
Barrett 05	12.7	(1.31)	11.39	1,934	1,173	1,076	(75)	(525)	(1,412)	(1,892)	(2,487)	(2,897)
Barrett 06	14.0	(1.44)	12.56	1,933	1,172	1,075	(76)	(526)	(1,413)	(1,893)	(2,488)	(2,898)
Barrett 08	13.3	(1.37)	11.93	1,934	1,173	1,076	(75)	(525)	(1,412)	(1,892)	(2,488)	(2,898)
Barrett 09	40.4	(3.65)	36.75	1,909	1,148	1,051	(100)	(550)	(1,437)	(1,917)	(2,513)	(2,923)
Barrett 10	41.3	(3.73)	37.57	1,908	1,147	1,050	(101)	(551)	(1,438)	(1,918)	(2,513)	(2,923)
Barrett 11	40.0	(3.62)	36.38	1,909	1,148	1,051	(100)	(550)	(1,437)	(1,917)	(2,512)	(2,922)
Barrett 12	40.3	(3.64)	36.66	1,909	1,148	1,051	(100)	(550)	(1,437)	(1,917)	(2,512)	(2,922)
Northport 1, 2, 3, and 4	1,452.0	(157.54)	1,294.46	651	(110)	(207)	(1,358)	(1,808)	(2,695)	(3,175)	(3,770)	(4,180)
Northport 1	363.0	(39.39)	323.61	1,622	861	764	(387)	(837)	(1,724)	(2,204)	(2,799)	(3,209)
Northport 2	363.0	(39.39)	323.61	1,622	861	764	(387)	(837)	(1,724)	(2,204)	(2,799)	(3,209)
Northport 3	363.0	(39.39)	323.61	1,622	861	764	(387)	(837)	(1,724)	(2,204)	(2,799)	(3,209)
Northport 4	363.0	(39.39)	323.61	1,622	861	764	(387)	(837)	(1,724)	(2,204)	(2,799)	(3,209)
Port Jefferson GT 02 & 03	78.1	(8.06)	70.04	1,876	1,115	1,018	(134)	(584)	(1,471)	(1,951)	(2,546)	(2,956)

Statewide System Margin												
			Year	2026	2027	2028	2029	2030	2031	2032	2033	2034
Statewide System Margin Summer Peak - Baseline Expected Summer Weather, Normal Transfer Criteria (MW) (1)				1,946	1,185	1,088	(64)	(514)	(1,401)	(1,881)	(2,476)	(2,886)
Unit Name	Summer DMNC (MW)	NERC 5-Year Class Average De-Rate (MW)	Summer De-Rated Capability (MW)	Transmission Security Margin Considering Impact of Generator Outage (Retire, Mothball, IIFO)								
Port Jefferson GT 02	38.8	(4.00)	34.80	1,911	1,150	1,053	(98)	(548)	(1,435)	(1,915)	(2,511)	(2,921)
Port Jefferson GT 03	39.3	(4.06)	35.24	1,910	1,150	1,053	(99)	(549)	(1,436)	(1,916)	(2,511)	(2,921)
Port Jefferson 3 & 4	359.8	(39.04)	320.76	1,625	864	767	(384)	(834)	(1,721)	(2,201)	(2,797)	(3,207)
Port Jefferson 3	178.8	(19.40)	159.40	1,786	1,025	928	(223)	(673)	(1,560)	(2,040)	(2,635)	(3,045)
Port Jefferson 4	181.0	(19.64)	161.36	1,784	1,023	926	(225)	(675)	(1,562)	(2,042)	(2,637)	(3,047)
Hempstead (RR)	74.5	(8.08)	66.42	1,879	1,118	1,021	(130)	(580)	(1,467)	(1,947)	(2,542)	(2,952)
Glenwood GT 02, 04, & 05	126.9	(13.10)	113.80	1,832	1,071	974	(177)	(627)	(1,514)	(1,994)	(2,590)	(3,000)
Glenwood GT 02	48.3	(4.98)	43.32	1,902	1,141	1,044	(107)	(557)	(1,444)	(1,924)	(2,519)	(2,929)
Glenwood GT 04	38.4	(3.96)	34.44	1,911	1,150	1,053	(98)	(548)	(1,435)	(1,915)	(2,510)	(2,920)
Glenwood GT 05	40.2	(4.15)	36.05	1,910	1,149	1,052	(100)	(550)	(1,437)	(1,917)	(2,512)	(2,922)
Holtsville 01 through 10	510.1	(46.11)	463.99	1,482	721	624	(528)	(978)	(1,865)	(2,345)	(2,940)	(3,350)
Holtsville 01	53.0	(4.79)	48.21	1,897	1,137	1,040	(112)	(562)	(1,449)	(1,929)	(2,524)	(2,934)
Holtsville 02	52.0	(4.70)	47.30	1,898	1,137	1,040	(111)	(561)	(1,448)	(1,928)	(2,523)	(2,933)
Holtsville 03	46.9	(4.24)	42.66	1,903	1,142	1,045	(106)	(556)	(1,443)	(1,923)	(2,518)	(2,928)
Holtsville 04	50.9	(4.60)	46.30	1,899	1,138	1,041	(110)	(560)	(1,447)	(1,927)	(2,522)	(2,932)
Holtsville 05	49.4	(4.47)	44.93	1,901	1,140	1,043	(108)	(558)	(1,445)	(1,925)	(2,521)	(2,931)
Holtsville 06	52.7	(4.76)	47.94	1,898	1,137	1,040	(111)	(561)	(1,448)	(1,928)	(2,524)	(2,934)
Holtsville 07	50.0	(4.52)	45.48	1,900	1,139	1,042	(109)	(559)	(1,446)	(1,926)	(2,521)	(2,931)
Holtsville 08	49.6	(4.48)	45.12	1,901	1,140	1,043	(109)	(559)	(1,446)	(1,926)	(2,521)	(2,931)
Holtsville 09	52.3	(4.73)	47.57	1,898	1,137	1,040	(111)	(561)	(1,448)	(1,928)	(2,523)	(2,933)
Holtsville 10	53.3	(4.82)	48.48	1,897	1,136	1,039	(112)	(562)	(1,449)	(1,929)	(2,524)	(2,934)
Shoreham GT 3 & 4	82.7	(8.53)	74.17	1,871	1,111	1,014	(138)	(588)	(1,475)	(1,955)	(2,550)	(2,960)
Shoreham GT3	41.4	(4.27)	37.13	1,909	1,148	1,051	(101)	(551)	(1,438)	(1,918)	(2,513)	(2,923)
Shoreham GT4	41.3	(4.26)	37.04	1,909	1,148	1,051	(101)	(551)	(1,438)	(1,918)	(2,513)	(2,923)
East Hampton GT 01, 2, 3, & 4	23.5	(2.44)	21.06	1,925	1,164	1,067	(85)	(535)	(1,422)	(1,902)	(2,497)	(2,907)
East Hampton GT 01	18.1	(1.64)	16.46	1,929	1,168	1,071	(80)	(530)	(1,417)	(1,897)	(2,492)	(2,902)
East Hampton 2	1.8	(0.27)	1.53	1,944	1,183	1,086	(65)	(515)	(1,402)	(1,882)	(2,477)	(2,887)
East Hampton 3	1.8	(0.27)	1.53	1,944	1,183	1,086	(65)	(515)	(1,402)	(1,882)	(2,477)	(2,887)
East Hampton 4	1.8	(0.27)	1.53	1,944	1,183	1,086	(65)	(515)	(1,402)	(1,882)	(2,477)	(2,887)
Southold 1	9.8	(1.01)	8.79	1,937	1,176	1,079	(72)	(522)	(1,409)	(1,889)	(2,485)	(2,895)
S Hampton 1	8.1	(0.84)	7.26	1,938	1,178	1,081	(71)	(521)	(1,408)	(1,888)	(2,483)	(2,893)
Freeport CT 1 & 2	88.7	(9.15)	79.55	1,866	1,105	1,008	(143)	(593)	(1,480)	(1,960)	(2,555)	(2,965)

