Short-Term Assessment of Reliability: 2025 Quarter 2

A Report by the
New York Independent System Operator

July 14, 2025

Table of Contents

Executive Summary

This report sets forth the 2025 Quarter 2 Short-Term Assessment of Reliability ("STAR") findings for the five-year study period of April 15, 2025, through April 15, 2030, considering forecasts of peak power demand, planned upgrades to the transmission system, and changes to the generation mix over the next five years. Included in this STAR is the ICAP Ineligible Forced Outage ("IIFO") of Gowanus Gas Turbine 3-6, Narrows Gas Turbine 2-1, and Narrows Gas Turbine 2-7. This assessment does not identify any Generator Deactivation Reliability Need due to the unavailability of these units. No new reliability needs are identified in this STAR.

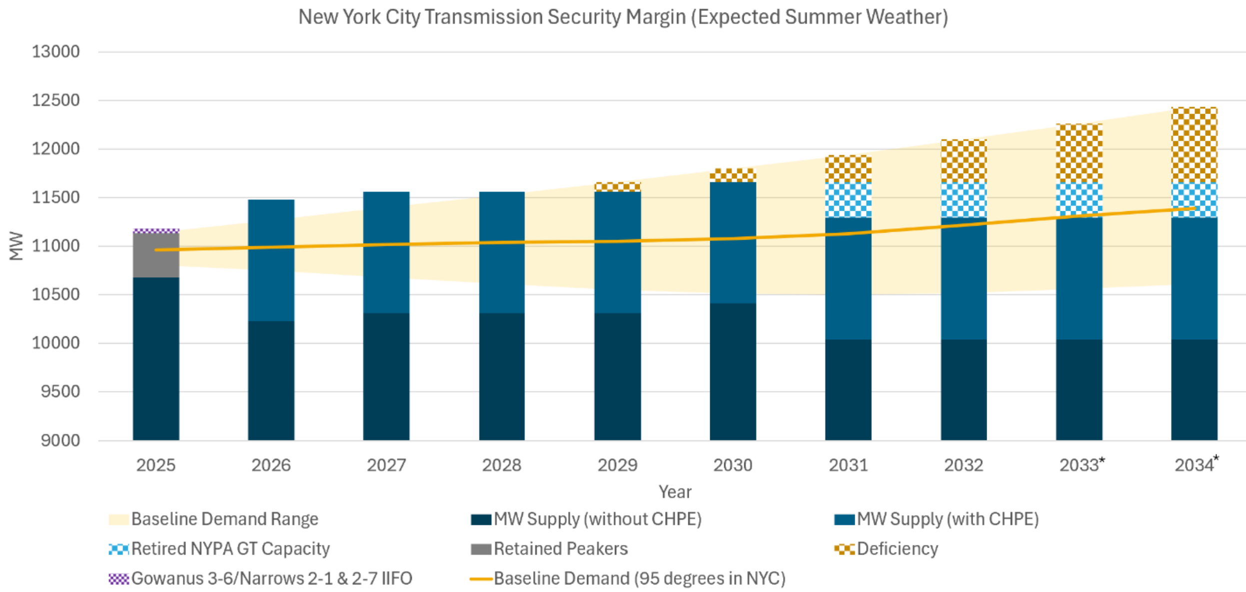
New York City Reliability Need

In the 2023 Quarter 2 STAR, the NYISO identified a short-term reliability need beginning in summer 2025 within New York City primarily driven by a combination of forecasted increases in peak demand and the assumed unavailability of certain generation in New York City affected by the "Peaker Rule."[1] Specifically, the 2023 Quarter 2 STAR identified that the New York City zone is deficient by as much as 446 MW for a duration of nine hours on the peak day during expected weather conditions when accounting for forecasted economic growth and policy-driven increases in demand. After accounting for the updated assumptions in this 2025 Quarter 1 STAR, the New York City zone is deficient by 281 MW for a duration of five hours to as much as 461 MW for a duration of seven hours with high demand. The deficiency may be greater depending on system performance as highlighted by the sensitivities evaluated for this STAR.

On November 20, 2023, following a solicitation for solutions, the NYISO issued a Short-Term Reliability Process Report[2] identifying the temporary and permanent solutions to the identified 2025 New York City need. The NYISO determined that temporarily retaining the peaker generators on the Gowanus 2 & 3 and Narrows 1 & 2 barges is necessary to address the need, and that the permanent solution is the Champlain Hudson Power Express ("CHPE") connection from Quebec, Canada to New York City, currently scheduled to enter service in spring 2026. With the continued operation of these peakers until the earlier of (a) the date a permanent solution (*i.e.,* CHPE) is in place and demonstrates dependable capacity supply during summer peak conditions or (b) May 2027, the need for the currently forecasted demand is addressed if CHPE is not delayed beyond 2026, as shown in the following chart. Without the retention of these generators, the New York City area would not meet the mandatory reliability criteria during expected summer weather peak demand periods.

[1] In 2019, the New York State Department of Environmental Conservation adopted a regulation to limit nitrogen oxides (NOx) emissions from simple-cycle combustion turbines, referred to as the "Peaker Rule" (here)

[2] https://www.nyiso.com/documents/20142/39103148/2023-Q2-Short-Term-Reliability-Process-Report.pdf



*The 2025 Q2 STAR baseline transmission security margin results are based on the 2024 Gold Book demand forecast. This chart does not use the same assumptions as the 2025-34 Comprehensive Reliabilty Plan as presented by NYISO at the May 6th, 2025 ESPWG/TPAS meeting, which shows no Reliability Need in 2033 and 2034, and that the NYISO determined that a solicitation for solutions is not required to address the Reliability Need identified in the 2024 RNA.The 2025 Q3 STAR baseline transmission security margin results are based on the 2025 Gold Book demand forecast.

The NYISO's designation of the Gowanus 2 & 3 and Narrows 1 & 2 generators has allowed their continued operation beyond May 2025 until permanent solutions are in place, for an initial period of up to two years (May 1, 2027). There is a potential for an additional two-year extension (to May 1, 2029) if reliability needs still exist, as provided by the DEC Peaker Rule. 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 Champlain Hudson Power Express project toward completion.

Considering the baseline results in this STAR and the heightened uncertainty of planned system conditions, the NYISO's designation of the Gowanus 2 & 3 and Narrows 1 & 2 generators to allow their continued operation under the Peaker Rule continues to be necessary to address the reliability need identified in the 2023 Quarter 2 STAR. Additionally, Con Edison's local analysis identifies that until the fourth Gowanus – Greenwood 345/138 kV PAR controlled feeder is placed into service, which is scheduled for May 2026, the Narrows and Gowanus generators are required to remain in service. The remaining Gowanus 2 & 3 and Narrows 1 & 2 units, allowing for the unavailability of Gowanus 3-6, Narrows 2-1, and Narrows 2-7, remain sufficient to address the identified BPTF and non-BPTF reliability needs.

Separate from the short-term process, the 2024 Reliability Needs Assessment ("RNA") published in December 2024 identified a reliability need associated with a deficiency in New York City beginning in summer 2033, growing to a deficiency of 97 MW for three hours on the peak day in 2034. This was primarily driven by a combination of forecasted increases in peak demand and the assumed future retirement of the NYPA small gas plants. Following consideration of updates to local transmission plans and demand forecasts in Q1, 2025, the NYISO found that the reliability need was eliminated and, therefore, the NYISO advised stakeholders on May 6, 2025, that a solicitation for solutions is not required to address the reliability need identified in the 2024 RNA. The NYISO is preparing the 2025-2034 Comprehensive Reliability Plan ("CRP"), which will include various scenarios that will inform the risks to reliability over the 10-year planning horizon.

Reliability Assessment

Included in this STAR are the generator deactivation assessments for the IIFO of Gowanus 3-6, Narrows 2-1, and Narrows 2-7. The NYISO performed a transmission security assessment of the BPTF and identified no new reliability needs during the STAR study period. Con Edison performed a deactivation assessment to evaluate the reliability of the local non-BPTF system. No generation deactivation needs were identified for the removal of these specific units.

Con Edison also shared a preliminary assessment of the NYC 345/138 kV transmission load area ("TLA") that considers peak conditions for each TLA. Con Edison's assessment indicates potential future local needs that are driven by increasing load. Con Edison reported that it is currently performing a more detailed power flow assessment as part of its 2025 Local Transmission Owner Plan ("LTP"), which is expected to be finalized by Q4 2025.

In addition to New York City, this assessment also evaluated the transmission security margins for the Lower Hudson Valley and Long Island localities. For these localities, the planned Bulk Power Transmission Facilities ("BPTF") through the study period are within applicable reliability criteria based on the baseline summer and winter coincident peak demand forecasts with expected weather and with the planned projects meeting their proposed in-service dates. The NYISO assessed the resource adequacy of the overall system and found no resource adequacy reliability needs.

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.

As generators that are subject to the DEC's Peaker Rule submit their Generator Deactivation Notices, the NYISO and the responsible Transmission Owners will continue to evaluate in future STARs whether Generator Deactivation Reliability Needs arise from the deactivation of Initiating Generators.[3]

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

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 Needs")[4] due to various changes to the grid such as generator deactivations, revised transmission plans, and updated demand forecasts. Transmission Owners also assess the impact of generator deactivations on their local systems. A Short-Term Reliability Need that is observed within the first three years of the study period constitutes a "Near-Term Reliability Need."[5] Should a Near-Term Reliability Need be identified in a STAR, the NYISO solicits and selects the solution to address the need. If a need arises beyond the first three years of the study period, the NYISO may choose to address the need within the STRP or, if time permits, through the long-term Reliability Planning Process.

This STAR report sets forth the 2025 Quarter 2 findings for the study period from the STAR Start Date (April 15, 2025) through April 15, 2030. The NYISO assessed the potential reliability impacts to the BPTF considering system changes, including the availability of resources and the status of transmission plans in accordance with the NYISO Reliability Planning Process Manual.[6]

Assumptions

The NYISO evaluated the study period using the most recent Reliability Planning Process base case and data available as of April 14, 2025 (*i.e.,* the day before the April 15, 2025 Q2 STAR start date). In accordance with the base case inclusion rules,[7] generation and transmission projects are added to the base case 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. The NYISO is tracking the progress of many projects that may contribute to grid reliability, including numerous offshore wind and energy storage facilities that have not yet met the inclusion rules for reliability assessments. These

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

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

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

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

additional tracked projects are listed in the *2024 Gold Book* and in Appendix D of the 2024 RNA.

This assessment used the major assumptions included in the 2024 RNA, along with several updates to key study assumptions which 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, 2025. The meeting materials are posted on the NYISO's website.[8]

Generation Assumptions

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.[9]

[8] Short-Term Assessment of Reliability: 2025 Q2 Key Study Assumptions, ESPWG/TPAS, May 6, 2025 (here)

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

Figure 1: 2025 Quarter 2 STAR Generator Deactivations

Generating Unit	Submitting Entity	PTID	Responsible Transmission Owner	Zone	Nameplate MW	Unit Type	Date of Completed Deactivation Notice	Retire/Mothball Outage/ICAP Ineligible Forced Outage (IIFO)	Proposed Deactivation/IIFO Date
Gowanus 3-6	Alpha Generation, LLC	24127	Con Edison	J	20	GT	-	IIFO	4/1/25
Narrows 2-1	Alpha Generation, LLC	24236	Con Edison	J	22	GT	-	IIFO	5/1/25
Narrows 2-7	Alpha Generation, LLC	24242	Con Edison	J	22	GT	-	IIFO	5/1/25

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").[10] Combustion turbines known as "peakers" typically operate to maintain bulk power system reliability during the most stressful operating conditions, such as periods of peak electricity demand. The Peaker Rule impacts turbines located mainly in the lower Hudson Valley, New York City and Long Island. Many of these units also maintain transmission security by supplying energy within certain areas of the grid referred to as "load pockets." Load pockets represent transmission-constrained geographic areas where a portion of electrical demand can only be served by local generators due to transmission limitations that occur during certain operating conditions.

The Peaker Rule provides a phased reduction in emission limits, in 2023 and 2025, during the ozone season (May 1-September 30) and allows several options for achieving compliance with the new lower limits applicable during the ozone season. The rule required peaking unit owners to submit compliance plans to the DEC in March 2020. Compliance plans submitted to the DEC were provided to the NYISO for assessment and inclusion in the Reliability Planning Process base case. Considering all peaker unit compliance plans, approximately 1,600 MW of peaker generation capability would be unavailable during the summer by 2025 to comply with the emissions requirements. A subset of those generators became unavailable starting in 2023. As of May 1, 2023, 1,014 MW of affected peakers deactivated or limited their operations. The remaining peakers would have become unavailable beginning May 1, 2025, except for those that have been designated as necessary to be temporarily retained for reliability until permanent, Climate Leadership and Community Protection Act[11] compliant, solutions are developed or completed. Remaining peaker units have stated either that they comply with the emission limits as currently operated, or proposed equipment upgrades to achieve the more stringent emissions limits.

A list of peaker generation removals is provided in Figure 2. Peaker generators that have already completed a Generator Deactivation Notice or entered an IIFO are indicated in the table. Additionally, the table notes the STAR study or other assessments where these generators have been evaluated once a generator completed its generator deactivation notice or entered into an IIFO.

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

[10] DEC Peaker Rule

[11] New York's Climate Leadership and Community Protection Act ("CLCPA"), Chapter 106 of the Laws of 2019. The CLCPA become effective on January 1, 2020.

designated by the NYISO or by the local transmission owner as needed to resolve a reliability need until a permanent solution is in place. Consistent with the DEC's regulations and detailed in the Short-Term Reliability Process report it issued on November 20, 2023, the NYISO has designated the Gowanus 2 & 3 and Narrows 1 & 2 generators (32 units total) to temporarily continue operation beyond May 2025 until permanent solutions are in place, for an initial period of up to two years (May 1, 2027).This STAR includes the unavailability of three of the 32 Gowanus and Narrows generators (Gowanus GT 3-6, Narrows GT 2-1, and Narrows GT 2-7), which are in an IIFO.

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

Figure 2: Status Changes Due to DEC Peaker Rule

Owner/Operator	Station	Zone	Nameplate (MW)	CRIS (MW) (1)		Capability (MW) (1)		Status Change Date (2)	STAR Evaluation or Other Assessment
				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	2/28/2021 (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	G	21.6	21.6	26.0	19.7	22.7	12/31/2025 (8)	2024 Q1
Central Hudson Gas & Elec. Corp.	South Cairo	G	21.6	19.8	25.9	14.6	20.7	3/31/2024 (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	5/1/2023	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) (4)	K	55.0	54.7	71.5	52.0	65.9	5/1/2023	
National Grid	Northport GT (9)	K	16.0	13.8	18.0	8.3	12.7	5/1/2023	
National Grid	Port Jefferson GT 01 (9)	K	16.0	14.1	18.4	13.0	15.3	5/1/2023	
National Grid	Shoreham 1 (3) (4)	K	52.9	48.9	63.9	42.0	63.0	5/1/2023	
National Grid	Shoreham 2 (3) (4)	K	18.6	18.5	23.5	17.4	21.5	5/1/2025	2025 Q1
Astoria Generating Company, L.P.	Astoria GT 01 (11)	J	16.0	15.7	20.5	13.8	17.6	5/1/2025 (11)	2024 Q3
Consolidated Edison Co. of NY, Inc.	59 St. GT 1 (10)	J	17.1	15.4	20.1	13.9	17.4	5/1/2025	
NRG Power Marketing, LLC	Arthur Kill GT 1 (10)	J	20.0	16.5	21.6	12.3	15.8	5/1/2025	
Astoria Generating Company, L.P.	Gowanus 2-1 through 2-8 (5) (13)	J	160.0	152.8	199.6	140.9	179.1	5/1/2025	
Astoria Generating Company, L.P.	Gowanus 3-1 through 3-8 (5) (13) (14)	J	140.0	129.2	168.7	122.9	157.7	5/1/2025	
Astoria Generating Company, L.P.	Gowanus 3-6 (5) (13)	J	20.0	17.6	23.0	15.6	20.8	4/1/2025 (IIFO)	2025 Q2
Astoria Generating Company, L.P.	Narrows 1-1 through 2-8 (5) (13) (15)	J	308.0	269.0	351.3	247.0	318.1	5/1/2025	
Astoria Generating Company, L.P.	Narrows 2-1 and 2-7 (5) (13)	J	44.0	40.1	52.3	37.3	47.6	5/1/2025 (IIFO)	2025 Q2
	Prior to Summer 2022		112.0	92.6	120.3	78.0	112.2		
	Prior to Summer 2023		1,174.3	1,066.0	1,348.8	936.0	1,228.7		
	Prior to Summer 2025		725.1	656.3	857.1	603.7	774.1		
	Total		2,011.4	1,814.9	2,326.2	1,617.7	2,115.0		

Notes

1. MW values are from the 2024 Load and Capacity Data Report except where the 2024 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. Generator changed DEC peaker rule compliance plan as compared to the 2020 RNA and all STARs prior to 2021 Q3.

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. These units have indicated they will be out-of-service during the ozone season (May through September) in their compliance plans in response to the DEC peaker rule.

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.

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 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.

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 or blackstart only.

11. The initial proposed retirement was on or after May 1, 2023, and was studied in the 2022 Q4 STAR. However, the unit modified its Peaker Rule compliance plan to be available for operation through May 1, 2025. The unit has submitted a new generator deactivation notice with a new proposed retirement date by May 1, 2025.