Statewide System Margin												
			Year	2026	2027	2028	2029	2030	2031	2032	2033	2034
Statewide System Margin Summer Peak - Baseline Expected Summer Weather, Normal Transfer Criteria (MW) (1)				1,946	1,185	1,088	(64)	(514)	(1,401)	(1,881)	(2,476)	(2,886)
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 CT 1	45.7	(4.72)	40.98	1,905	1,144	1,047	(105)	(555)	(1,442)	(1,922)	(2,517)	(2,927)
Freeport CT 2	43.0	(4.44)	38.56	1,907	1,146	1,049	(102)	(552)	(1,439)	(1,919)	(2,514)	(2,924)
Flynn	139.5	(6.57)	132.93	1,813	1,052	955	(196)	(646)	(1,533)	(2,013)	(2,609)	(3,019)
Greenport GT1	54.5	(4.93)	49.57	1,896	1,135	1,038	(113)	(563)	(1,450)	(1,930)	(2,525)	(2,935)
Far Rockaway GT1 & GT2	68.4	(6.18)	62.22	1,883	1,123	1,026	(126)	(576)	(1,463)	(1,943)	(2,538)	(2,948)
Far Rockaway GT1	22.4	(2.02)	20.38	1,925	1,164	1,067	(84)	(534)	(1,421)	(1,901)	(2,496)	(2,906)
Far Rockaway GT2	46.0	(4.16)	41.84	1,904	1,143	1,046	(105)	(555)	(1,442)	(1,922)	(2,518)	(2,928)
Bethpage	46.0	(2.17)	43.83	1,902	1,141	1,044	(107)	(557)	(1,444)	(1,924)	(2,520)	(2,930)
Bethpage 3	75.0	(3.53)	71.47	1,874	1,113	1,016	(135)	(585)	(1,472)	(1,952)	(2,547)	(2,957)
Bethpage GT4	43.8	(4.52)	39.28	1,906	1,145	1,048	(103)	(553)	(1,440)	(1,920)	(2,515)	(2,925)
Stony Brook (BTM:NG)	0.0	0.00	0.00	1,946	1,185	1,088	(64)	(514)	(1,401)	(1,881)	(2,476)	(2,886)
Brentwood (4)	45.0	(4.64)	40.36	1,905	1,144	1,047	(104)	(554)	-	-	-	-
Pilgrim GT1 & GT2	84.9	(8.76)	76.14	1,869	1,109	1,012	(140)	(590)	(1,477)	(1,957)	(2,552)	(2,962)
Pilgrim GT1	42.0	(4.33)	37.67	1,908	1,147	1,050	(101)	(551)	(1,438)	(1,918)	(2,513)	(2,923)
Pilgrim GT2	42.9	(4.43)	38.47	1,907	1,146	1,049	(102)	(552)	(1,439)	(1,919)	(2,514)	(2,924)
Pinelawn Power 1	72.6	(3.42)	69.18	1,876	1,116	1,019	(133)	(583)	(1,470)	(1,950)	(2,545)	(2,955)
Caithness_CC_1	321.8	(15.16)	306.64	1,639	878	781	(370)	(820)	(1,707)	(2,187)	(2,782)	(3,192)
Islip (RR)	7.5	(0.81)	6.69	1,939	1,178	1,081	(70)	(520)	(1,407)	(1,887)	(2,482)	(2,892)
Babylon (RR)	15.8	(1.71)	14.09	1,932	1,171	1,074	(78)	(528)	(1,415)	(1,895)	(2,490)	(2,900)
Huntington (RR)	24.8	(2.69)	22.11	1,924	1,163	1,066	(86)	(536)	(1,423)	(1,903)	(2,498)	(2,908)

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 49: AOI - Lower Hudson Valley Transmission Security Margin

Lower Hudson Valley												
Year				2026	2027	2028	2029	2030	2031	2032	2033	2034
Lower Hudson Valley Transmission Security Margin, Summer Peak - Baseline Expected Summer Weather, Normal Transfer Criteria (MW) (1)				2,056	1,745	1,874	1,329	1,021	484	315	104	(86)
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	1,083.3	(117.54)	965.76	1,090	780	908	363	55	(482)	(651)	(862)	(1,052)
Bowline 1	541.7	(58.77)	482.93	1,573	1,262	1,391	846	538	1	(168)	(379)	(569)
Bowline 2	541.6	(58.76)	482.84	1,573	1,262	1,391	846	538	1	(168)	(379)	(569)
Danskammer 1, 2, 3, & 4 (2)	493.5	(53.54)	439.96	-	-	-	-	-	-	-	-	-
Danskammer 1 (2)	68.3	(7.41)	60.89	-	-	-	-	-	-	-	-	-
Danskammer 2 (2)	64.2	(6.97)	57.23	-	-	-	-	-	-	-	-	-
Danskammer 3 (2)	139.2	(15.10)	124.10	-	-	-	-	-	-	-	-	-
Danskammer 4 (2)	221.8	(24.07)	197.73	-	-	-	-	-	-	-	-	-
Roseton 1 & 2	1,208.8	(131.15)	1,077.65	978	668	796	251	(57)	(594)	(763)	(974)	(1,164)
Roseton 1	605.5	(65.70)	539.80	1,516	1,206	1,334	789	481	(56)	(225)	(436)	(626)
Roseton 2	603.3	(65.46)	537.84	1,518	1,207	1,336	791	483	(54)	(223)	(434)	(624)
Hillburn GT	36.3	(3.28)	33.02	2,023	1,712	1,841	1,296	988	451	282	71	(119)
Shoemaker GT	32.1	(2.90)	29.20	2,027	1,716	1,845	1,300	991	454	286	75	(115)
DCRRA	6.3	(0.68)	5.62	2,050	1,740	1,868	1,323	1,015	478	309	98	(92)
CPV Valley CC1 & CC2	654.2	(30.81)	623.39	1,432	1,122	1,250	706	397	(140)	(308)	(519)	(709)
CPV Valley CC1	323.3	(15.23)	308.07	1,748	1,437	1,566	1,021	713	176	7	(204)	(394)
CPV Valley CC2	330.9	(15.59)	315.31	1,740	1,430	1,558	1,014	705	168	(0)	(211)	(401)
Cricket Valley CC1, CC2, & CC3	1,046.2	(49.28)	996.92	1,059	748	877	332	24	(513)	(682)	(893)	(1,083)
Cricket Valley CC1	347.6	(16.37)	331.23	1,724	1,414	1,542	998	689	152	(16)	(227)	(417)
Cricket Valley CC2	347.4	(16.36)	331.04	1,725	1,414	1,543	998	690	153	(16)	(227)	(417)
Cricket Valley CC3	351.2	(16.54)	334.66	1,721	1,411	1,539	994	686	149	(20)	(231)	(421)
Wheelabrator Westchester	53.3	(5.78)	47.52	2,008	1,698	1,826	1,281	973	436	268	57	(133)
Arthur Kill ST 2 & 3	876.6	(95.11)	781.49	1,274	964	1,092	547	239	(298)	(466)	(677)	(867)
Arthur Kill ST 2	358.2	(38.86)	319.34	1,736	1,426	1,554	1,010	701	164	(4)	(215)	(405)
Arthur Kill ST 3	518.4	(56.25)	462.15	1,594	1,283	1,412	867	558	21	(147)	(358)	(548)
Brooklyn Navy Yard	250.8	(11.81)	238.99	1,817	1,506	1,635	1,090	782	245	76	(135)	(325)
Astoria 2, 3, & 5	899.5	(97.60)	801.90	1,254	943	1,072	527	219	(318)	(487)	(698)	(888)
Astoria 2	159.5	(17.31)	142.19	1,914	1,603	1,732	1,187	878	341	173	(38)	(228)
Astoria 3	369.9	(40.13)	329.77	1,726	1,416	1,544	999	691	154	(15)	(226)	(416)
Astoria 5	370.1	(40.16)	329.94	1,726	1,415	1,544	999	691	154	(15)	(226)	(416)
Ravenswood ST 01, 02, & 03	1,723.3	(186.98)	1,536.32	519	209	337	(207)	(516)	(1,053)	(1,221)	(1,432)	(1,622)
Ravenswood ST 01	360.3	(39.09)	321.21	1,735	1,424	1,553	1,008	699	162	(6)	(217)	(407)