12. The retirement for this unit was evaluated in the 2023 Q3 STAR.

13. To address the Need identified in the 2023 Q2 STAR, the NYISO designated the generators on the Gowanus 2 & 3 and Narrows 1 & 2 barges to temporarily remain in operation after the DEC Peaker Rule compliance date (May 1, 2025) until permanent solutions to the Need are in place, for an initial period of up to two years (May 1, 2027).

14. Does not include Gowanus 3-6.

15. Does not include Narrows 2-1 and 2-7.

Generator Return-to-Service

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

Generator Additions

There are no generation additions beyond those included in the 2024 RNA. A list of generator additions, including updates to planned commercial operation dates as included in the 2024 RNA, is provided in Appendix C.

Demand Assumptions

The NYISO used the demand forecasts for this assessment consistent with the 2024 Gold Book. There are no changes to load beyond those included in the 2025 Q1 STAR.

The demand forecasts from the 2025 Gold Book will be utilized for the baseline transmission security margins in the 2025 Q3 STAR.

Figure 3 shows the summer and winter coincident peak demand forecast and the annual energy forecast for the STAR study period.

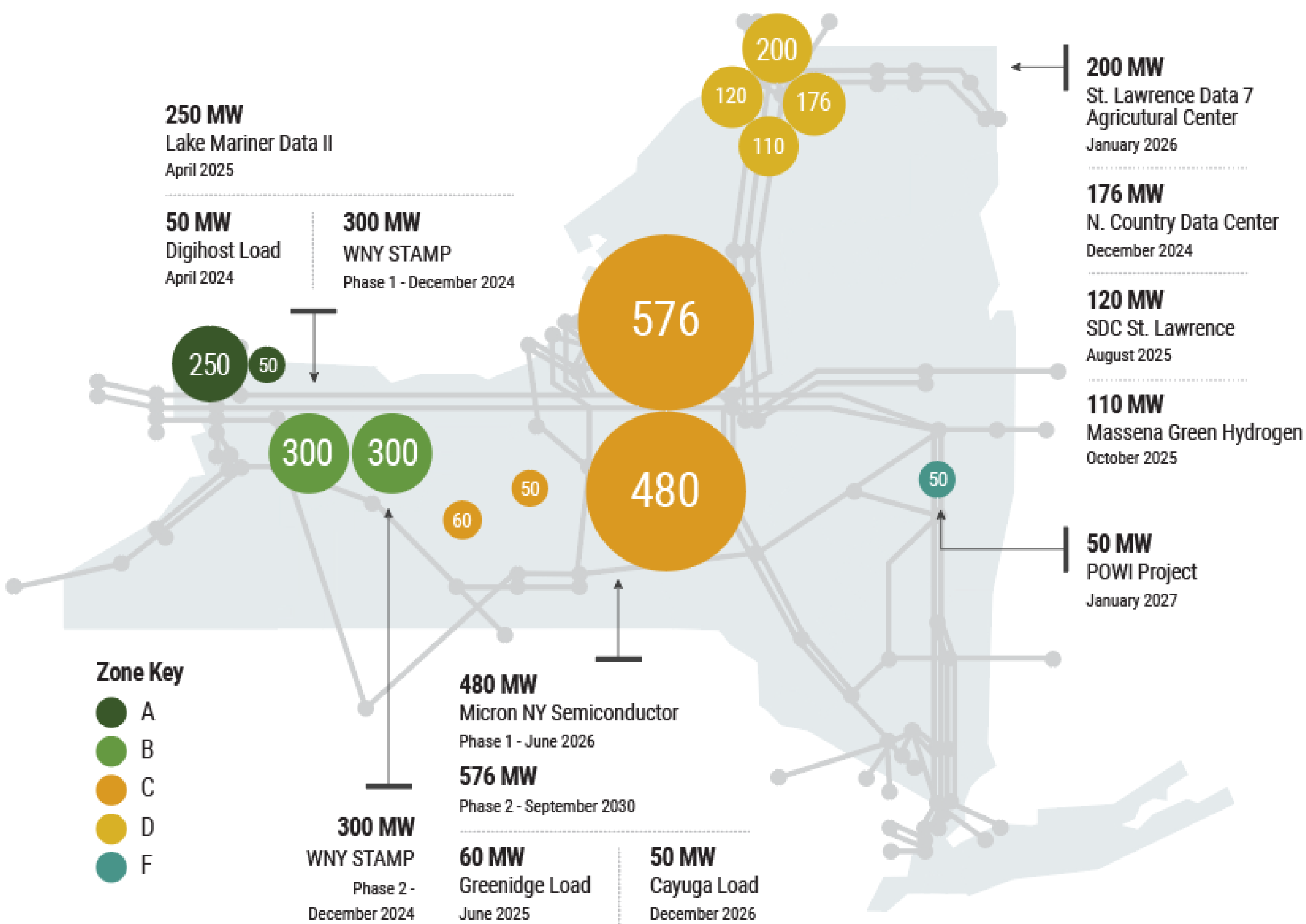
Figure 3: NYCA Demand Forecasts (2024 Gold Book)

Baseline Summer Coincident Peak Demand Forecast (MW)												
Year	A	B	C	D	E	F	G	H	I	J	K	NYCA
2025	2,821	1,969	2,559	689	1,317	2,273	2,157	615	1,334	10,960	4,956	31,650
2026	2,853	2,000	2,598	946	1,276	2,229	2,167	620	1,341	10,990	4,955	31,975
2027	2,835	1,993	2,612	1,250	1,238	2,235	2,183	625	1,351	11,020	4,968	32,310
2028	2,799	1,968	2,639	1,251	1,222	2,225	2,209	632	1,363	11,040	4,982	32,330
2029	2,770	1,951	2,790	1,254	1,218	2,225	2,251	642	1,380	11,050	5,009	32,540
Baseline Winter Coincident Peak Demand Forecast (MW)												
Year	A	B	C	D	E	F	G	H	I	J	K	NYCA
2025-26	2,283	1,584	2,481	1,022	1,292	1,922	1,524	508	885	7,410	3,299	24,210
2026-27	2,348	1,626	2,587	1,304	1,289	1,931	1,548	512	896	7,490	3,334	24,865
2027-28	2,402	1,647	2,675	1,458	1,304	2,001	1,591	522	914	7,560	3,396	25,470
2028-29	2,444	1,670	2,797	1,459	1,323	2,037	1,640	532	933	7,660	3,465	25,960
2029-30	2,499	1,700	2,941	1,463	1,349	2,083	1,700	537	955	7,770	3,553	26,550
Baseline Annual Energy Forecast (GWh)												
Year	A	B	C	D	E	F	G	H	I	J	K	NYCA
2025	15,960	10,000	14,590	5,850	7,010	11,030	9,230	2,740	5,530	49,210	19,870	151,020
2026	16,100	10,330	14,810	7,380	6,740	10,780	9,280	2,740	5,560	49,290	19,980	152,990
2027	15,950	10,310	14,890	8,640	6,530	10,730	9,380	2,760	5,610	49,560	20,170	154,530
2028	15,750	10,100	15,260	8,650	6,390	10,770	9,510	2,780	5,670	49,830	20,390	155,100
2029	15,670	9,990	16,160	8,680	6,320	10,730	9,690	2,830	5,750	50,170	20,670	156,660

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, as well as hydrogen production operations (i.e., electrolysis).

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 has 19 projects requesting to interconnect for a combined total of over 3,000 MW of load.[13] 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 scenario, with the high demand forecast including more than the baseline forecast. Figure 4 highlights the majority of large loads with active requests in the NYISO Interconnection Queue (the figure does not include some of the more-recent load interconnection projects).

Figure 4: Large Load Projects in the NYISO Interconnection Queue



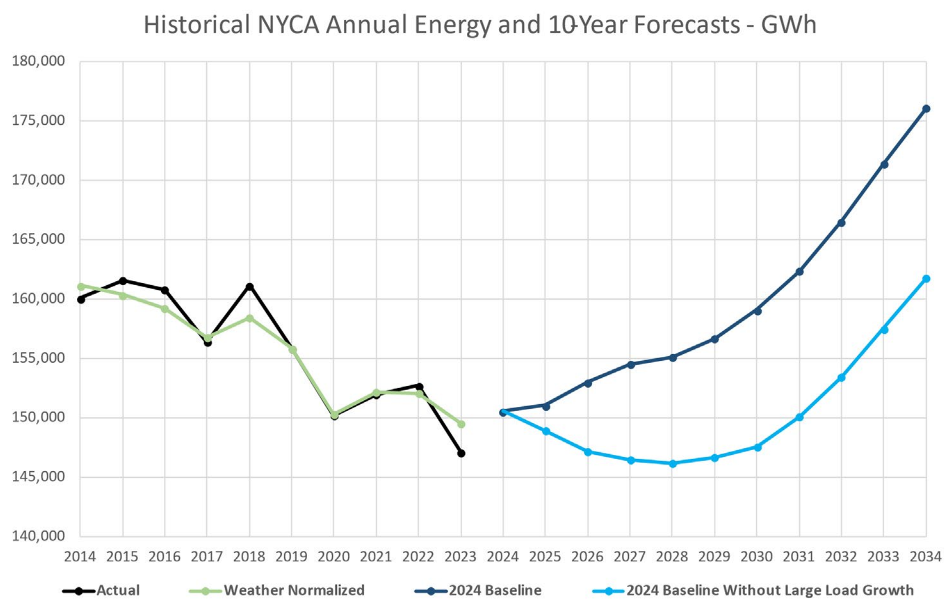
[12] Load interconnections that are subject to the NYISO's procedures include requests that are either (a) greater than 10 MW connecting a voltage level of 115 kV or above or (b) 80 MW or more connecting at a voltage level below 115 kV. Loads that do not meet one of the aforementioned criteria are handled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

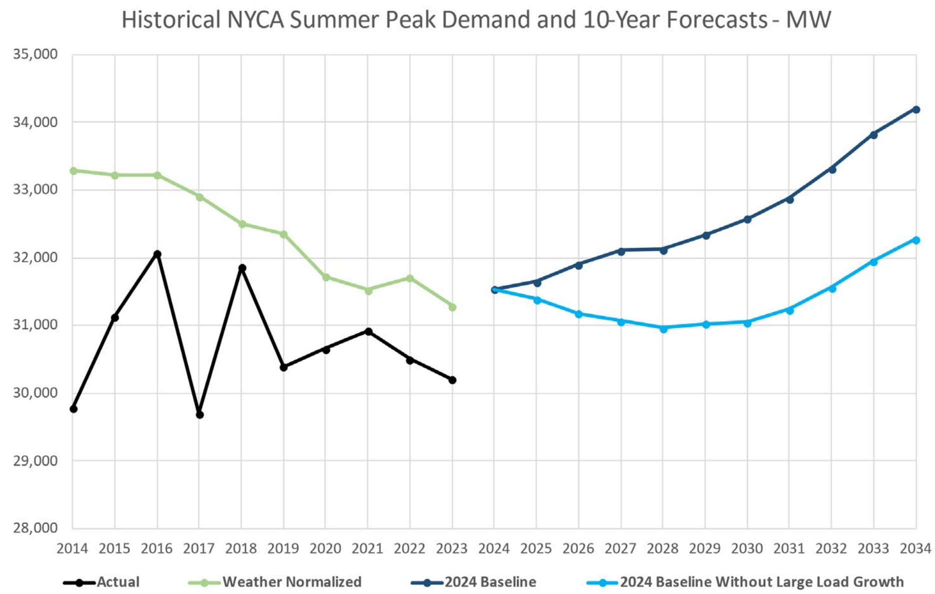
[13] NYISO Interconnection Queue, accessed September 2024, Interconnection Queue Spreadsheet.

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. While the RNA included these large loads in the Base Case, there could be differences in the actual large loads that ultimately interconnect to the system.

The impact of large load assumptions on the forecast is significant. Figure 5 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 5: Large Load Impact on NYCA Baseline Load Forecast (2024 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.

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.

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 1,200 MW of large load reduction during the summer and winter peak periods by 2027.

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.

This assessment recognizes that there is uncertainty in the demand forecast 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. These risks are considered in the transmission security margin calculations by incorporating the lower and higher bounds as a range of forecasted conditions during expected weather, which are specified in the Gold Book as the higher and lower demand forecasts. The lower and higher demand scenarios reflect achievement of policy targets through alternative pathways and assume the same weather factors as the baseline demand forecast. Figure 6 shows the range of baseline forecast along with the demand for heatwave and extreme heatwave conditions within the New York City locality. Figure 7 provides the same forecast information but for all of New York. The dominant policy driver in the early forecast years is energy efficiency, with significant state energy savings targets set through 2025 and 2030.

Figure 6: New York City Demand Forecasts (2024 Gold Book)

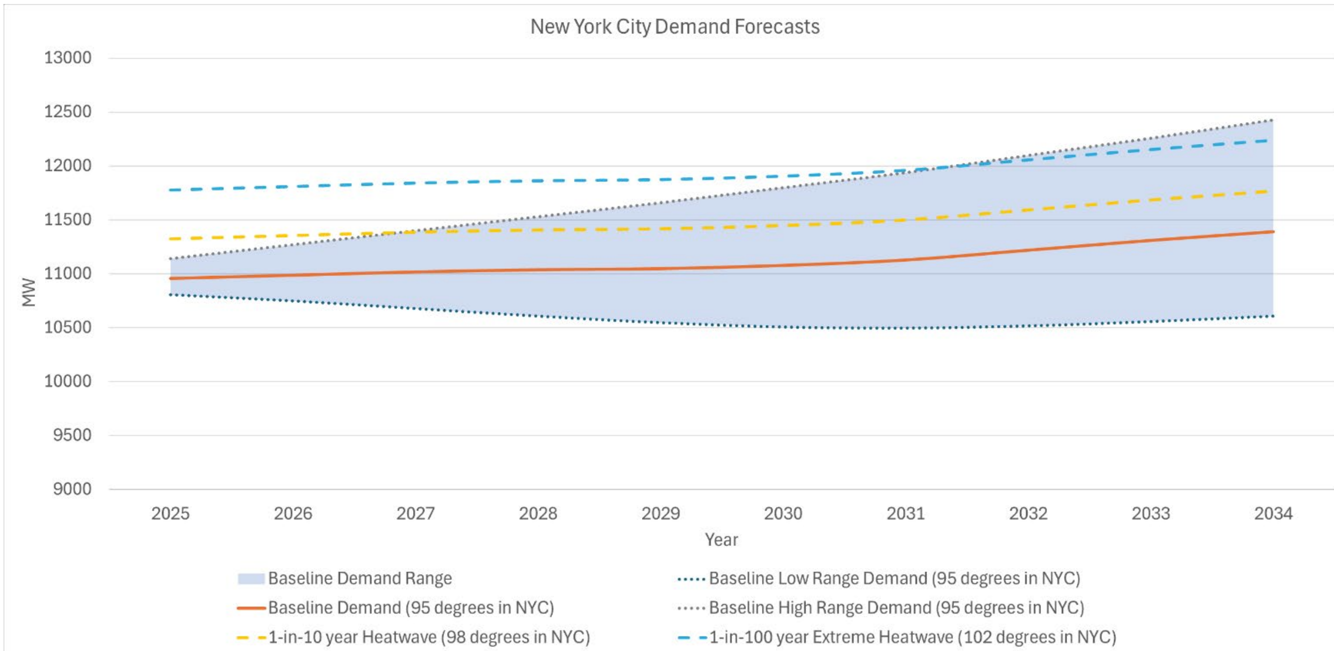
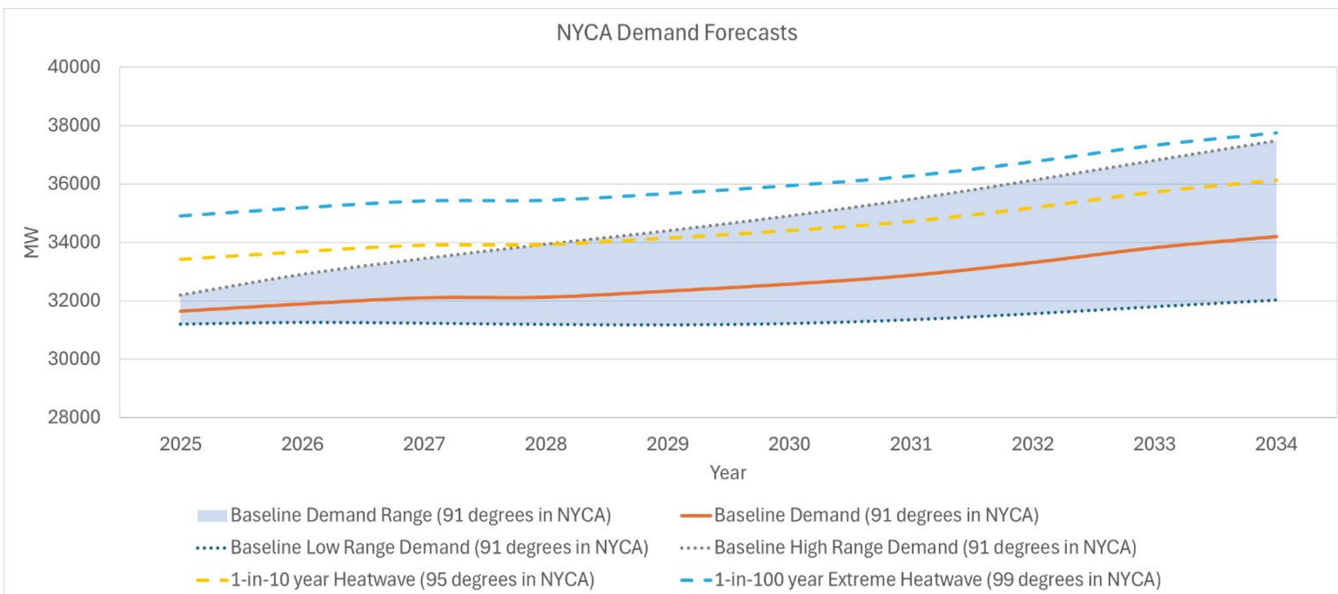


Figure 7: NYCA Demand Forecasts (2024 Gold Book)



Transmission Assumptions

Existing Transmission

The transmission assumptions utilized in this assessment are similar to those used for the 2024 RNA. Figure 8 lists the existing transmission outage assumptions.

A complete list of existing transmission facilities that are modeled as out-of-service for this assessment is also provided in Appendix C.

Figure 8: Transmission Assumptions

From	To	kV	ID	Out-of-Service Through	
				Prior STAR	Current STAR
Marion	Farragut	345	B3402	Long-Term	
Marion	Farragut	345	C3403	Long-Term	
Plattsburgh (1)	Plattsburgh	230/115	AT1	3/2025	9/2025
Stolle Rd	Stolle Rd	115	T11-52	6/2025	
Station 23	Station 42	115	920	12/2025	
Farragut		345	8E	-	11/2025
Farragut		345	9E	-	11/2025

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

Proposed Transmission

Compared to the 2024 RNA, there are no changes to assumed firm transmission facilities, as captured in Section 7 of the 2024 Gold Book. Details of the proposed transmission assumptions included in the 2024 RNA are provided in Appendix C.

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.

Starting with the 2022 RNA and included in subsequent STARs (including this STAR), enhancements to the application of reliability rules were employed for both transmission security and resource adequacy:

- For transmission security, to represent that not all generation will be available at any given time, a derating factor is applied to thermal units. Additionally, intermittent, weather dependent generation is dispatched according to its expected availability coincident with the represented system condition. The enhancements also include the ability to identify BPTF reliability needs in instances where the transmission security margin for a constrained area of the system is less than zero MW.
- For resource adequacy, to ensure that some level of operating reserves is maintained, the emergency operating procedure ("EOP") step will retain 400 MW of operating reserves at the time of a load shedding event.

As explained below, this assessment finds that reliability criteria would not be met for the BPTF throughout the five-year study period under the study assumptions and forecasted base case system conditions. However, the observed reliability violation in New York City is mitigated by the temporary and permanent solutions identified in the Short-Term Reliability Process Report issued November 20, 2023.

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.[16]

[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,

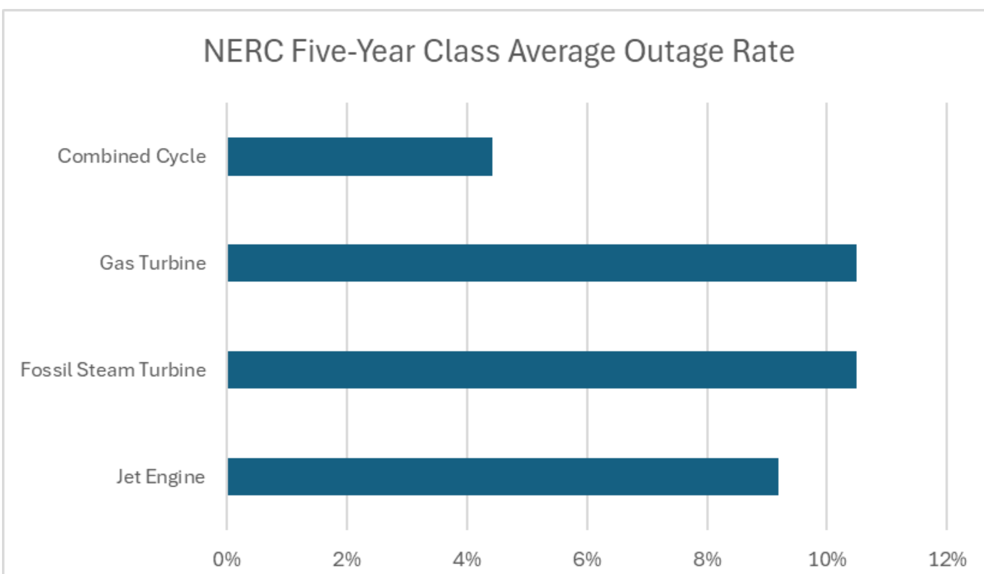
[16] At its June 23, 2022, meeting, the NYISO Operating Committee approved revisions to the Reliability Planning Process Manual that reflect the use of transmission security margins and other enhancements.

For the transmission security margin assessment, margins are evaluated for the statewide system margin, as well as Lower Hudson Valley, New York City, and Long Island localities. This evaluation will identify a BPTF reliability when the margin is less than zero under expected weather, normal transfer criteria conditions for the Lower Hudson Valley, New York City, and Long Island localities. Additional details regarding the impact of heatwaves, cold snaps, and other system conditions are provided in Appendix E.

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.[17] Derates for thermal generation are included due to the aging fleet without expected replacement, while the share of intermittent, weather dependent, generation is growing.

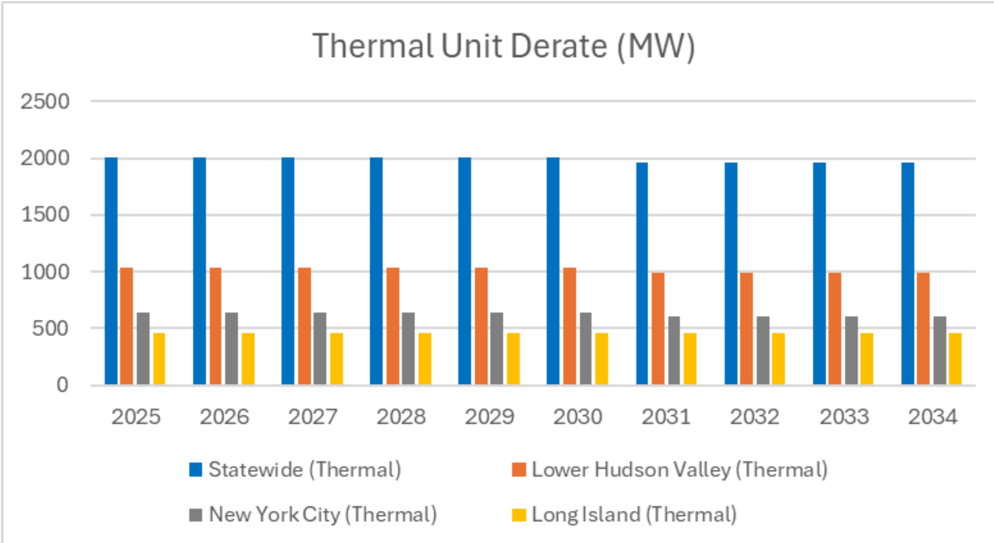
Figure 9 shows the NERC five-year class-average outage rate for combined cycle, gas turbine, fossil steam turbine, and jet engine generators. Figure 10 shows the impact of the thermal derates on the total resources available statewide, as well as the Lower Hudson Valley, New York City, and Long Island localities in the summer. Reductions in thermal derates over time are driven by the assumed generator deactivations in this assessment.

Figure 9: NERC Five-Year Class Average Outage Rate



[17] 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.

Figure 10: Thermal Unit Derate (MW) for New York



The NYISO performed a transmission security assessment of the BPTF and identified no new reliability needs during the STAR study period.

Steady State Assessment

There are three potential steady state reliability issues; two potential issues were identified in winter peak conditions and one in summer peak conditions. The identified issues do not result in a Reliability 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, including daytime light load conditions, which captured a high penetration of behind-the-meter solar resources.

The first identified steady-state transmission security issue is a low-voltage violation at the Porter 115 kV bus following various contingency combinations resulting in the loss of both Edic-to-Porter 345/115 kV transformers under expected winter peak conditions. This violation was first observed in the 2022 Quarter 3 STAR. The low-voltage violation at the Porter 115 kV bus is observed starting in winter 2025-26 due to (1) the retirement of the two Porter 230/115 kV buses, which is planned to occur that winter with the Smart Path Connect Project (interconnection queue #Q1125), and (2) the increasing demand in Zone E observed in winter. The evaluation did not observe the low-voltage violation at the Porter 115 kV bus under summer peak demand conditions because the demand forecast for Zone E is higher in winter than in summer. The low-voltage violation that is observed at the Porter 115 kV bus occurs due to the planned changes with the interconnection of the Smart Path Connect Project (Q#1125). The Q#1125 Facilities Study identified that the 230 kV Edic-Porter Line 17 will be retained along with other modifications to address this issue.

The second potential steady-state transmission security issue identified for the study period under expected winter 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 and is impacted by the inclusion of Q1213- St Lawrence Data and Agricultural Center in the2025 Q1 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 issue is driven by the growth of the North Country Data Center ("NCDC") load and the addition of St Lawrence Data and Agricultural Center, combined with the increasing demand in Zone D observed in winter, and the unavailability of non-firm gas generation in the local area. 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. 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.

The third potential steady-state transmission security issue identified for the study period under expected summer peak conditions is a thermal violation on the Lovett 345/138 kV transformer (Bank 192). This transformer entered service in October 2024 with installed ratings lower than what had been provided for planning purposes. Subsequent to the transformer going in-service, Orange & Rockland developed a modification to the station protection system to automatically isolate the transformer for overload conditions. This protection change was reflected in steady-state simulation by tripping the transformer when overloaded and no adverse impacts were observed on the BPTF.[18]

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.

[18] For information: A portion of load in Orange & Rockland's non-BPTF service territory including the RECO load in New Jersey, which is served radially from the NYCA, may be lost under N-1-1 conditions for contingency combinations that result in the loss of three transmission paths into this load pocket, which includes the loss of a double circuit tower. These contingency combinations are beyond design criteria for non-BPTF, and this risk of load loss existed before the Lovett transformer entered service. As such, there are no thermal criteria violations identified.

Short Circuit Assessment

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

Statewide System Margins

The statewide system margin is a measure of the amount of generation and net imports available to supply firm load with the bulk power transmission system within applicable normal ratings and limits (i.e., normal transfer criteria) while maintaining 10-minute operating reserves. Statewide system margin is a useful metric that respects multiple reliability criteria, but there is currently not a specific reliability criterion about statewide system margin.

Under summer peak baseline expected weather load, normal transfer criteria, the statewide system margin ranges between 1,064 MW in 2025 to -12 MW in 2034 with flexible large loads modeled offline. When flexible large loads are modeled online during the summer peak day, the statewide system margin ranges between 453 MW in 2025 to –1,192 MW in 2034. Under winter peak baseline expected weather load, normal transfer criteria, the statewide system margin ranges between 4,221 MW in 2025 to -2,283 MW in 2034 with flexible large loads modeled offline. When flexible large loads are modeled online during the winter peak day, the statewide system margin ranges between 453 MW in 2025 to –1,192 MW in 2034. The addition of Q1213 - St Lawrence Data and Agricultural Center (Zone D), as modeled in the 2025 Q1 STAR and this 2025 Q2 STAR, further reduces the statewide system margin by 200 MW by 2027.

The statewide system margin under summer peak baseline expected weather load is shown in Figure 11 and under winter peak baseline expected weather load in Figure 12.

Figure 11: Statewide System Margin – Summer Peak

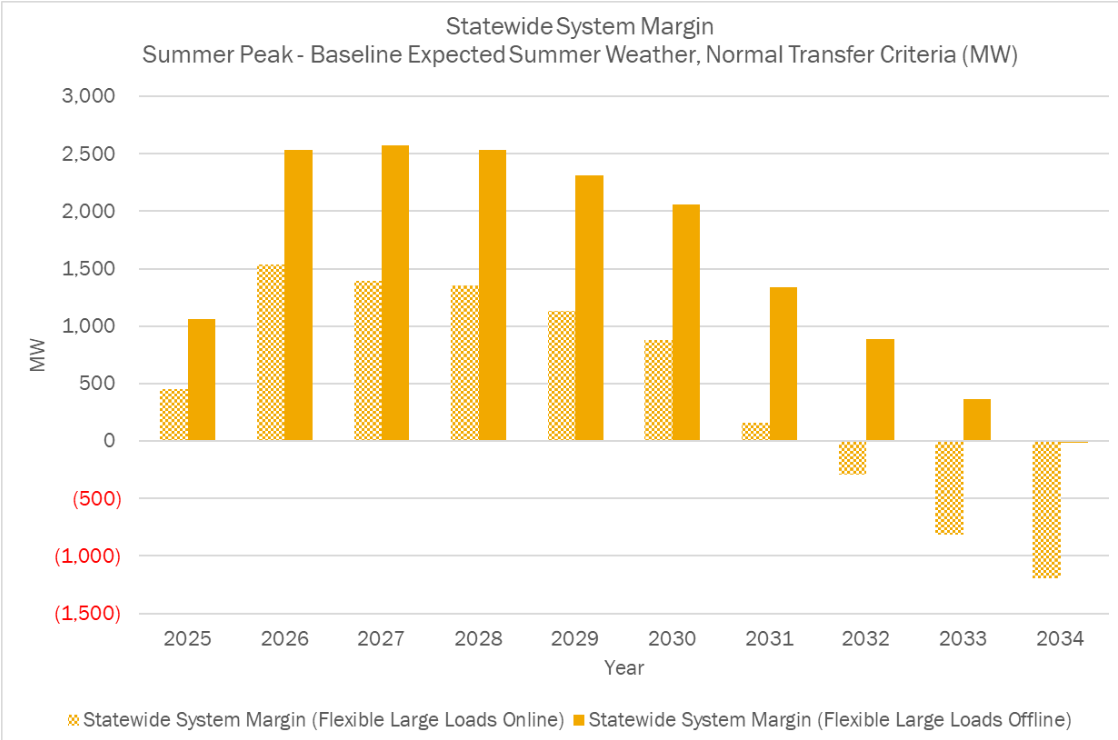
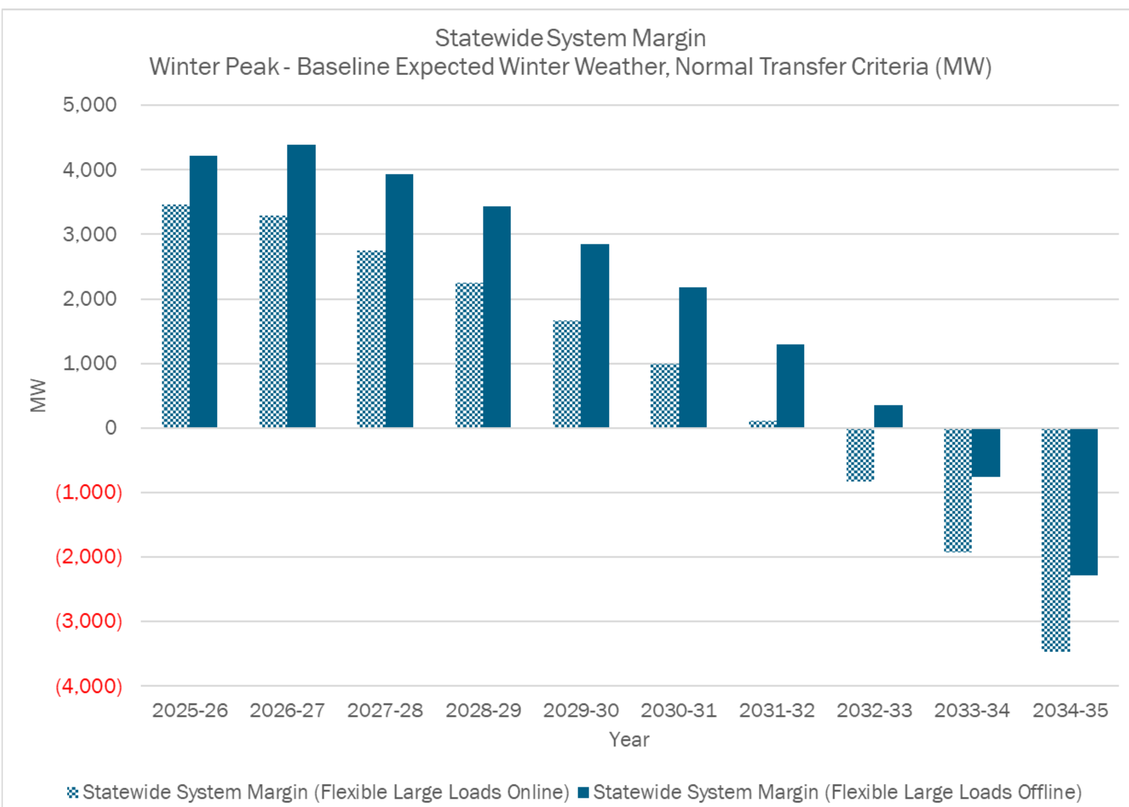