Lower Hudson Valley												
Year				2026	2027	2028	2029	2030	2031	2032	2033	2034
Lower Hudson Valley Transmission Security Margin, Summer Peak - Baseline Expected Summer Weather, Normal Transfer Criteria (MW) (1)				2,056	1,745	1,874	1,329	1,021	484	315	104	(86)
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 02	375.1	(40.70)	334.40	1,721	1,411	1,539	995	686	149	(19)	(230)	(420)
Ravenswood ST 03	987.9	(107.19)	880.71	1,175	865	993	448	140	(397)	(566)	(777)	(967)
Ravenswood CC 04	223.9	(10.55)	213.35	1,842	1,532	1,660	1,116	807	270	102	(109)	(299)
East River 1, 2, 6, & 7	615.5	(47.99)	567.51	1,488	1,178	1,306	761	453	(84)	(252)	(463)	(653)
East River 1	152.1	(7.16)	144.94	1,911	1,600	1,729	1,184	876	339	170	(41)	(231)
East River 2	153.9	(7.25)	146.65	1,909	1,599	1,727	1,182	874	337	168	(43)	(233)
East River 6	132.7	(14.40)	118.30	1,937	1,627	1,755	1,211	902	365	197	(14)	(204)
East River 7	176.8	(19.18)	157.62	1,898	1,588	1,716	1,171	863	326	157	(54)	(244)
Linden Cogen	715.0	(33.68)	681.32	1,374	1,064	1,192	648	339	(198)	(366)	(577)	(767)
KIAC_JFK (BTM:NG)	101.2	(4.77)	96.43	1,959	1,649	1,777	1,232	924	387	219	8	(182)
Gowanus 5 & 6 (3)	79.9	(8.25)	71.65	1,984	1,674	1,802	1,257	949	-	-	-	-
Gowanus 5 (3)	40.0	(4.13)	35.87	2,020	1,709	1,838	1,293	985	-	-	-	-
Gowanus 6 (3)	39.9	(4.12)	35.78	2,020	1,710	1,838	1,293	985	-	-	-	-
Kent (3)	40.0	(4.13)	35.87	2,020	1,709	1,838	1,293	985	-	-	-	-
Pouch (3)	39.2	(4.05)	35.15	2,021	1,710	1,839	1,294	985	-	-	-	-
Hellgate 1 & 2 (3)	79.5	(8.20)	71.30	1,984	1,674	1,802	1,258	949	-	-	-	-
Hellgate 1 (3)	39.9	(4.12)	35.78	2,020	1,710	1,838	1,293	985	-	-	-	-
Hellgate 2 (3)	39.6	(4.09)	35.51	2,020	1,710	1,838	1,293	985	-	-	-	-
Harlem River 1 & 2 (3)	79.5	(8.20)	71.30	1,984	1,674	1,802	1,258	949	-	-	-	-
Harlem River 1 (3)	39.9	(4.12)	35.78	2,020	1,710	1,838	1,293	985	-	-	-	-
Harlem River 2 (3)	39.6	(4.09)	35.51	2,020	1,710	1,838	1,293	985	-	-	-	-
Vernon Blvd 2 & 3 (3)	79.9	(8.25)	71.65	1,984	1,674	1,802	1,257	949	-	-	-	-
Vernon Blvd 2 (3)	40.0	(4.13)	35.87	2,020	1,709	1,838	1,293	985	-	-	-	-
Vernon Blvd 3 (3)	39.9	(4.12)	35.78	2,020	1,710	1,838	1,293	985	-	-	-	-
Astoria CC 1 & 2	474.0	(22.33)	451.67	1,604	1,294	1,422	877	569	32	(137)	(348)	(538)
Astoria CC 1	237.0	(11.16)	225.84	1,830	1,519	1,648	1,103	795	258	89	(122)	(312)
Astoria CC 2	237.0	(11.16)	225.84	1,830	1,519	1,648	1,103	795	258	89	(122)	(312)
Astoria East Energy CC1 & CC2	589.2	(27.75)	561.45	1,494	1,184	1,312	767	459	(78)	(246)	(457)	(647)
Astoria East Energy - CC1	294.6	(13.88)	280.72	1,775	1,465	1,593	1,048	740	203	34	(177)	(367)
Astoria East Energy - CC2	294.6	(13.88)	280.72	1,775	1,465	1,593	1,048	740	203	34	(177)	(367)
Astoria Energy 2 - CC3 & CC4	570.0	(26.85)	543.15	1,513	1,202	1,331	786	477	(60)	(228)	(439)	(629)
Astoria Energy 2 - CC3	285.0	(13.42)	271.58	1,784	1,474	1,602	1,057	749	212	44	(167)	(357)

Lower Hudson Valley												
Year				2026	2027	2028	2029	2030	2031	2032	2033	2034
Lower Hudson Valley Transmission Security Margin, Summer Peak - Baseline Expected Summer Weather, Normal Transfer Criteria (MW) (1)				2,056	1,745	1,874	1,329	1,021	484	315	104	(86)
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 - CC4	285.0	(13.42)	271.58	1,784	1,474	1,602	1,057	749	212	44	(167)	(357)
Bayonne EC CT G1 through G10	592.7	(53.58)	539.12	1,517	1,206	1,335	790	482	(55)	(224)	(435)	(625)
Bayonne EC CTG1	59.5	(5.38)	54.12	2,002	1,691	1,820	1,275	967	430	261	50	(140)
Bayonne EC CTG2	54.6	(4.94)	49.66	2,006	1,696	1,824	1,279	971	434	265	54	(136)
Bayonne EC CTG3	58.8	(5.32)	53.48	2,002	1,692	1,820	1,275	967	430	262	51	(139)
Bayonne EC CTG4	61.1	(5.52)	55.58	2,000	1,690	1,818	1,273	965	428	260	49	(141)
Bayonne EC CTG5	59.9	(5.41)	54.49	2,001	1,691	1,819	1,274	966	429	261	50	(140)
Bayonne EC CTG6	60.5	(5.47)	55.03	2,001	1,690	1,819	1,274	966	429	260	49	(141)
Bayonne EC CTG7	57.0	(5.15)	51.85	2,004	1,693	1,822	1,277	969	432	263	52	(138)
Bayonne EC CTG8	60.5	(5.47)	55.03	2,001	1,690	1,819	1,274	966	429	260	49	(141)
Bayonne EC CTG9	60.4	(5.46)	54.94	2,001	1,690	1,819	1,274	966	429	260	49	(141)
Bayonne EC CTG10	60.4	(5.46)	54.94	2,001	1,690	1,819	1,274	966	429	260	49	(141)