Figure 12: Statewide System Margin – Winter Peak

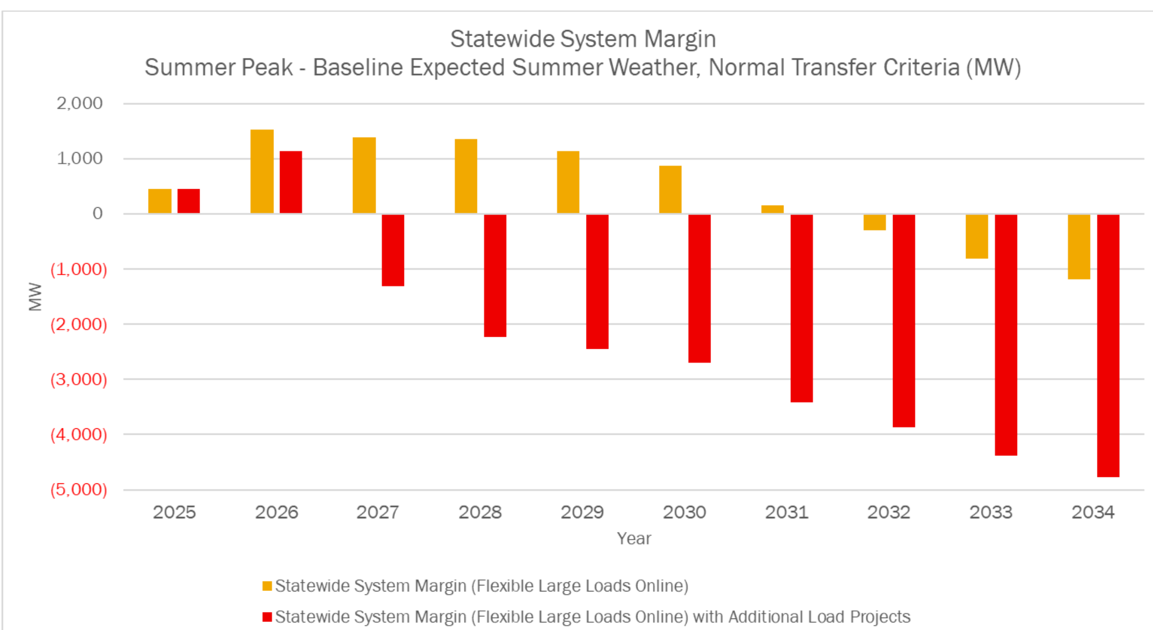


The decreasing statewide system margin in both summer and winter can be attributed to increasing demand that is not matched by sufficient planned resources. Additionally, the unavailability of non-firm gas is a key driver of deficient statewide margins in the winter peak condition. A negative statewide system margin is not, on its own, a reliability criteria violation. It is, however, a leading indicator of the inability to securely meet system load under applicable normal transfer criteria, which is observed in the RNA transmission security results as described in Appendix F to the 2024 RNA.

Further risks to the statewide system margin, and transmission security margins in the Lower Hudson Valley, New York City, and Long Island localities include: (1) the CHPE project experiences a significant delay, (2) additional power plants become unavailable, (3) demand significantly exceeds current forecasts.

The rapid increase of interconnection requests for load projects cannot be accounted for in demand forecasts and poses a risk to reliability. As of July 1, 2025, there is over 3,500 MW of additional requested load interconnection projects in the NYISO interconnection queue compared to the large loads included in the baseline forecast for this Q2 STAR. Figure 13 below shows the statewide system margin for summer peak conditions with the additional load projects and with flexible large loads modeled online. For this sensitivity, it is assumed that the requested load would be drawing full power on the proposed in-service date and phased in-service plans were not considered. The statewide system margin becomes deficient in 2027 by about 1,300 MW.

Figure 13: Statewide System Margin – Summer Peak with Additional Load Projects



Appendix E contains additional details of the margin calculations. Appendix E also shows impacts on the margin of heatwaves, cold snaps, plant outages, and other system conditions.

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. 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). Figure 14 provides a summary of the margins for normal transfer criteria at the baseline and high demand forecasts during expected summer weather. Figure 15 provides a summary of the margins for normal transfer criteria at the baseline forecasts during expected winter weather.

Figure 14: Statewide System Margin and Transmission Security Margins – Summer Peak

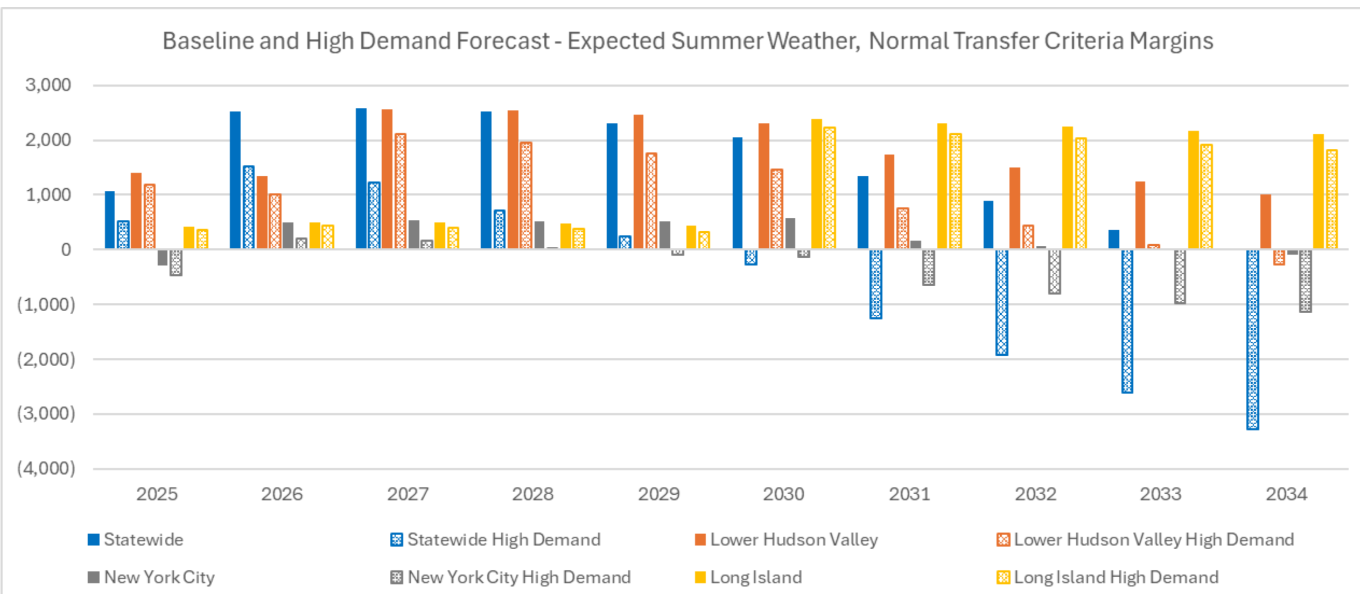
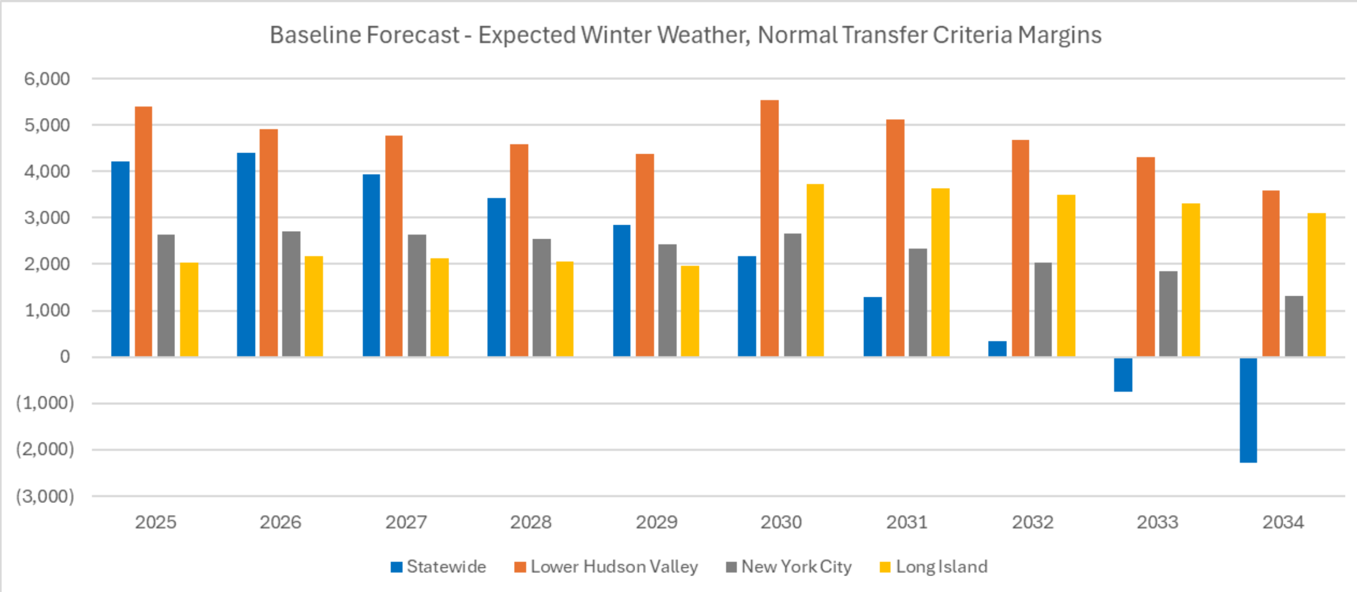


Figure 15: Statewide System Margin and Transmission Security Margins – Winter Peak



Based on the assumptions for this STAR, the margins are sufficient in the Lower Hudson Valley and Long Island localities in both summer and winter on the peak day during expected weather conditions for all years.

New York City Transmission Security Margin Baseline

The margin within New York City in 2025 would be deficient by 281 MW for a duration of five hours on the summer peak day during expected weather conditions if all of the Gowanus and Narrows peaker generators are unavailable. The New York City margin is shown in Figure 16. The hourly New York City margin for the peak day in 2025 is shown in Figure 17. Accounting for uncertainties in key demand forecast assumptions, using the higher bound of expected demand under baseline weather conditions (95 degrees Fahrenheit) in 2025, the margin within New York City would be deficient by as much as 461 MW for a duration of seven hours. With the planned addition of CHPE, there is an increase in the observed margin beginning summer 2026. However, the margin gradually erodes following CHPE's addition as the baseline demand grows throughout New York. As shown in Figure 16, by 2033, the margin within New York City is deficient by 17 MW during the peak hour, and by 2034 is deficient by 97 MW during the peak hour.

The deficient margin is primarily due to the increased demand forecasts within New York City combined with the unavailability of simple-cycle combustion turbines to comply with the DEC's Peaker Rule in 2025. Decreased summer capabilities of generators within the area and increased generator forced outage rates also contribute to the deficiency.

Figure 16: New York City Margin – Summer Peak

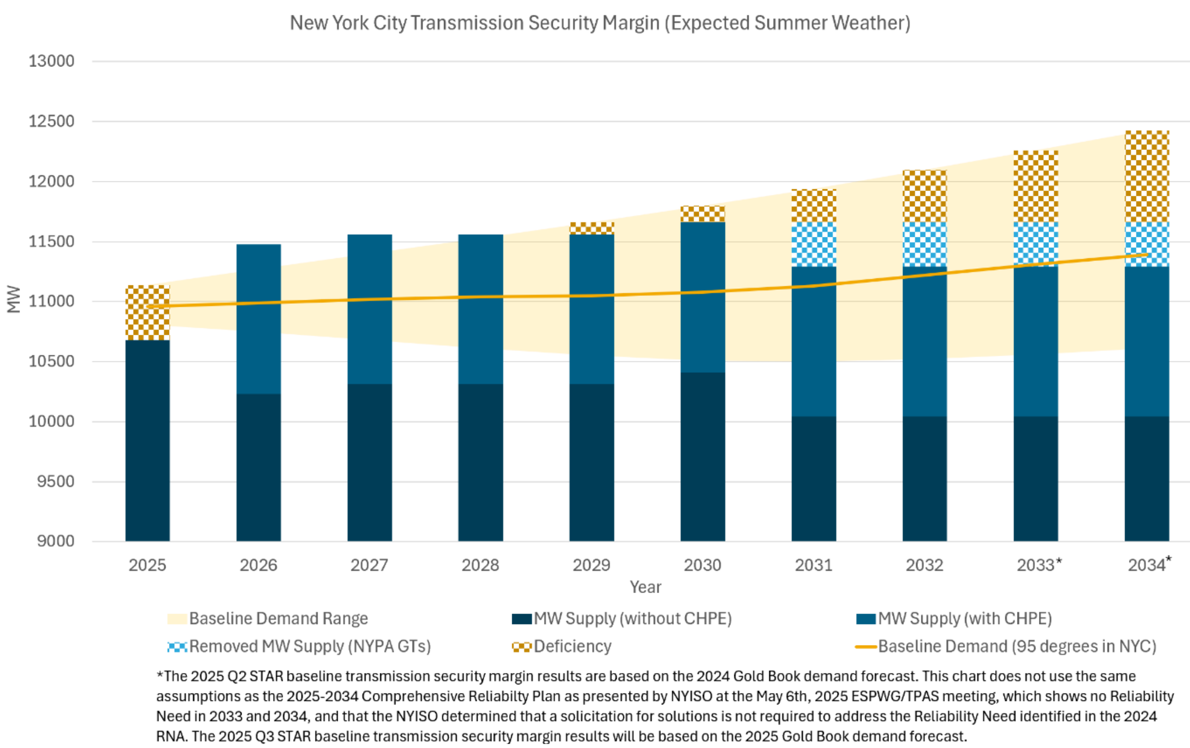
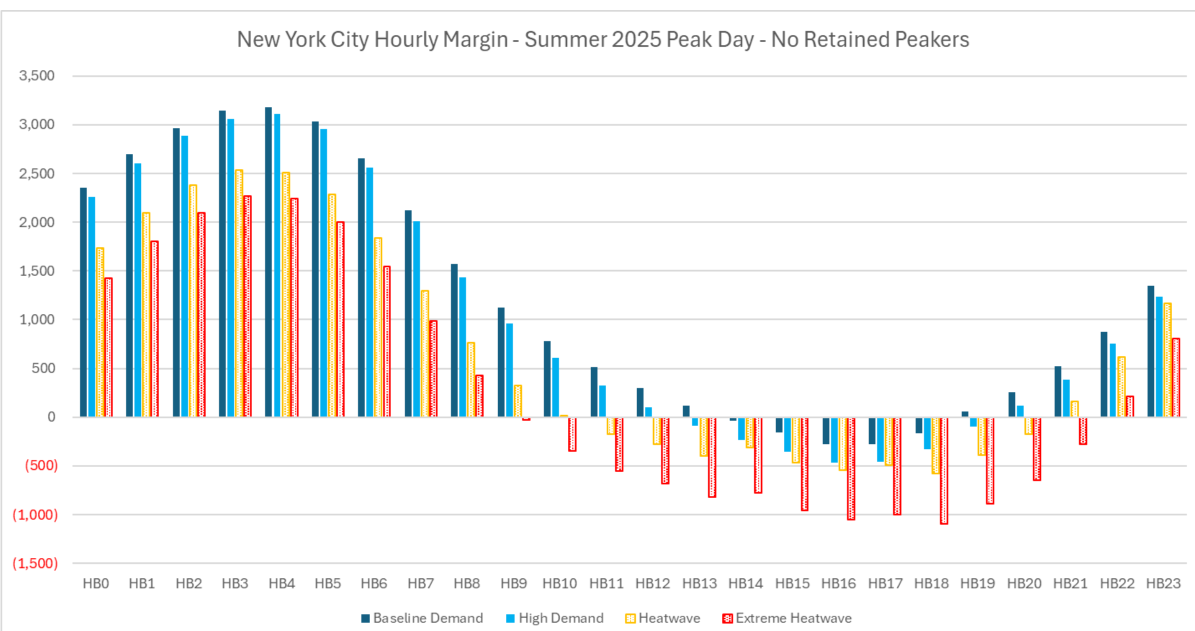


Figure 17: New York City Hourly Transmission Security Margin – Summer Peak



Transmission Security Margin Sensitivities

The NYISO performed sensitivities on the transmission security margins to evaluate the impacts of updated forecasts, and uncertainties in potential system changes or study assumptions. The following factors were evaluated for these sensitivity analyses: updated demand forecast, CHPE unavailability, and the unavailability of Empire Wind 1.

Sensitivity: Forecast Update

The baseline transmission security margins use the demand forecast as published in the 2024 Gold Book, which was available at the start of the 2025 Q2 STAR. This sensitivity evaluates the impact of the demand forecast as published in the 2025 Gold Book after the start date of this STAR. A comparison of the coincident summer peak demand forecast from the 2024 Gold Book and the 2025 Gold Book is shown in Figure 18. The impact to the transmission security margin is shown in Figure 19. The demand forecasts from the 2025 Gold Book will be utilized for the baseline transmission security margins in the 2025 Q3 STAR.

Figure 18: Comparison of Demand Forecasts and MW Impact

Comparison of 2024 Gold Book Forecast and 2025 Gold Book Forecast					
Lower Hudson Valley Locality					
Item	**2025**	**2026**	**2027**	**2028**	**2029**
Zones G-J Baseline Demand Forecast (2024 Gold Book) (MW)	15,066	15,118	15,179	15,244	15,323
Zones G-J Baseline Demand Forecast (2025 Gold Book) (MW)	14,963	15,034	15,103	15,145	15,176
Impact (MW)	*103*	*84*	*76*	*99*	*147*
New York City Locality					
Item	**2025**	**2026**	**2027**	**2028**	**2029**
Zone J Baseline Demand Forecast (2024 Gold Book) (MW)	10,960	10,990	11,020	11,040	11,050
Zone J Baseline Demand Forecast (2025 Gold Book) (MW)	10,764	10,790	10,820	10,840	10,860
Impact (MW)	*196*	*200*	*200*	*200*	*190*
Item	**2025**	**2026**	**2027**	**2028**	**2029**
Zone J High Demand Forecast (2024 Gold Book) (MW)	11,140	11,270	11,400	11,530	11,660
Zone J High Demand Forecast (2025 Gold Book) (MW)	10,800	10,920	11,040	11,170	11,330
Impact (MW)	*340*	*350*	*360*	*360*	*330*
Long Island Locality					
Item	**2025**	**2026**	**2027**	**2028**	**2029**
Zone K Baseline Demand Forecast (2024 Gold Book) (MW)	4,956	4,955	4,968	4,982	5,009
Zone K Baseline Demand Forecast (2025 Gold Book) (MW)	5,003	4,996	5,017	5,038	5,083
Impact (MW)	*(47)*	*(41)*	*(49)*	*(56)*	*(74)*

Figure 19: Transmission Security Margin Sensitivity – Updated Demand Forecasts

Line	Item	2025	2026	2027	2028	2029
Lower Hudson Valley Locality						
A	Zones G-J Baseline Transmission Security Margin	1,408	2,590	2,561	2,542	2,460
B	*Updated Zones G-J Forecast Impact*	*103*	*84*	*76*	*99*	*147*
C	Zones G-J TSM Updated Forecast Sensitivity (A+B)	1,511	2,674	2,637	2,641	2,607
New York City Locality						
A	Zone J Baseline Transmission Security Margin	(281)	489	540	520	510
B	*Updated Zone J Forecast Impact*	*196*	*200*	*200*	*200*	*190*
C	Zone J TSM Updated Forecast Sensitivity (A+B)	(85)	689	740	720	700
D	Zone J High Demand Transmission Security Margin	(461)	209	160	30	(100)
E	*Updated Zone J High Demand Forecast Impact*	*340*	*350*	*360*	*360*	*330*
F	Zone J TSM Updated High Demand Forecast Sensitivity (D+E)	(121)	559	520	390	230
Long Island Locality						
A	Zone K Baseline Transmission Security Margin	411	503	489	474	447
B	*Updated Zone K Forecast Impact*	*(47)*	*(41)*	*(49)*	*(56)*	*(74)*
C	Zone K TSM Updated Forecast Sensitivity (A+B)	364	462	440	418	373

Subsequent sensitivities (below) are shown in reference to the base case baseline transmission security margins and this sensitivity with the updated demand forecasts.

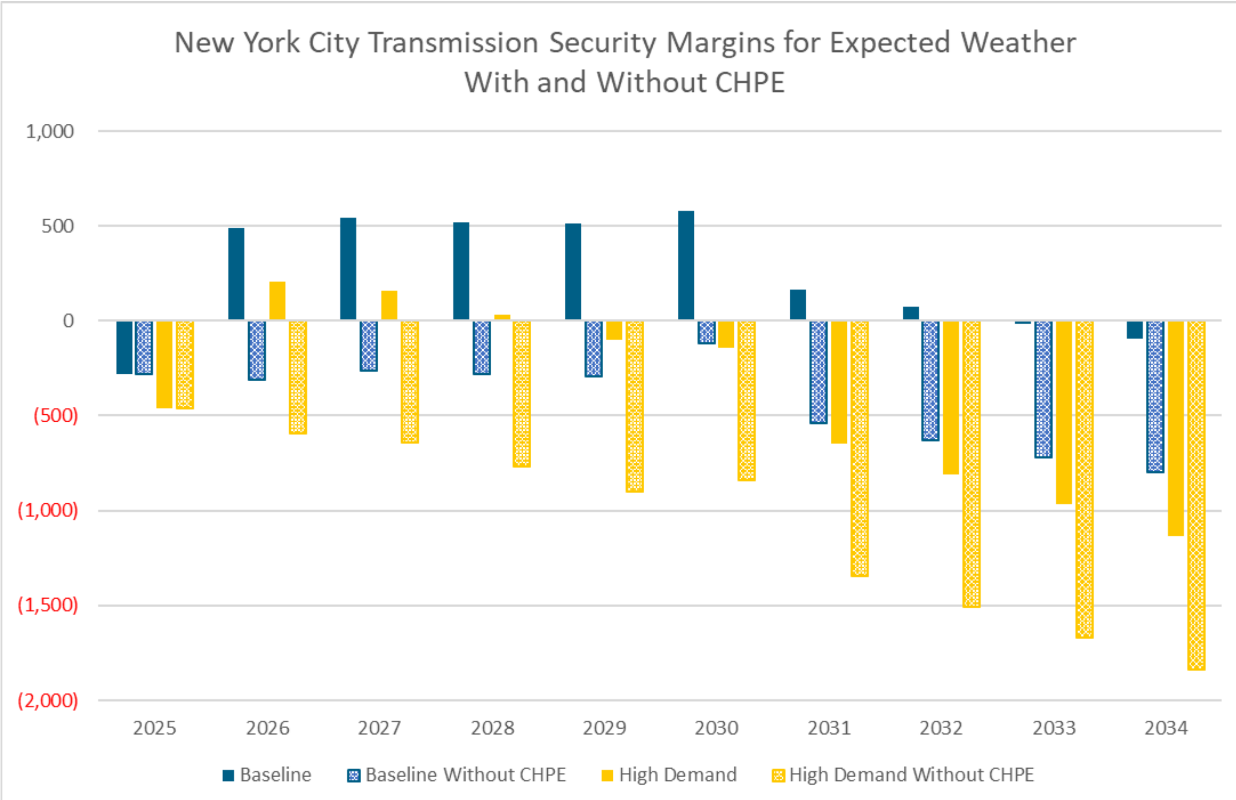
Sensitivity: Zone J for CHPE Unavailability.

Beyond 2025, the reliability margins within New York City will not be sufficient if the CHPE project experiences a significant delay or is otherwise unavailable during summer peak conditions. Figure 20 shows the impact of CHPE's unavailability on the transmission security margin. Specifically, the margin would continue to be deficient for the ten-year planning horizon without the CHPE project in service or other offsetting changes or solutions as shown in Figure 21. In addition, while CHPE is expected to supply capacity in the summer, the facility is not expected to supply capacity from Quebec to New York City under winter peak conditions. CHPE must enter full commercial service and demonstrate that it is capable of being operated to address the reliability needs identified in the 2023 Q2 STAR.

Figure 20: Zone J Transmission Security Margin Sensitivity – CHPE Unavailability

Line	Item	2025	2026	2027	2028	2029
A	Zone J Baseline Transmission Security Margin	(281)	489	540	520	510
B	*CHPE Unavailability Impact*	*0*	*(800)*	*(800)*	*(800)*	*(800)*
C	Zone J TSM CHPE Out Sensitivity (A+B)	(281)	(311)	(260)	(280)	(290)
D	Zone J Baseline TSM with Updated Forecast	(85)	689	740	720	700
E	*CHPE Unavailability Impact*	*0*	*(800)*	*(800)*	*(800)*	*(800)*
F	Zone J TSM with Updated Forecast and CHPE Out Sensitivity (D+E)	(85)	(111)	(60)	(80)	(100)

Figure 21: New York City Transmission Security Margins with and without CHPE



Sensitivity: Zone J for Unavailability of Empire Wind

In April 2025, the Bureau of Ocean Energy Management ordered Empire Wind to cease all construction activities on the Empire Wind 1 project (nameplate 816 MW with commercial operation date of December 2026). Subsequently, the stop work order was lifted in May 2025. This STAR contains a sensitivity that evaluates the impact of the unavailability of this unit to the New York City transmission security margins, which results are included in Figure 22 for information. It is important to note that offshore wind resources are assumed to have a capacity factor of 10% of their nameplate in transmission security margin calculation for summer peak conditions.

Figure 22: New York City Transmission Security Margins with Empire Wind Unavailable

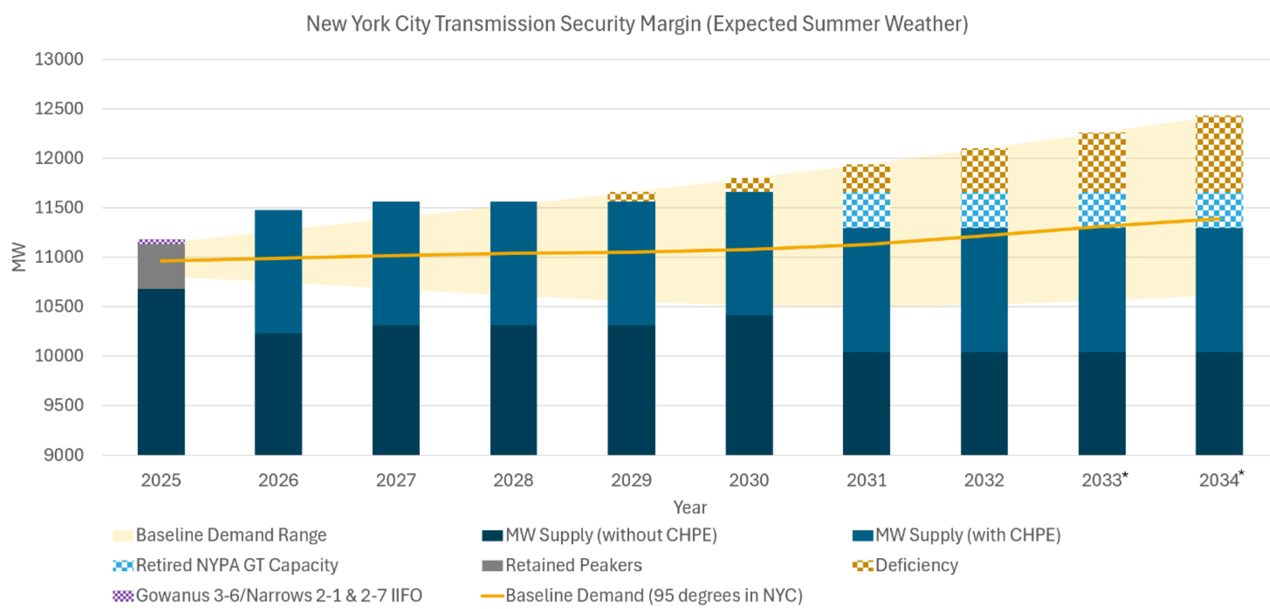
Line	Item	2025	2026	2027	2028	2029
A	**Zone J Baseline Transmission Security Margin**	(281)	489	540	520	510
B	*Empire Wind Unavailable Impact*	*0*	*0*	*(82)*	*(82)*	*(82)*
C	**Zone J TSM Empire Wind Unavailable Sensitivity (A+B)**	(281)	489	459	439	429
D	**Zone J Baseline TSM with Updated Forecast**	(85)	689	740	720	700
E	*Empire Wind Unavailable Impact*	*0*	*0*	*(82)*	*(82)*	*(82)*
F	**Zone J TSM with Updated Forecast Empire Wind Unavailable Sensitivity (D+E)**	(85)	689	659	639	619

Solutions to Previously Identified Short-Term Reliability Needs

On October 3, 2023, the NYISO received proposed solutions to the 2023 Quarter 2 STAR need within New York City. On November 20, 2023 the NYISO issued the Short-Term Reliability Process Report identifying the solution selection to address the 2025 New York City need.[19] The results of this determination were reviewed with stakeholders at the November 29, 2023 Management Committee meeting.[20] There were no viable and sufficient solutions submitted to the NYISO that met the need in 2025. The NYISO determined that temporarily retaining the peaker generators on the Gowanus 2 & 3 and Narrows 1 & 2 barges is necessary to address the need until a permanent solution is in place. The NYISO's designation of the Gowanus 2 & 3 and Narrows 1 & 2 generators will allow their continued operation beyond May 2025 until the earlier of May 1, 2027, or the date a permanent solution is in place and a reliability need does not exist, consistent with the DEC Peaker Rule. The Gowanus and Narrows plant owner, Astoria Generating Company L.P., informed the NYISO that its generators are available to continue operation for so long as they are determined to be needed for reliability and are allowed to continue operating consistent with the Peaker Rule. With the continued operation of these peakers until the earlier of the date (a) the date a permanent solution (*i.e.,* CHPE) is in place and demonstrates dependable capacity supply during summer peak conditions or (b) May 2027, the Need for the currently forecasted demand is addressed if CHPE is not delayed beyond 2026, as shown in the following chart (Figure 23). Without the retention of these generators, the New York City area would not meet the mandatory reliability criteria during expected summer weather peak demand periods.

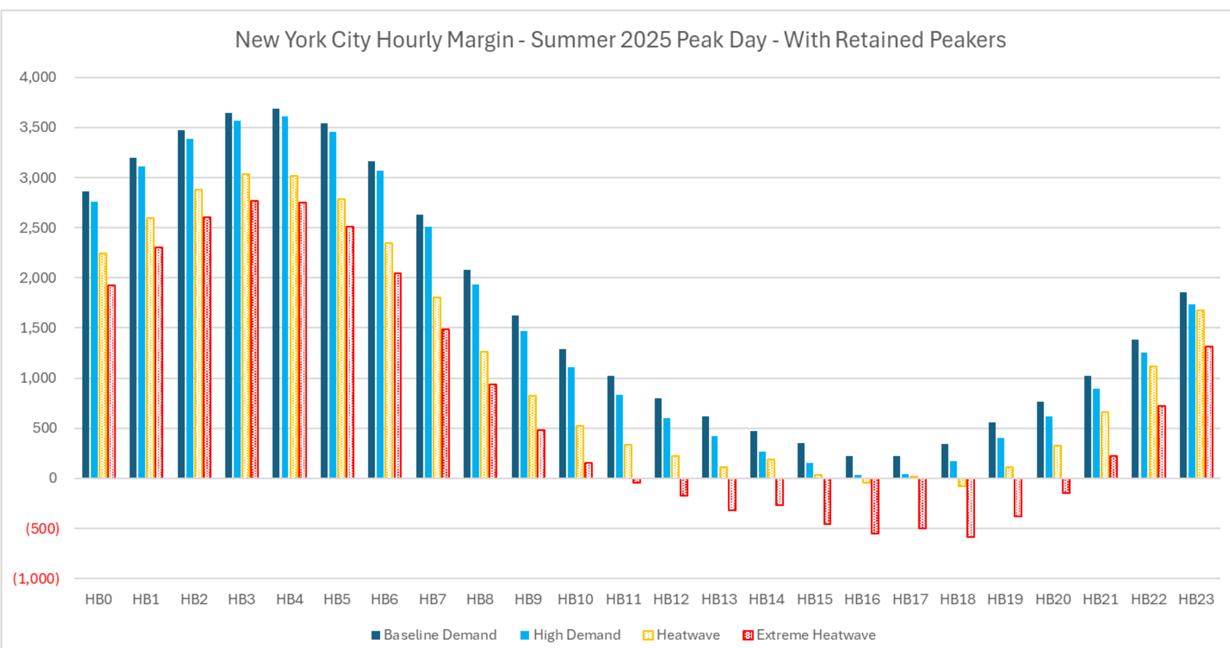
[19] Short-Term Reliability Process Report: 2025 Near-Term Reliability Need, November 20, 2023 (here)
[20] Short-Term Reliability Process Report, Management Committee Meeting, November 29, 2023 (here)

Figure 23: New York City Margin with Designated Peakers



*The 2025 Q2 STAR baseline transmission security margin results are based on the 2024 Gold Book demand forecast. This chart does not use the same assumptions as the 2025-34 Comprehensive Reliabilty Plan as presented by NYISO at the May 6th, 2025 ESPWG/TPAS meeting, which shows no Reliability Need in 2033 and 2034, and that the NYISO determined that a solicitation for solutions is not required to address the Reliability Need identified in the 2024 RNA.The 2025 Q3 STAR baseline transmission security margin results are based on the 2025 Gold Book demand forecast.

Figure 24: New York City Hourly Margin with Designated Peakers



As identified in the NYISO's 2023-2032 Comprehensive Reliability Plan, there are several key risk factors to the relibility of the grid, including generation unavailability and extreme weather. In addition to meeting the identified Near-Term Need and satisfying the mandatory reliability criteria, the retention of the generators on the Gowanus 2 & 3 and Narrows 1 & 2 barges helps to increase

New York City bulk power transmission system resilience during unexpected facility outages or under extreme weather conditions, such as heatwaves (98 degrees Fahrenheit) and extreme heatwaves (102 degrees Fahrenheit) as shown in Figure 24.

The retained generators will participate in the NYISO's economic dispatch, which aligns generation operating schedules with real-time reliability needs. The operating characteristics of the units, primarily their high operating costs relative to other New York City generation and their ability to start quickly and operate with short run-times, will result in the NYISO limiting the run times of the units to the duration of real-time energy needs.