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

Figure 50: AOI - New York City Transmission Security Margin

New York City												
			Year	2026	2027	2028	2029	2030	2031	2032	2033	2034
New York City Transmission Security Margin, Summer Peak - Baseline Expected Summer Weather, Normal Transfer Criteria (MW) (1)				611	573	635	161	231	(156)	(256)	(396)	(516)
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	876.6	(95.11)	781.49	(170)	(208)	(147)	(620)	(550)	(937)	(1,037)	(1,177)	(1,297)
Arthur Kill ST 2	358.2	(38.86)	319.34	292	254	315	(158)	(88)	(475)	(575)	(715)	(835)
Arthur Kill ST 3	518.4	(56.25)	462.15	149	111	173	(301)	(231)	(618)	(718)	(858)	(978)
Brooklyn Navy Yard	250.8	(11.81)	238.99	372	334	396	(78)	(8)	(395)	(495)	(635)	(755)
Astoria 2, 3, & 5	899.5	(97.60)	801.90	(191)	(229)	(167)	(641)	(571)	(958)	(1,058)	(1,198)	(1,318)
Astoria 2	159.5	(17.31)	142.19	469	431	493	19	89	(298)	(398)	(538)	(658)
Astoria 3	369.9	(40.13)	329.77	281	243	305	(169)	(99)	(486)	(586)	(726)	(846)
Astoria 5	370.1	(40.16)	329.94	281	243	305	(169)	(99)	(486)	(586)	(726)	(846)
Ravenswood ST 01, 02, & 03 (2)	1,723.3	(186.98)	1,536.32	(737)	(775)	(714)	(1,187)	(1,117)	(1,504)	(1,604)	(1,744)	(1,864)
Ravenswood ST 01	360.3	(39.09)	321.21	290	252	314	(160)	(90)	(477)	(577)	(717)	(837)
Ravenswood ST 02	375.1	(40.70)	334.40	277	239	300	(173)	(103)	(490)	(590)	(730)	(850)
Ravenswood ST 03 (2)	987.9	(107.19)	880.71	(82)	(120)	(58)	(532)	(462)	(849)	(949)	(1,089)	(1,209)
Ravenswood CC 04	223.9	(10.55)	213.35	398	360	421	(52)	18	(369)	(469)	(609)	(729)
East River 1, 2, 6, & 7	615.5	(47.99)	567.51	44	6	67	(407)	(337)	(724)	(824)	(964)	(1,084)
East River 1	152.1	(7.16)	144.94	466	428	490	16	86	(301)	(401)	(541)	(661)
East River 2	153.9	(7.25)	146.65	465	427	488	14	84	(303)	(403)	(543)	(663)
East River 6	132.7	(14.40)	118.30	493	455	516	43	113	(274)	(374)	(514)	(634)
East River 7	176.8	(19.18)	157.62	454	416	477	3	73	(314)	(414)	(554)	(674)
Linden Cogen	715.0	(33.68)	681.32	(70)	(108)	(47)	(520)	(450)	(837)	(937)	(1,077)	(1,197)
KIAC_JFK (BTM:NG)	101.2	(4.77)	96.43	515	477	538	65	135	(252)	(352)	(492)	(612)
Gowanus 5 & 6 (3)	79.9	(8.25)	71.65	540	502	563	89	159	-	-	-	-
Gowanus 5 (3)	40.0	(4.13)	35.87	575	537	599	125	195	-	-	-	-
Gowanus 6 (3)	39.9	(4.12)	35.78	575	537	599	125	195	-	-	-	-
Kent (3)	40.0	(4.13)	35.87	575	537	599	125	195	-	-	-	-
Pouch (3)	39.2	(4.05)	35.15	576	538	600	126	196	-	-	-	-
Hellgate 1 & 2 (3)	79.5	(8.20)	71.30	540	502	564	90	160	-	-	-	-
Hellgate 1 (3)	39.9	(4.12)	35.78	575	537	599	125	195	-	-	-	-
Hellgate 2 (3)	39.6	(4.09)	35.51	576	538	599	125	195	-	-	-	-
Harlem River 1 & 2 (3)	79.5	(8.20)	71.30	540	502	564	90	160	-	-	-	-
Harlem River 1 (3)	39.9	(4.12)	35.78	575	537	599	125	195	-	-	-	-
Harlem River 2 (3)	39.6	(4.09)	35.51	576	538	599	125	195	-	-	-	-
Vernon Blvd 2 & 3 (3)	79.9	(8.25)	71.65	540	502	563	89	159	-	-	-	-
Vernon Blvd 2 (3)	40.0	(4.13)	35.87	575	537	599	125	195	-	-	-	-