The NYISO's designation of the Gowanus 2 & 3 and Narrows 1 & 2 generators to allow their continued operation beyond May 2025 continues to be necessary to address the reliability need identified in the 2023 Quarter 2 STAR. The barges are sufficient to address the reliability need even with the unavailability of Gowanus 3-6, Narrows 2-1, and Narrows 2-7 as evaluated in this 2025 Q2 STAR.

Local Non-BPTF Reliability Assessment

Generator Deactivation Assessment

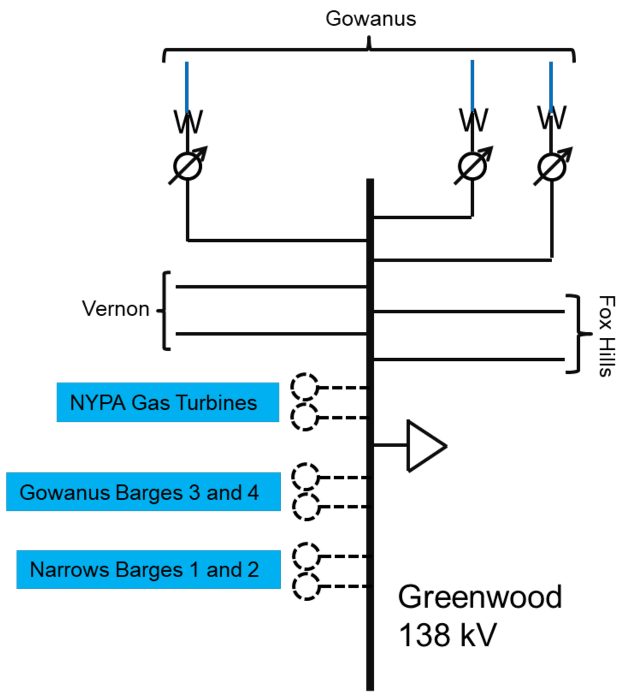
Con Edison performed a deactivation assessment to evaluate the reliability of the local non-BPTF system for the IIFOs of Gowanus 3-6, Narrows 2-1, and Narrows 2-7. Con Edison determined there are no generator deactivation reliability needs on the non-BPTF.

Con Edison previously conducted a local non-BPTF reliability assessment for its non-bulk Greenwood 138 kV transmission load area ("TLA") and observed transmission security violations due to deficiencies. This assessment assumed the Gowanus 2 & 3 and Narrows 1 & 2 barges to be available in summer 2025 due to the overall (Zone J) reliability need as established by the NYISO and unavailable starting in summer 2026. Con Edison's firm[21] solution that it plans to have in-service by summer 2026 is a fourth Gowanus – Greenwood 345/138 kV PAR controlled feeder, which is currently in an engineering / procurement / construction phase(s), with an in-service date of May 2026. The addition of a fourth PAR controlled feeder is an interim solution (i.e., bridge the gap) to be supplemented by future system expansion projects in the local area that are not yet firm projects. Until the fourth Gowanus – Greenwood 345/138 kV PAR controlled feeder is placed into

[21] Con Edison made the fourth Gowanus – Greenwood feeder a firm project on January 21, 2025, ESPWG: https://www.nyiso.com/documents/20142/49295323/CECONY's_LTP_Update_1_21_2025.pdf/abf6cfb4-10e6-eee4-3988-0a434f5a1dcb

service, Con Edison found that the Narrows and Gowanus barges are required to remain in service. If the Greenwood TLA deficiency is not addressed, neighboring TLAs, including the Vernon 138 kV TLA, would also have deficiencies.

Figure 25: Greenwood 138 kV TLA



The unavailability of Gowanus 3-6, Narrows 2-1, and Narrows 2-7 neither results in any identified thermal or voltage violations nor degrades Con Edison's System Restoration Plans. Prior analyses confirmed the absence of fault duty and stability issues under both full unavailability and temporary retention scenarios for the barges.

In summary, the specific deactivations of Gowanus 3-6, Narrows 2-1, and Narrows 2-7 do not pose a reliability concern for the assessed non-BPTF and system restoration capabilities.

Informational Reliability Assessment

Con Edison has indicated potential future reliability issues in the New York City 345/138 kV TLA when considering Con Edison's load forecast, which establishes peak conditions for each TLA. The peak conditions may occur at different times than the NYISO baseline coincident peak forecast. The potential future needs are driven by increasing load and are not a consequence of the three Gowanus and Narrows units entering IIFOs. A more detailed assessment is currently underway by Con Edison as part of its 2025 Local Transmission Owner Plan ("LTP"), which is expected to be finalized by Q4 2025.

Conclusions and Determination

Consistent with the analysis and explanations above, this assessment finds the planned BPTF system through the study period meets applicable reliability criteria, other than the reliability need previously identified in the 2023 Quarter 2 STAR.

The NYISO's designation of the Gowanus 2 & 3 and Narrows 1 & 2 generators to allow their continued operation beyond May 2025 continues to be necessary to address the reliability need identified in the 2023 Quarter 2 STAR. The remaining units on the barges are sufficient to address the reliability need even with the unavailability of Gowanus 3-6, Narrows 2-1, and Narrows 2-7 as included in this 2025 Q2 STAR. Sensitivity analyses to the New York City transmission security margin calculation show that considering updated demand forecasts may mitigate the deficiency identified in the STAR. However, other sensitivities as shown in the 2025 Q1 STAR report show increased reliability risks due to uncertainties pertaining to factors including additional or accelerated generation retirements, or unavailability of power from CHPE. For instance, even with CHPE entering service in summer 2026, the transmission security margin will be narrow and any variation in other assumptions could result in a deficiency. Furthermore, the impact of weather on system performance remains an important reliability risk factor though extreme weather is beyond current design requirements.

In addition to this STAR's findings, Con Edison's local non-BPTF analysis found that the continued operation of the Gowanus and Narrows generators is necessary until the fourth Gowanus – Greenwood 345/138 kV PAR controlled feeder is placed into service. Additionally, Con Edison shared a preliminary assessment for the NYC 345/138 kV TLA that considers peak conditions for each TLA. Con Edison's assessment indicates potential future local needs that are driven by increasing load. Con Edison reported currently performing a more detailed power flow assessment as part of its 2025LTP, which is expected to be finalized by Q4 2025.

No Generator Deactivation Reliability Needs were identified by Con Edison due to the IIFO of Gowanus 3-6, Narrows 2-1, and Narrows 2-7.

Appendix A: List of Short-Term Reliability Needs

The 2023 Quarter 2 STAR found a reliability need beginning in summer 2025 within New York City primarily driven by a combination of forecasted increases in peak demand and the assumed unavailability of certain generation in New York City affected by the "Peaker Rule."[22] Specifically, the 2023 Quarter 2 STAR found that the New York City zone is deficient by as much as 446 MW for a duration of nine hours on the peak day during expected weather conditions when accounting for forecasted economic growth and policy-driven increases in demand. The reliability need is based on a deficient transmission security margin in the New York City locality that accounts for expected generator availability, transmission limitations, and updated demand forecasts using data published in the 2023 Load & Capacity Data Report ("Gold Book").

Appendix B: Short-Term Reliability Process Solution List

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

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

[22] In 2019, the New York State Department of Environmental Conservation adopted a regulation to limit nitrogen oxides (NOx) emissions from simple-cycle combustion turbines, referred to as the "Peaker Rule" (https://www.dec.ny.gov/regulations/116131.html)

Appendix C: Summary of Study Assumptions

This assessment used the major assumptions included in the 2024 RNA, with the key updates noted below. Consistent with the NYISO's obligations under its tariffs, the NYISO provided information to stakeholders on the modeling assumptions employed in this assessment. Details regarding the 2024 RNA study assumptions were reviewed with stakeholders at the April 18, 2024, joint Electric System Planning Working Group ("ESPWG")/Transmission Planning Advisory Subcommittee ("TPAS") meeting. Details regarding the 2025 Q2 STAR study assumptions were reviewed with stakeholders at the May 6, 2025, joint ESPWG/ TPAS meeting. The meeting materials are posted on the NYISO's website.[23] The figures below (Figure 26, Figure 27, Figure 28, and Figure 29) summarize the changes to generation, load, and transmission.

Generation Assumptions

Figure 26: Completed Generator Deactivations

Owner/ Operator	Plant Name	Zone	Nameplate (MW)	CRIS (MW)		Capability (MW)		Status	Deactivation Date (2)	STAR Evaluation (3)
				Summer	Winter	Summer	Winter			
International Paper Company	Ticonderoga (1)	F	9.0	7.6	7.5	9.5	9.8	I	5/1/2017	-
Helix Ravenswood, LLC	Ravenswood 2-4	J	42.9	39.8	50.6	30.7	41.6	I	4/1/2018	-
	Ravenswood 3-1	J	42.9	40.5	51.5	31.9	40.8	I	4/1/2018	-
	Ravenswood 3-2	J	42.9	38.1	48.5	29.4	40.3	I	4/1/2018	-
	Ravenswood 3-4	J	42.9	35.8	45.5	31.2	40.8	I	4/1/2018	-
Rockville Centre, Village of	Charles P Keller 07	K	2.0	2.0	2.0	1.9	1.9	R	3/1/2019	-
Exelon Generation Company LLC	Monroe Livingston	B	2.4	2.4	2.4	2.4	2.4	R	9/1/2019	-
Innovative Energy Systems, Inc.	Steuben County LF	C	3.2	3.2	3.2	3.2	3.2	R	9/1/2019	-
Consolidated Edison Co. of NY, Inc	Hudson Ave 4	J	16.3	13.9	18.2	14.0	16.3	R	9/10/2019	-
New York State Elec. & Gas Corp.	Auburn - State St	C	7.4	5.8	6.2	4.1	7.3	R	10/1/2019	-
Somerset Operating Company, LLC	Somerset	A	655.1	686.5	686.5	676.4	684.4	R	3/12/2020	-
Entergy Nuclear Power Marketing, LLC	Indian Point 2	H	1,299.0	1,026.5	1,026.5	1,011.5	1,029.4	R	4/30/2020	-
Cayuga Operating Company, LLC	Cayuga 1	C	155.3	154.1	154.1	151.0	152.0	R	6/4/2020	-
Entergy Nuclear Power Marketing, LLC	Indian Point 3	H	1,012.0	1,040.4	1,040.4	1,036.3	1,038.3	R	4/30/2021	-
Helix Ravenswood, LLC	Ravenswood GT 11	J	25.0	20.2	25.7	16.1	22.4	I	12/1/2021	2022 Q1
Helix Ravenswood, LLC	Ravenswood GT 1	J	18.6	8.8	11.5	7.7	11.1	I	1/1/2022	2022 Q1
Freeport Electric	Freeport 1-4	K	6.0	4.4	4.4	4.5	5.0	R	5/1/2022	-
Exelon Generation Company LLC	Madison County LF	E	1.6	1.6	1.6	1.6	1.6	I	4/1/2022	2022 Q2
Nassau Energy, LLC	Trigen CC	K	55.0	51.6	60.1	38.5	51.0	R	7/15/2022	2022 Q2
Consolidated Edison Co. of NY, Inc.	Hudson Ave 3	J	16.3	16.0	20.9	12.3	15.6	R	11/1/2022	2022 Q2
Consolidated Edison Co. of NY, Inc.	Hudson Ave 5	J	16.3	15.1	19.7	15.3	18.6	R	11/1/2022	2022 Q2
Astoria Generating Company, L.P.	Gowanus 1-1 through 1-8	J	160.0	138.7	181.1	133.1	182.2	R	11/1/2022	2022 Q2
Astoria Generating Company, L.P.	Gowanus 4-1 through 4-8	J	160.0	140.1	182.9	138.8	183.4	R	11/1/2022	2022 Q2
NRG Power Marketing LLC	Astoria GT 2-1	J	46.5	41.2	50.7	34.9	46.5	R	5/1/2023	2022 Q2
NRG Power Marketing LLC	Astoria GT 2-2	J	46.5	42.4	52.2	34.3	45.6	R	5/1/2023	2022 Q2
NRG Power Marketing LLC	Astoria GT 2-3	J	46.5	41.2	50.7	36.3	46.7	R	5/1/2023	2022 Q2
NRG Power Marketing LLC	Astoria GT 2-4	J	46.5	41.0	50.5	32.5	45.4	R	5/1/2023	2022 Q2
NRG Power Marketing LLC	Astoria GT 3-1	J	46.5	41.2	50.7	34.6	45.0	R	5/1/2023	2022 Q2
NRG Power Marketing LLC	Astoria GT 3-2	J	46.5	43.5	53.5	35.7	45.3	R	5/1/2023	2022 Q2
NRG Power Marketing LLC	Astoria GT 3-3	J	46.5	43.0	52.9	33.9	44.6	R	5/1/2023	2022 Q2
NRG Power Marketing LLC	Astoria GT 3-4	J	46.5	43.0	52.9	34.9	45.5	R	5/1/2023	2022 Q2
NRG Power Marketing LLC	Astoria GT 4-1	J	46.5	42.6	52.4	33.6	43.8	R	5/1/2023	2022 Q2
NRG Power Marketing LLC	Astoria GT 4-2	J	46.5	41.4	51.0	34.3	44.3	R	5/1/2023	2022 Q2
NRG Power Marketing LLC	Astoria GT 4-3	J	46.5	41.1	50.6	35.4	46.4	R	5/1/2023	2022 Q2
NRG Power Marketing LLC	Astoria GT 4-4	J	46.5	42.8	52.7	35.2	44.1	R	5/1/2023	2022 Q2
Helix Ravenswood, LLC	Ravenswood 10	J	25.0	21.2	27.0	16.1	20.3	R	5/1/2023	2022 Q3
Helix Ravenswood, LLC	Ravenswood 01	J	18.6	8.8	11.5	7.7	11.1	R	10/14/2023	2023 Q3
Helix Ravenswood, LLC	Ravenswood 11	J	25.0	20.2	25.7	16.1	22.4	R	10/14/2023	2023 Q3
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	3/1/2024	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
Eastern Generation, LLC	Astoria GT 01	J	16	15.7	20.5	13.8	17.6	R	5/1/2025	2024 Q3
		Total	4,474.0	4,094.3	4,393.5	3,900.5	4,247.3			

Notes
(1) Part of SCR program
(2) This table only includes units that have entered into IIFO or have completed the generator deactivation process.
(3) "-" denotes that the generator deactivation was assessed prior to the creation of the Short-Term Reliability Process

[23] Short-Term Assessment of Reliability: 2025 Q2 Key Study Assumptions, ESPWG/TPAS, May 6, 2025 (here). 2024 RNA Key Study Assumptions, ESPWG/TPAS, April 18, 2024 (here),

Figure 27: Proposed Generator Deactivations

Owner/ Operator	Plant Name (1)	Zone	Nameplate (MW)	CRIS (MW)		Capability (MW)		Status	Deactivation date (2)	STAR Evaluation
				Summer	Winter	Summer	Winter			
Consolidated Edison Co. of NY, Inc.	74 St. GT 1 & 2	J	37	39.1	49.2	0.0	0.0	R	5/1/2023	2022 Q2
Central Hudson Gas & Electric Corp.	Coxsackie GT	G	21.6	21.6	26.0	19.7	22.7	R	12/31/2025 (3)	2024 Q1
National Grid	Shoreham 2	K	18.6	18.5	23.5	17.4	21.5	R	5/1/2025	2025 Q1
Madison Windpower, LLC	Madison Windpower	E	11.6	11.5	11.5	11.6	11.6	R	5/1/2025	2025 Q1
		Total	88.8	90.7	110.2	48.7	55.8			

Notes:

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

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

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

(4) The initial proposed retirement was on or after May 1, 2023, and was studied in the 2022 Q4 STAR. However, the unit modified its Peaker Rule compliance plan to be available for operation through May 1, 2025. The unit has submitted a new generator deactivation notice with a new proposed retirement date by May 1, 2025.

Figure 28: Large Generation Additions

Proposed Project Inclusion: Large Generation					
Queue	**Project Name**	**MW**	**Type**	**Zone**	**Proposed Date**
619	East Point Solar	50	Solar	F	Feb-24
618	High River Solar	90	Solar	F	Jun-24
717	Morris Ridge Solar Energy Center	177	Solar	C	Sep-24
637	Flint Mine Solar	100	Solar	G	Oct-24
766/987	Sunrise Wind II	924	Offshore Wind	K	Mar-26
737	Empire Wind 1	816	Offshore Wind	J	Dec-26

Figure 29: Small Generation Additions

Proposed Project Inclusion: Small Generation					
	Name	MW	Type	Zone	Proposed Date
572	Greene County 1	20	Solar	G	Jan-23
573	Greene County 2	10	Solar	G	Mar-23
545	Sky High Solar	20	Solar	C	Jun-23
744	Magruder BESS	20	Energy Storage	G	Sep-23
581	Hills Solar	20	Solar	E	Feb-24
586	Watkins Rd Solar	20	Solar	E	Feb-24
584	Dog Corners Solar	20	Solar	C	Apr-24
833	Dolan Solar	20	Solar	F	Apr-24
565	Tayandenega Solar	20	Solar	F	Jun-24
1003	Clear View Solar	20	Solar	C	Jun-24
564	Rock District Solar	20	Solar	F	Jul-24
807	Hilltop Solar	20	Solar	F	Jul-24
670	SunEast Skyline Solar LLC	20	Solar	E	Aug-24
734	Ticonderoga Solar	20	Solar	F	Aug-24
832	CS Hawthorn Solar	20	Solar	F	Aug-24
804	KCE NY 10*	20	Energy Storage	A	Nov-24
828	Valley Solar	20	Solar	C	Nov-24
590	Scipio Solar	18	Solar	C	Dec-24
591	Highview Solar	20	Solar	C	Dec-24
575	Little Pond Solar	20	Solar	G	Jan-25
848	Fairway Solar	20	Solar	E	Mar-25
592	Niagara Solar	20	Solar	B	Jun-25
855	NY13 Solar	20	Solar	F	Jun-25
865	Flat Hill Solar	20	Solar	E	Dec-25
885	Grassy Knoll Solar	20	Solar	E	Dec-25

Notes:
*Project does not have CRIS.