New York City												
			Year	2026	2027	2028	2029	2030	2031	2032	2033	2034
New York City Transmission Security Margin, Summer Peak - Baseline Expected Summer Weather, Normal Transfer Criteria (MW) (1)				611	573	635	161	231	(156)	(256)	(396)	(516)
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	575	537	599	125	195	-	-	-	-
Astoria CC 1 & 2	474.0	(22.33)	451.67	160	122	183	(291)	(221)	(608)	(708)	(848)	(968)
Astoria CC 1	237.0	(11.16)	225.84	385	347	409	(65)	5	(382)	(482)	(622)	(742)
Astoria CC 2	237.0	(11.16)	225.84	385	347	409	(65)	5	(382)	(482)	(622)	(742)
Astoria East Energy CC1 & CC2	589.2	(27.75)	561.45	50	12	73	(400)	(330)	(717)	(817)	(957)	(1,077)
Astoria East Energy - CC1	294.6	(13.88)	280.72	330	292	354	(120)	(50)	(437)	(537)	(677)	(797)
Astoria East Energy - CC2	294.6	(13.88)	280.72	330	292	354	(120)	(50)	(437)	(537)	(677)	(797)
Astoria Energy 2 - CC3 & CC4	570.0	(26.85)	543.15	68	30	92	(382)	(312)	(699)	(799)	(939)	(1,059)
Astoria Energy 2 - CC3	285.0	(13.42)	271.58	340	302	363	(111)	(41)	(428)	(528)	(668)	(788)
Astoria Energy 2 - CC4	285.0	(13.42)	271.58	340	302	363	(111)	(41)	(428)	(528)	(668)	(788)
Bayonne EC CT G1 through G10	592.7	(53.58)	539.12	72	34	96	(378)	(308)	(695)	(795)	(935)	(1,055)
Bayonne EC CTG1	59.5	(5.38)	54.12	557	519	581	107	177	(210)	(310)	(450)	(570)
Bayonne EC CTG2	54.6	(4.94)	49.66	562	524	585	111	181	(206)	(306)	(446)	(566)
Bayonne EC CTG3	58.8	(5.32)	53.48	558	520	581	108	178	(209)	(309)	(449)	(569)
Bayonne EC CTG4	61.1	(5.52)	55.58	556	518	579	105	175	(212)	(312)	(452)	(572)
Bayonne EC CTG5	59.9	(5.41)	54.49	557	519	580	107	177	(210)	(310)	(450)	(570)
Bayonne EC CTG6	60.5	(5.47)	55.03	556	518	580	106	176	(211)	(311)	(451)	(571)
Bayonne EC CTG7	57.0	(5.15)	51.85	559	521	583	109	179	(208)	(308)	(448)	(568)
Bayonne EC CTG8	60.5	(5.47)	55.03	556	518	580	106	176	(211)	(311)	(451)	(571)
Bayonne EC CTG9	60.4	(5.46)	54.94	556	518	580	106	176	(211)	(311)	(451)	(571)
Bayonne EC CTG10	60.4	(5.46)	54.94	556	518	580	106	176	(211)	(311)	(451)	(571)

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 CHPE and one transmission element is utilized.
3. Unit is modeled out of service beginning in 2031 in the baseline margin calculation.

Figure 51: AOI - Long Island Transmission Security Margin

Long Island												
			Year	2026	2027	2028	2029	2030	2031	2032	2033	2034
Long Island Transmission Security Margin, Summer Peak - Baseline Expected Summer Weather, Normal Transfer Criteria (MW) (1)				364	36	103	64	1,972	1,874	1,827	1,767	1,715
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	359	31	99	60	1,968	1,870	1,822	1,762	1,710
Greenport IC 4	1.0	(0.15)	0.85	363	35	103	64	1,972	1,874	1,826	1,766	1,714
Greenport IC 5	1.5	(0.22)	1.28	363	35	102	63	1,971	1,873	1,826	1,766	1,714
Greenport IC 6	3.1	(0.46)	2.64	361	33	101	62	1,970	1,872	1,824	1,764	1,712
Freeport 1-2, 1-3, & 2-3	21.5	(2.47)	19.03	345	17	84	45	1,953	1,855	1,808	1,748	1,696
Freeport 1-2	2.5	(0.37)	2.13	362	34	101	62	1,970	1,872	1,825	1,765	1,713
Freeport 1-3	3.0	(0.45)	2.55	361	33	101	62	1,970	1,872	1,824	1,764	1,712
Freeport 2-3	16.0	(1.65)	14.35	350	22	89	50	1,958	1,860	1,813	1,753	1,701
Charles P Killer 09 through 14	13.4	(1.77)	11.63	352	24	92	53	1,961	1,863	1,815	1,755	1,703
Charles P Keller 09	1.6	(0.21)	1.39	363	35	102	63	1,971	1,873	1,825	1,765	1,713
Charles P Keller 10	1.6	(0.21)	1.39	363	35	102	63	1,971	1,873	1,825	1,765	1,713
Charles P Keller 11	2.4	(0.32)	2.08	362	34	101	62	1,970	1,872	1,825	1,765	1,713
Charles P Keller 12	2.5	(0.33)	2.17	362	34	101	62	1,970	1,872	1,825	1,765	1,713
Charles P Keller 13	2.5	(0.33)	2.17	362	34	101	62	1,970	1,872	1,825	1,765	1,713
Charles P Keller 14	2.8	(0.37)	2.43	362	34	101	62	1,970	1,872	1,824	1,764	1,712
Wading River 1, 2, & 3	228.9	(23.62)	205.28	159	(169)	(102)	(141)	1,767	1,669	1,622	1,562	1,510
Wading River 1	77.4	(7.99)	69.41	295	(33)	34	(5)	1,903	1,805	1,757	1,697	1,645
Wading River 2	76.7	(7.92)	68.78	295	(33)	35	(4)	1,904	1,806	1,758	1,698	1,646
Wading River 3	74.8	(7.72)	67.08	297	(31)	36	(3)	1,905	1,807	1,760	1,700	1,648
Barrett ST 01 & 02	325.3	(35.30)	290.00	74	(254)	(187)	(226)	1,682	1,584	1,537	1,477	1,425
Barrett ST 01	144.3	(15.66)	128.64	235	(93)	(25)	(64)	1,844	1,746	1,698	1,638	1,586
Barrett ST 02	181.0	(19.64)	161.36	203	(125)	(58)	(97)	1,811	1,713	1,666	1,606	1,554
Barrett GT 01 through 12	259.4	(24.70)	234.70	129	(199)	(131)	(170)	1,738	1,640	1,592	1,532	1,480
Barrett GT 01	14.2	(1.47)	12.73	351	23	91	52	1,960	1,862	1,814	1,754	1,702
Barrett GT 02	14.3	(1.48)	12.82	351	23	91	52	1,960	1,862	1,814	1,754	1,702
Barrett 03	13.8	(1.42)	12.38	352	24	91	52	1,960	1,862	1,814	1,754	1,702
Barrett 04	15.1	(1.56)	13.54	351	22	90	51	1,959	1,861	1,813	1,753	1,701
Barrett 05	12.7	(1.31)	11.39	353	25	92	53	1,961	1,863	1,815	1,755	1,703
Barrett 06	14.0	(1.44)	12.56	351	23	91	52	1,960	1,862	1,814	1,754	1,702
Barrett 08	13.3	(1.37)	11.93	352	24	91	52	1,960	1,862	1,815	1,755	1,703
Barrett 09	40.4	(3.65)	36.75	327	(1)	67	28	1,936	1,838	1,790	1,730	1,678
Barrett 10	41.3	(3.73)	37.57	326	(2)	66	27	1,935	1,837	1,789	1,729	1,677