Demand Assumptions

The 2025 Quarter 2 STAR uses the baseline coincident peak demand forecasts for the study years consistent with the 2024 Gold Book.

Transmission Assumptions

The study assumptions for existing transmission facilities that are modeled as out-of-service are listed in Figure 30. Figure 31 shows the Con Edison series reactor status utilized in the 2024 RNA as well as for this STAR. There are no changes to the Con Edison series reactor assumptions in this STAR compared to the 2024 RNA. Figure 32 and Figure 33 provide a summary of the transmission projects included in the 2024 RNA Base Cases as listed in the 2024 Gold Book.

Figure 30: 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	3/2025	9/2025
Stolle Rd	Stolle Rd	115	T11-52	6/2025	
Station 23	Station 42	115	920	12/2025	
Farragut		345	8E	-	11/2025
Farragut		345	9E	-	11/2025

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

Figure 31: Con Edison Proposed Series Reactor Status

Terminals		ID	kV	Prior to Summer 2023	Starting Summer 2023
Dunwoodie	Mott Haven	71	345	By-Passed	In-Service
Dunwoodie	Mott Haven	72	345	By-Passed	In-Service
Sprainbrook	W. 49th Street	M51	345	By-Passed	In-Service
Sprainbrook	W. 49th Street	M52	345	By-Passed	In-Service
Farragut	Gowanus	41	345	In-Service	By-Passed
Farragut	Gowanus	42	345	In-Service	By-Passed
Sprainbrook	East Garden City	Y49	345	In-Service	By-Passed

The change in the planned status of the specified series reactors is only implemented for the summer.

Figure 32: Major Transmission Projects Included in 2024 RNA Base Cases

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	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

Figure 33: Transmission Project Inclusion Rules Application for 2024 RNA Base Case

Transmission Project Includion Rules Application: Class Year Transmission, TIP, and Firm LTP Projects Not Included in the RNA Base Cases											
Transmission Owner	Terminals		Line Length (Miles)	Proposed In-Service Date		Nominal Voltage (kV)		# of CKTs	Thermal Ratings (4)		Project Description / Conductor Size
				Prior to (2)	Year	Operating	Design		Summer	Winter	
Clean Path New York LLC	Fraser 345kV	Rainey 345kV	173	S	2027	492	492	1	1300 MW	1300 MW	'-/+ 400kV Bipolar HVDC cable
NYSEG	Canandaigua	Stoney Ridge	24	W	2030	230	230	1	795 MVA	853 MVA	Rebuild the existing 24 mile 230 kV line #68 with mile 230 kV line with bundled 1192 Bunting ACSR ACSR conductor.
NYSEG	Hillside	Watercure	1	W	2030	230	230	1	819 MVA	972 MVA	Rebuild the existing 1 mile 230 kV line #69 with 2156 Bluebird ACSR conductor.
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
NYSEG	Stolle Rd	High Sheldon	11	W	2030	230	230	1	795 MVA	853 MVA	Rebuild the existing 11-mile 230 kV line #67 with bundled 1192 Bunting ACSR conductor on an offset with steel monopole structures.
NYSEG	Stoney Ridge	Hillside	27	W	2030	230	230	1	795 MVA	886 MVA	Rebuild the existing 27 mile 230 kV line #72 with 2156 Bluebird ACSR conductor.

Appendix D: Resource Adequacy Assumptions

2025 Q2 STAR MARS Assumptions Matrix

	Parameter	2024 RNA Base Cases Key Assumptions (2024 Gold Book)	2025 Q1, Q2 STAR 2024 Q3, Q4 STAR Key Assumptions (2024 GB plus ESPWG key updates)
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 GB 2024 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 will be used for the 2024 RNA, as provided by the Demand Forecasting Team which then allows for a discrete modeling of the BtM solar resources using 5 years of inverter data.	Same method
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.	Same method
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).	Same
3	Load Forecast Uncertainty (LFU) The LFU model captures the impacts of weather conditions on future loads.	2024 LFU Updated via Load Forecast Task Force process. 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])* **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.	Same

	Parameter	2024 RNA Base Cases Key Assumptions (2024 Gold Book)	2025 Q1, Q2 STAR 2024 Q3, Q4 STAR Key Assumptions (2024 GB plus ESPWG key updates)
		Additional details are available in the April 18 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	Same method
2	**Proposed New Units Inclusion** Determination	2024 Gold Book with RNA Base Case inclusion rules applied	Same method
3	Retirement, Mothballed Units, IIFO	2024 Gold Book with RNA Base Case inclusion rules applied	Same method
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.	Same method
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.	Same method
6	Daily Maintenance	Fixed maintenance based on schedules received by the NYISO.	Same method
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 system to determine the number of weeks on maintenance for each thermal unit.	Same method
8	Summer Maintenance	None	Same
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.	Same method
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.	Same method

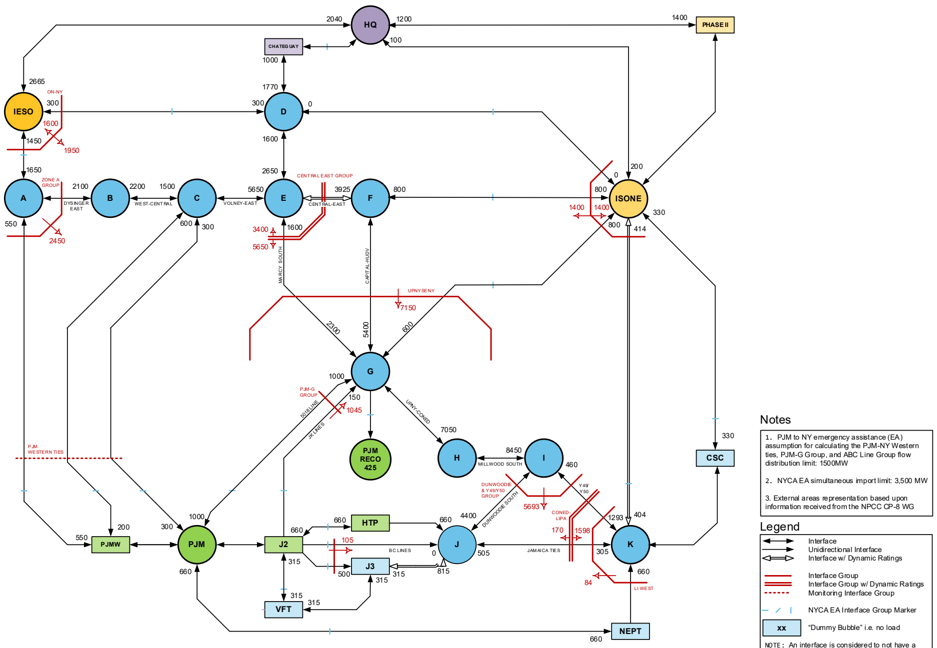
	Parameter	2024 RNA Base Cases Key Assumptions (2024 Gold Book)	2025 Q1, Q2 STAR 2024 Q3, Q4 STAR Key Assumptions (2024 GB plus ESPWG key updates)
		Probabilistic model is incorporated based on five years of input shapes, with one shape per replication randomly selected in the Monte Carlo process.	
11	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.	Same method
12	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)	Same method
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.	Same method
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 for the 2024 RNA, as developed by the NYISO forecasting team.	Same method
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.	Same method
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.	Same method
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.	Same method
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.	Same method
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.	Same method
Transaction – Imports/ Exports			

	Parameter	2024 RNA Base Cases Key Assumptions (2024 Gold Book)	2025 Q1, Q2 STAR 2024 Q3, Q4 STAR Key Assumptions (2024 GB plus ESPWG key updates)
1	Capacity Purchases	Grandfathered Rights and other awarded long-term rights Modeled using MARS explicit contracts feature.	Same method
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	Same method
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	Same method
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.	Same method
5	External Deliverability Rights (EDRs)	**Cedars Uprate 80 MW**. Modeled reflecting External CRIS rights.	Same method
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.	Same method
MARS Topology: a simplified bubble-and-pipe representation of the transmission system			
1	Interface Limits	Developed by review of previous studies and specific analysis during the RNA study process.	Same method
2	New Transmission	Based on TO-provided firm plans (via Gold Book/LTP 2023-2024 processes) and proposed merchant transmission facilities meeting the RNA Base Case inclusion rules.	Same method
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.	Same method
4	UDR unavailability	Five-year history of forced outages.	Same method
Emergency Operating Procedures (EOPs)			
1	EOP Steps Order	**New order:** Implementing NYSRC ICS/EC November 9, 2023 decision for the new EOP order recommendation: 1. Removing Operating Reserve 2. Special Case Resources (SCRs) (Load and Generator) 3. 5% Manual Voltage Reduction 4. 30-Minute Operating Reserve to Zero 5. Voluntary Load Curtailment 6. Public Appeals 7. 5% Remote Controlled Voltage Reduction 8. Emergency Assistance from External Areas	Same method

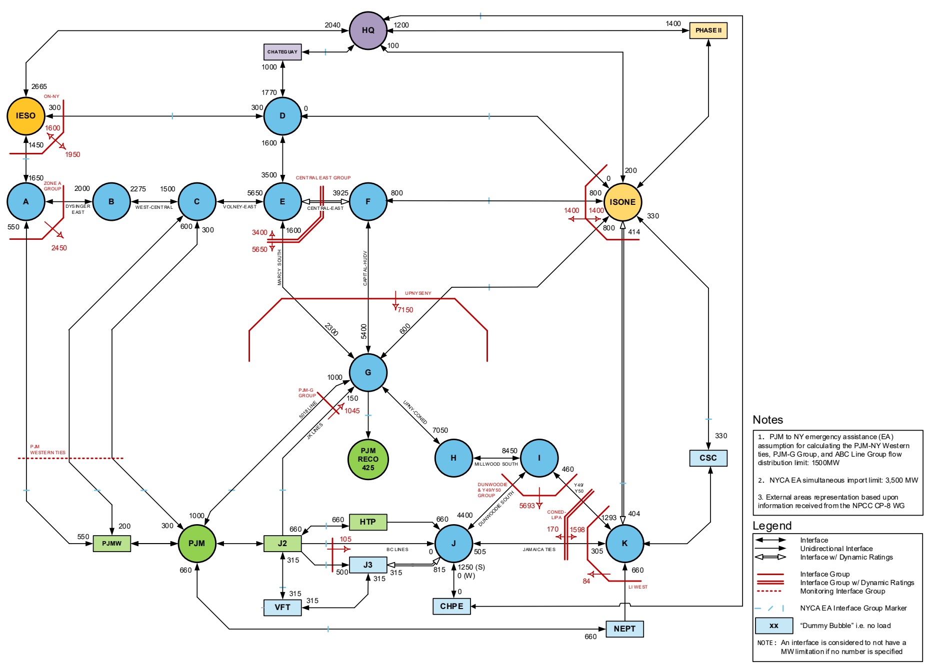
	Parameter	2024 RNA Base Cases Key Assumptions (2024 Gold Book)	2025 Q1, Q2 STAR 2024 Q3, Q4 STAR Key Assumptions (2024 GB plus ESPWG key updates)
		9. Part of the 10-Minute Operating Reserve (910 MW of 1310 MW) to Zero	
2	Special Case Resources (SCR)	SCRs sold for the program discounted to historic availability (“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].	Same method
3	EDRP Resources	Not modeled if the values are less than 2 MW.	Same
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).	Same
5	Other EOPs *(e.g., manual voltage reduction, voltage curtailments, public appeals, external assistance, as listed above)*	Based on TO information, measured data, and NYISO forecasts. Will use 2024 elections, as available.	Same method
1	PJM	Simplified model: The 5 PJM MARS areas (bubbles) were consolidated into one starting 2020 RNA. As per RNA procedure.	Same method
2	ISONE	Simplified model: The 8 ISO-NE MARS areas (bubbles) were consolidated into one starting 2020 RNA	Same method
3	HQ	Per RNA Procedure.	Same method
4	IESO	Per RNA procedure.	Same method

	Parameter	2024 RNA Base Cases Key Assumptions (2024 Gold Book)	2025 Q1, Q2 STAR 2024 Q3, Q4 STAR Key Assumptions (2024 GB plus ESPWG key updates)
5	Reserve Sharing	All NPCC Control Areas indicate that they will share reserves equally among all members before sharing with PJM.	Same method
6	NYCA Emergency Assistance Limit	Implemented a statewide limit of 3,500 MW, additional to the “pipe” limits.	Same method
Miscellaneous			
1	MARS Model Version	4.14.2179	Same

2024 RNA MARS Topology[24]



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)

24 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 2024 Gold Book and the projects that meet the reliability planning inclusion rules for the 2025 Q2 STAR. At the May 5, 2022[25] and May 23, 2022[26] joint meetings of the Transmission Planning Advisory Subcommittee ("TPAS") and the Electric System Planning Working Group ("ESPWG"), the NYISO discussed with stakeholders several enhancements to its reliability planning practices. The proposed changes to reliability planning practices include: (1) modeling intermittent resources according to their expected availability coincident with the represented system condition, (2) accounting for the availability of thermal generation based on NERC class average five-year outage rate data in transmission security assessments, and (3) incorporating the ability to identify reliability needs through the spreadsheet-based method of calculating transmission security margins (a.k.a. "tipping points") within the Lower Hudson Valley (Zones G-J), New York City (Zone J), and Long Island (Zone K) localities, as well as other enhancements to reliability planning practices. At its June 23, 2022, meeting, the Operating Committee approved revisions to the Reliability Planning Process Manual that reflect these enhancements. For this assessment, the margins are evaluated statewide as well as Lower Hudson Valley, New York City, and Long Island localities.

A BPTF reliability need is identified when the transmission security margin under expected weather conditions in the Lower Hudson Valley, New York City, and Long Island localities are less than zero. Additional details regarding the statewide system margin, impact of extreme weather, or other scenario conditions are provided to more fully understand the uncertainties 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 6,350 MW of gas generation throughout the NYCA.

[25] https://www.nyiso.com/documents/20142/30451285/08_Reliability_Practices_TPAS-ESPWG_2022-05-05.pdf/.
[26] https://www.nyiso.com/documents/20142/30860639/04%20Response%20to%20SHQuestions%20and%20Feedback%20on%202022%20RNA%202022%20Quarter%202%20STAR.pdf/.

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

Statewide System Margin

The statewide system margin for New York is evaluated under baseline 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 base case 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.

As shown in Figure 34, under summer peak baseline expected weather load, normal transfer criteria, the statewide system margin (line-item I) ranges between 1,064 MW in 2025 to -12 MW in 2034 with flexible large loads modeled as offline. When flexible large loads are modeled online during the summer peak day, the statewide system margin (line-item I) ranges between 453 MW in 2025 to –1,192 MW in 2034 as shown in Figure 35. Figure 36 shows the statewide system margin for summer with and without the flexible large loads online for comparison. Figure 37 shows the summer peak statewide system margin through the study horizon for baseline load and the impacts of the higher demand load forecast, special case resources ("SCRs"), and with full operating reserve with flexible large loads offline. Figure 38 shows the summer peak statewide system margin through the study horizon for baseline load and the impacts of the higher demand load forecast, SCRs, and with full operating reserve and with flexible large loads modeled as online. Figure 39 shows the hourly statewide system margin for the summer peak day for 2025, 2029, and 2034 with flexible large loads online. The addition of Q1213 - St Lawrence Data and Agricultural Center (Zone D), as modeled in the 2025 Q1 STAR and this 2025 Q2 STAR, further reduces the statewide

[27] NERC five-year class average EFORd data

system margin by 200 MW by 2027.

As shown in Figure 40, under winter peak baseline expected weather load, normal transfer criteria, the statewide system margin (line-item J) ranges between 4,221 MW in 2025 to -2,283 MW in 2034 with flexible large loads modeled as offline. When flexible large loads are modeled as online during the winter peak day, the statewide system margin (line-item J) ranges between 3,459 MW in 2025 to –3463 in 2034 as shown in Figure 41. Figure 42 shows the statewide system margin for winter with and without the flexible large loads online for comparison. Figure 43 shows the winter peak statewide system margin through the study horizon for baseline load and the impacts of, SCRs, with full operating reserve and with flexible large loads modeled as offline. Figure 44 shows the winter peak statewide system margin through the study horizon for baseline load and the impacts of SCRs, and with full operating reserve and with flexible large loads modeled as online. The addition of Q1213- St Lawrence Data and Agricultural Center (Zone D) as modeled in the 2025 Q1 STAR and this 2025 Q2 STAR, further reduces the statewide system margin by 200 MW by 2027.