Long Island												
			Year	2026	2027	2028	2029	2030	2031	2032	2033	2034
Long Island Transmission Security Margin, Summer Peak - Baseline Expected Summer Weather, Normal Transfer Criteria (MW) (1)				364	36	103	64	1,972	1,874	1,827	1,767	1,715
Unit Name	Summer DMNC (MW)	NERC 5-Year Class Average De-Rate (MW)	Summer De-Rated Capability (MW)	Transmission Security Margin Considering Impact of Generator Outage (Retire, Mothball, IIFO)								
Barrett 11	40.0	(3.62)	36.38	328	(0)	67	28	1,936	1,838	1,790	1,730	1,678
Barrett 12	40.3	(3.64)	36.66	327	(1)	67	28	1,936	1,838	1,790	1,730	1,678
Northport 1, 2, 3, and 4	1,452.0	(157.54)	1,294.46	(930)	(1,258)	(1,191)	(1,230)	678	580	532	472	420
Northport 1	363.0	(39.39)	323.61	40	(288)	(220)	(259)	1,649	1,551	1,503	1,443	1,391
Northport 2	363.0	(39.39)	323.61	40	(288)	(220)	(259)	1,649	1,551	1,503	1,443	1,391
Northport 3	363.0	(39.39)	323.61	40	(288)	(220)	(259)	1,649	1,551	1,503	1,443	1,391
Northport 4	363.0	(39.39)	323.61	40	(288)	(220)	(259)	1,649	1,551	1,503	1,443	1,391
Port Jefferson GT 02 & 03	78.1	(8.06)	70.04	294	(34)	33	(6)	1,902	1,804	1,757	1,697	1,645
Port Jefferson GT 02	38.8	(4.00)	34.80	329	1	69	30	1,938	1,840	1,792	1,732	1,680
Port Jefferson GT 03	39.3	(4.06)	35.24	329	1	68	29	1,937	1,839	1,792	1,732	1,680
Port Jefferson 3 & 4	359.8	(39.04)	320.76	43	(285)	(217)	(256)	1,652	1,554	1,506	1,446	1,394
Port Jefferson 3	178.8	(19.40)	159.40	205	(123)	(56)	(95)	1,813	1,715	1,667	1,607	1,555
Port Jefferson 4	181.0	(19.64)	161.36	203	(125)	(58)	(97)	1,811	1,713	1,666	1,606	1,554
Hempstead (RR)	74.5	(8.08)	66.42	298	(30)	37	(2)	1,906	1,808	1,760	1,700	1,648
Glenwood GT 02, 04, & 05	126.9	(13.10)	113.80	250	(78)	(10)	(49)	1,859	1,761	1,713	1,653	1,601
Glenwood GT 02	48.3	(4.98)	43.32	321	(7)	60	21	1,929	1,831	1,784	1,724	1,672
Glenwood GT 04	38.4	(3.96)	34.44	330	2	69	30	1,938	1,840	1,792	1,732	1,680
Glenwood GT 05	40.2	(4.15)	36.05	328	(0)	67	28	1,936	1,838	1,791	1,731	1,679
Holtsville 01 through 10	510.1	(46.11)	463.99	(100)	(428)	(361)	(400)	1,508	1,410	1,363	1,303	1,251
Holtsville 01	53.0	(4.79)	48.21	316	(12)	55	16	1,924	1,826	1,779	1,719	1,667
Holtsville 02	52.0	(4.70)	47.30	317	(11)	56	17	1,925	1,827	1,780	1,720	1,668
Holtsville 03	46.9	(4.24)	42.66	321	(7)	61	22	1,930	1,832	1,784	1,724	1,672
Holtsville 04	50.9	(4.60)	46.30	318	(10)	57	18	1,926	1,828	1,781	1,721	1,669
Holtsville 05	49.4	(4.47)	44.93	319	(9)	58	19	1,927	1,829	1,782	1,722	1,670
Holtsville 06	52.7	(4.76)	47.94	316	(12)	55	16	1,924	1,826	1,779	1,719	1,667
Holtsville 07	50.0	(4.52)	45.48	319	(9)	58	19	1,927	1,829	1,781	1,721	1,669
Holtsville 08	49.6	(4.48)	45.12	319	(9)	58	19	1,927	1,829	1,782	1,722	1,670
Holtsville 09	52.3	(4.73)	47.57	316	(12)	56	17	1,925	1,827	1,779	1,719	1,667
Holtsville 10	53.3	(4.82)	48.48	316	(12)	55	16	1,924	1,826	1,778	1,718	1,666
Shoreham GT 3 & 4	82.7	(8.53)	74.17	290	(38)	29	(10)	1,898	1,800	1,753	1,693	1,641
Shoreham GT3	41.4	(4.27)	37.13	327	(1)	66	27	1,935	1,837	1,790	1,730	1,678
Shoreham GT4	41.3	(4.26)	37.04	327	(1)	66	27	1,935	1,837	1,790	1,730	1,678

Long Island												
			Year	2026	2027	2028	2029	2030	2031	2032	2033	2034
Long Island Transmission Security Margin, Summer Peak - Baseline Expected Summer Weather, Normal Transfer Criteria (MW) (1)				364	36	103	64	1,972	1,874	1,827	1,767	1,715
Unit Name	Summer DMNC (MW)	NERC 5-Year Class Average De-Rate (MW)	Summer De-Rated Capability (MW)	Transmission Security Margin Considering Impact of Generator Outage (Retire, Mothball, IIFO)								
East Hampton GT 01, 2, 3, & 4	23.5	(2.44)	21.06	343	15	82	43	1,951	1,853	1,806	1,746	1,694
East Hampton GT 01	18.1	(1.64)	16.46	348	20	87	48	1,956	1,858	1,810	1,750	1,698
East Hampton 2	1.8	(0.27)	1.53	363	34	102	63	1,971	1,873	1,825	1,765	1,713
East Hampton 3	1.8	(0.27)	1.53	363	34	102	63	1,971	1,873	1,825	1,765	1,713
East Hampton 4	1.8	(0.27)	1.53	363	34	102	63	1,971	1,873	1,825	1,765	1,713
Southold 1	9.8	(1.01)	8.79	355	27	95	56	1,964	1,866	1,818	1,758	1,706
S Hampton 1	8.1	(0.84)	7.26	357	29	96	57	1,965	1,867	1,820	1,760	1,708
Freeport CT 1 & 2	88.7	(9.15)	79.55	285	(44)	24	(15)	1,893	1,795	1,747	1,687	1,635
Freeport CT 1	45.7	(4.72)	40.98	323	(5)	62	23	1,931	1,833	1,786	1,726	1,674
Freeport CT 2	43.0	(4.44)	38.56	325	(3)	65	26	1,934	1,836	1,788	1,728	1,676
Flynn	139.5	(6.57)	132.93	231	(97)	(30)	(69)	1,839	1,741	1,694	1,634	1,582
Greenport GT1	54.5	(4.93)	49.57	314	(14)	54	15	1,923	1,825	1,777	1,717	1,665
Far Rockaway GT1 & GT2	68.4	(6.18)	62.22	302	(26)	41	2	1,910	1,812	1,765	1,705	1,653
Far Rockaway GT1	22.4	(2.02)	20.38	344	16	83	44	1,952	1,854	1,806	1,746	1,694
Far Rockaway GT2	46.0	(4.16)	41.84	322	(6)	62	23	1,931	1,833	1,785	1,725	1,673
Bethpage	46.0	(2.17)	43.83	320	(8)	60	21	1,929	1,831	1,783	1,723	1,671
Bethpage 3	75.0	(3.53)	71.47	293	(35)	32	(7)	1,901	1,803	1,755	1,695	1,643
Bethpage GT4	43.8	(4.52)	39.28	325	(3)	64	25	1,933	1,835	1,788	1,728	1,676
Stony Brook (BTM:NG)	0.0	0.00	0.00	364	36	103	64	1,972	1,874	1,827	1,767	1,715
Brentwood (3)	45.0	(4.64)	40.36	324	(4)	63	24	1,932	-	-	-	-
Pilgrim GT1 & GT2	84.9	(8.76)	76.14	288	(40)	27	(12)	1,896	1,798	1,751	1,691	1,639
Pilgrim GT1	42.0	(4.33)	37.67	326	(2)	66	27	1,935	1,837	1,789	1,729	1,677
Pilgrim GT2	42.9	(4.43)	38.47	326	(2)	65	26	1,934	1,836	1,788	1,728	1,676
Pinelawn Power 1 (2)	72.6	(3.42)	69.18	-	-	-	-	-	-	-	-	-
Caithness_CC_1	321.8	(15.16)	306.64	57	(271)	(203)	(242)	1,666	1,568	1,520	1,460	1,408
Islip (RR)	7.5	(0.81)	6.69	357	29	97	58	1,966	1,868	1,820	1,760	1,708
Babylon (RR)	15.8	(1.71)	14.09	350	22	89	50	1,958	1,860	1,813	1,753	1,701
Huntington (RR)	24.8	(2.69)	22.11	342	14	81	42	1,950	1,852	1,805	1,745	1,693

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