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 that the system is unable to securely meet system load under applicable normal transfer criteria, which is observed in the RNA transmission security results as described previously in this appendix.

Figure 34: Summer Peak Statewide System Margin Calculation (Flexible Large Loads Offline)

Line	Item	Summer Peak - Baseline Expected Summer Weather, Normal Transfer Criteria (MW)									
		2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
A	NYCA Generation (1)	38,045	39,069	39,885	39,885	39,885	39,885	39,429	39,429	39,429	39,429
B	NYCA Generation Derates (2)	(6,476)	(7,419)	(8,165)	(8,187)	(8,198)	(8,210)	(8,173)	(8,184)	(8,195)	(8,195)
C	Temperature Based Generation Derates	0	0	0	0	0	0	0	0	0	0
D	External Area Interchanges (3)	1,844	3,094	3,094	3,094	3,094	3,094	3,094	3,094	3,094	3,094
E	**Total Resources (A+B+C+D)**	33,413	34,743	34,814	34,791	34,780	34,769	34,351	34,339	34,328	34,328
F	Demand Forecast (5)	(31,039)	(30,902)	(30,930)	(30,950)	(31,160)	(31,400)	(31,700)	(32,140)	(32,650)	(33,030)
G	Largest Loss-of-Source Contingency	(1,310)	(1,310)	(1,310)	(1,310)	(1,310)	(1,310)	(1,310)	(1,310)	(1,310)	(1,310)
H	**Total Capability Requirement (F+G)**	(32,349)	(32,212)	(32,240)	(32,260)	(32,470)	(32,710)	(33,010)	(33,450)	(33,960)	(34,340)
I	**Statewide System Margin (E+H)**	1,064	2,531	2,574	2,531	2,310	2,059	1,341	889	368	(12)
J	Higher Demand Impact	(550)	(1,010)	(1,340)	(1,810)	(2,060)	(2,330)	(2,600)	(2,810)	(2,980)	(3,270)
K	**Higher Demand Statewide System Margin (I+J)**	514	1,521	1,234	721	250	(271)	(1,259)	(1,921)	(2,612)	(3,282)
L	SCRs (6), (7)	989	989	989	989	989	989	989	989	989	989
M	**Statewide System Margin with SCR (K+L)**	1,503	2,511	2,223	1,711	1,239	718	(270)	(931)	(1,623)	(2,293)
N	Operating Reserve	(1,310)	(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)**	193	1,201	913	401	(71)	(592)	(1,580)	(2,241)	(2,933)	(3,603)

Notes:

1. Reflects the 2024 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 (2024 Gold Book Table I-9a) and solar PV peak reductions (2024 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
3. Interchanges are based on ERAG MMWG values.
4. For informational purposes.
5. Reflects the 2024 Gold Book Forecast with flexible large loads considered offline.
6. SCRs are not applied for transmission security analysis of normal operations, but are included for emergency operations.
7. Includes a derate of 384 MW for SCRs

Figure 35: Summer Peak Statewide System Margin Calculation (Flexible Large Loads Online)

Line	Item	Summer Peak - Baseline Expected Summer Weather, Normal Transfer Criteria (MW)									
		2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
A	NYCA Generation (1)	38,045	39,069	39,885	39,885	39,885	39,885	39,429	39,429	39,429	39,429
B	NYCA Generation Derates (2)	(6,476)	(7,419)	(8,165)	(8,187)	(8,198)	(8,210)	(8,173)	(8,184)	(8,195)	(8,195)
C	Temperature Based Generation Derates	0	0	0	0	0	0	0	0	0	0
D	External Area Interchanges (3)	1,844	3,094	3,094	3,094	3,094	3,094	3,094	3,094	3,094	3,094
E	**Total Resources (A+B+C+D)**	33,413	34,743	34,814	34,791	34,780	34,769	34,351	34,339	34,328	34,328
F	Demand Forecast (5)	(31,650)	(31,900)	(32,110)	(32,130)	(32,340)	(32,580)	(32,880)	(33,320)	(33,830)	(34,210)
G	Largest Loss-of-Source Contingency	(1,310)	(1,310)	(1,310)	(1,310)	(1,310)	(1,310)	(1,310)	(1,310)	(1,310)	(1,310)
H	**Total Capability Requirement (F+G)**	(32,960)	(33,210)	(33,420)	(33,440)	(33,650)	(33,890)	(34,190)	(34,630)	(35,140)	(35,520)
I	**Statewide System Margin (E+H)**	453	1,533	1,394	1,351	1,130	879	161	(291)	(812)	(1,192)
J	Higher Demand Impact	(550)	(1,010)	(1,340)	(1,810)	(2,060)	(2,330)	(2,600)	(2,810)	(2,980)	(3,270)
K	**Higher Demand Statewide System Margin (I+J)**	(97)	523	54	(459)	(930)	(1,451)	(2,439)	(3,101)	(3,792)	(4,462)
L	SCRs (6), (7)	989	989	989	989	989	989	989	989	989	989
M	**Statewide System Margin with SCR (K+L)**	892	1,513	1,043	531	59	(462)	(1,450)	(2,111)	(2,803)	(3,473)
N	Operating Reserve	(1,310)	(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)**	(418)	203	(267)	(779)	(1,251)	(1,772)	(2,760)	(3,421)	(4,113)	(4,783)

Notes:

1. Reflects the 2024 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 (2024 Gold Book Table I-9a) and solar PV peak reductions (2024 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 August 2023 (https://www.nerc.com/pa/RAPA/gads/Pages/Reports.aspx).
3. Interchanges are based on ERAG MMWG values.
4. For informational purposes.
5. Reflects the 2024 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 384 MW for SCRs

Figure 36: Summer Peak Statewide System Margin – Flexible Large Loads Comparison

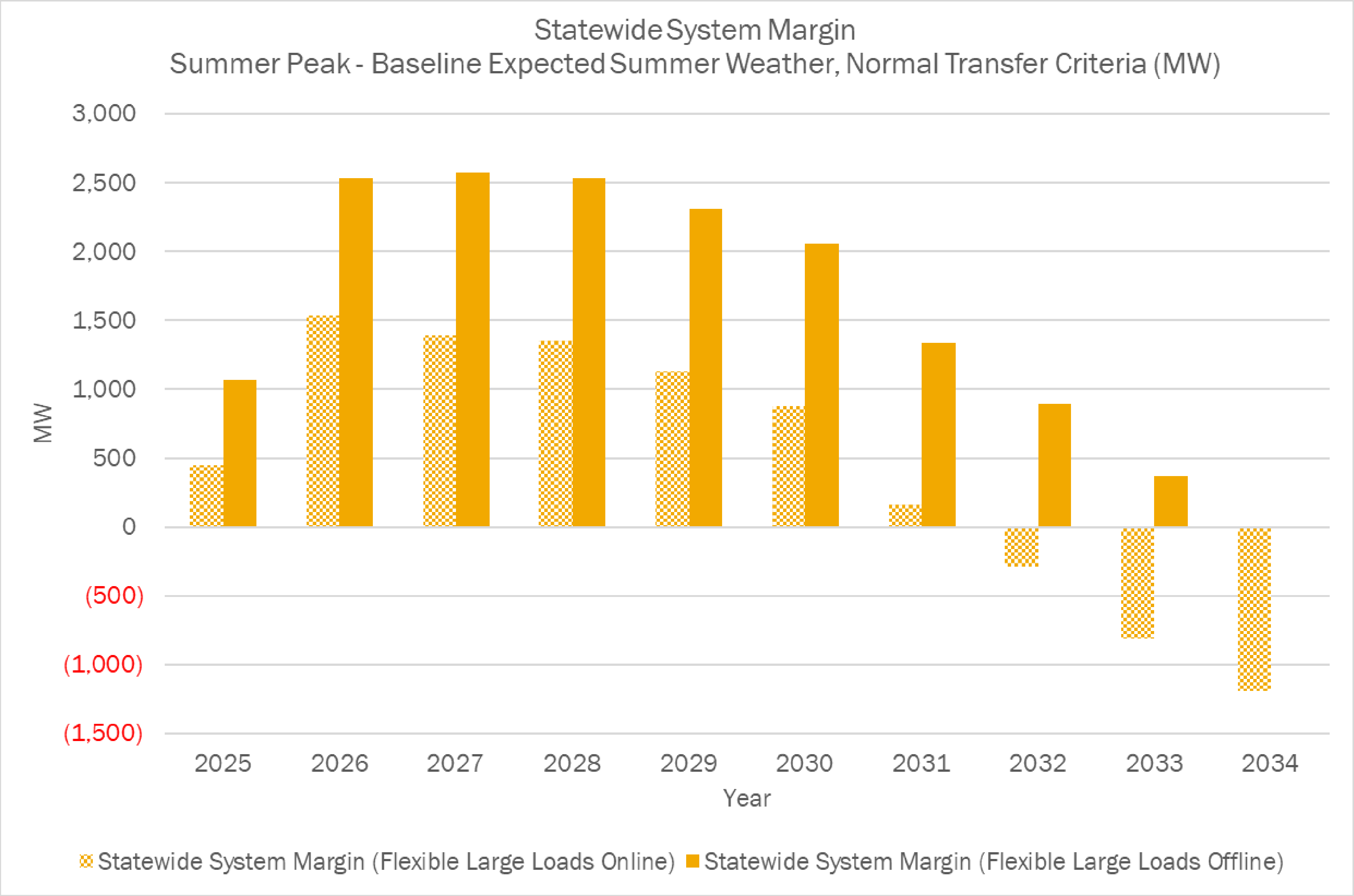


Figure 37: Summer Peak Statewide System Margin Chart (Flexible Large Loads Offline)

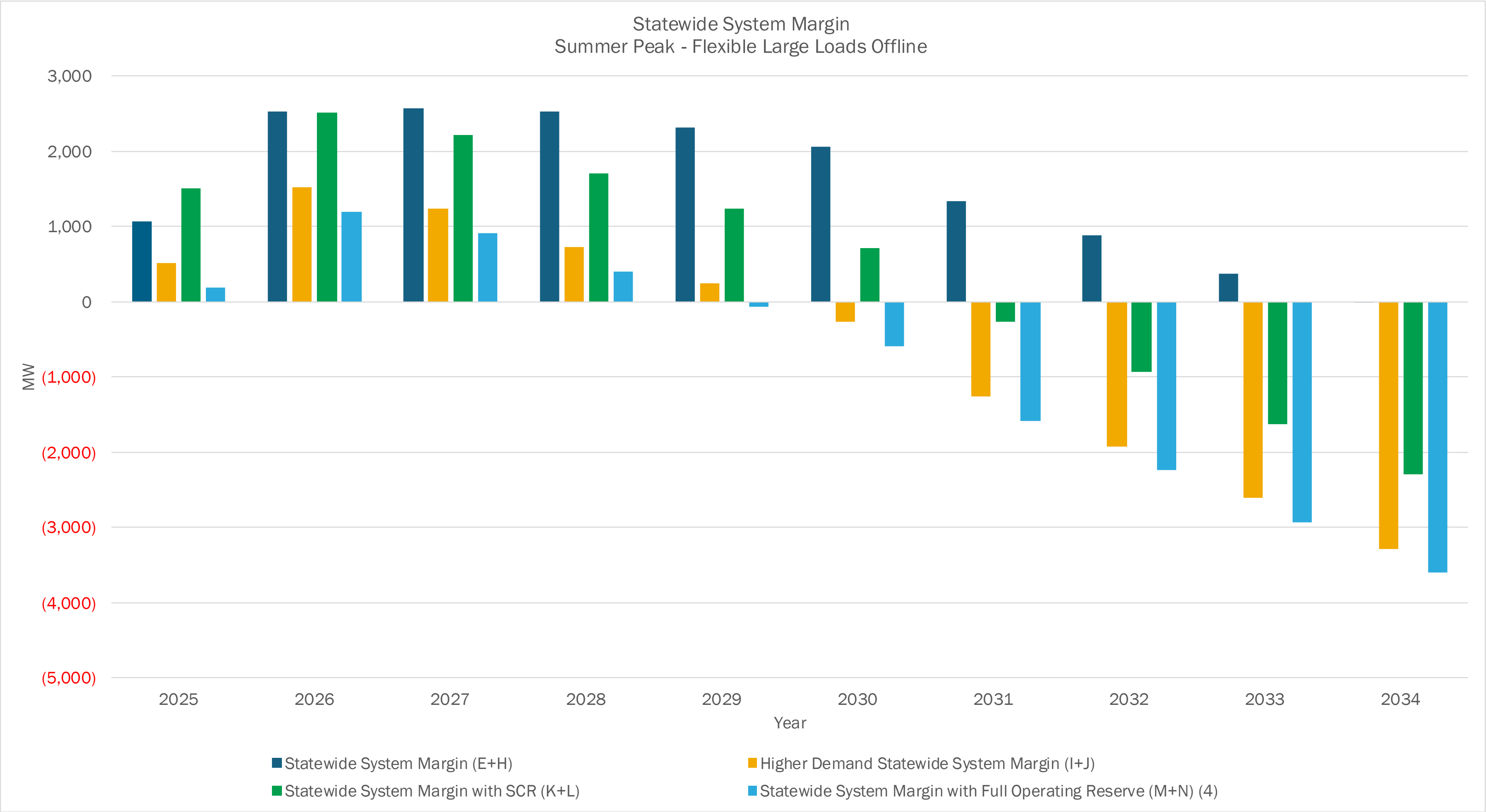


Figure 38: Summer Peak Statewide System Margin Chart (Flexible Large Loads Online)

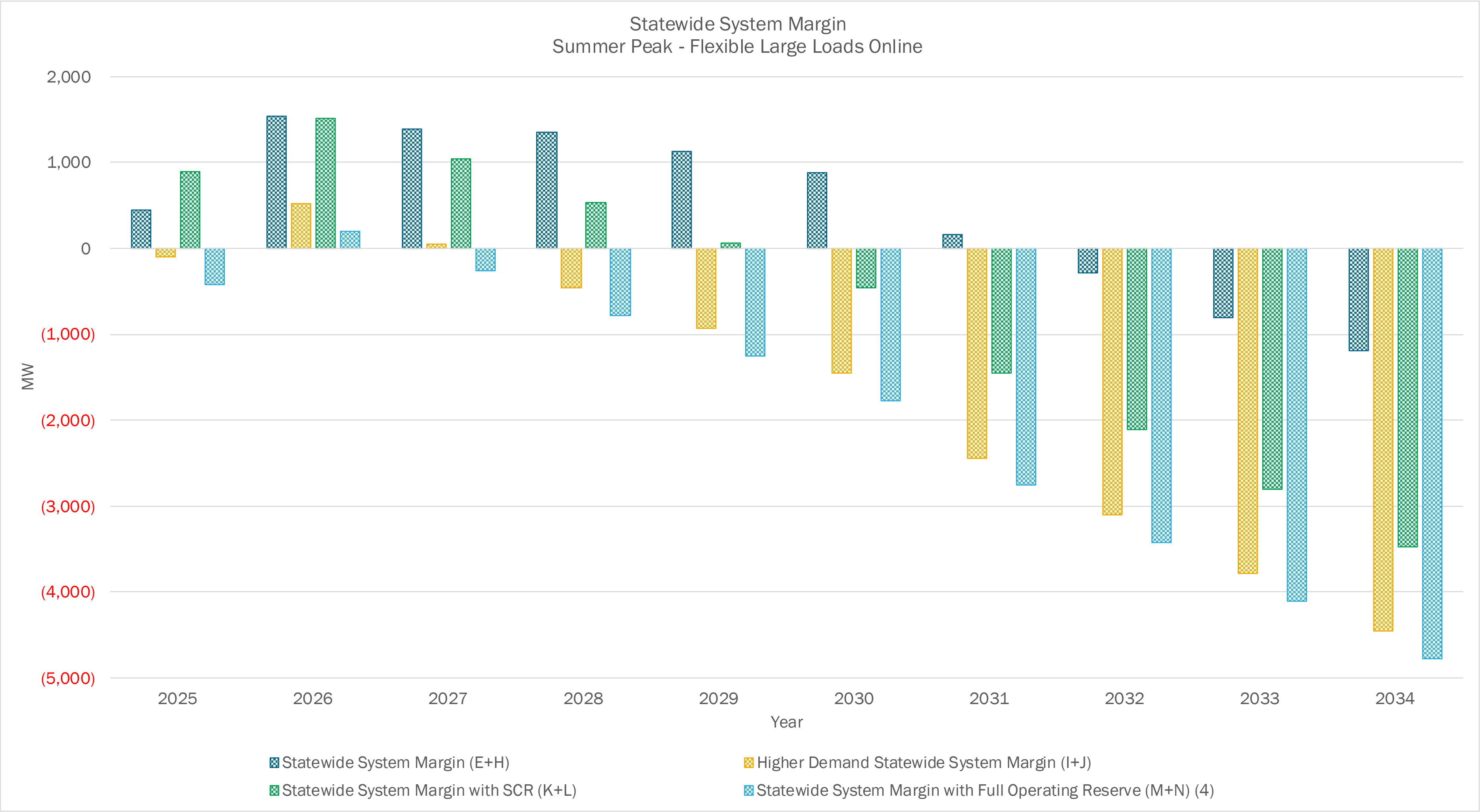


Figure 39: Summer Peak Statewide System Hourly Margin Chart

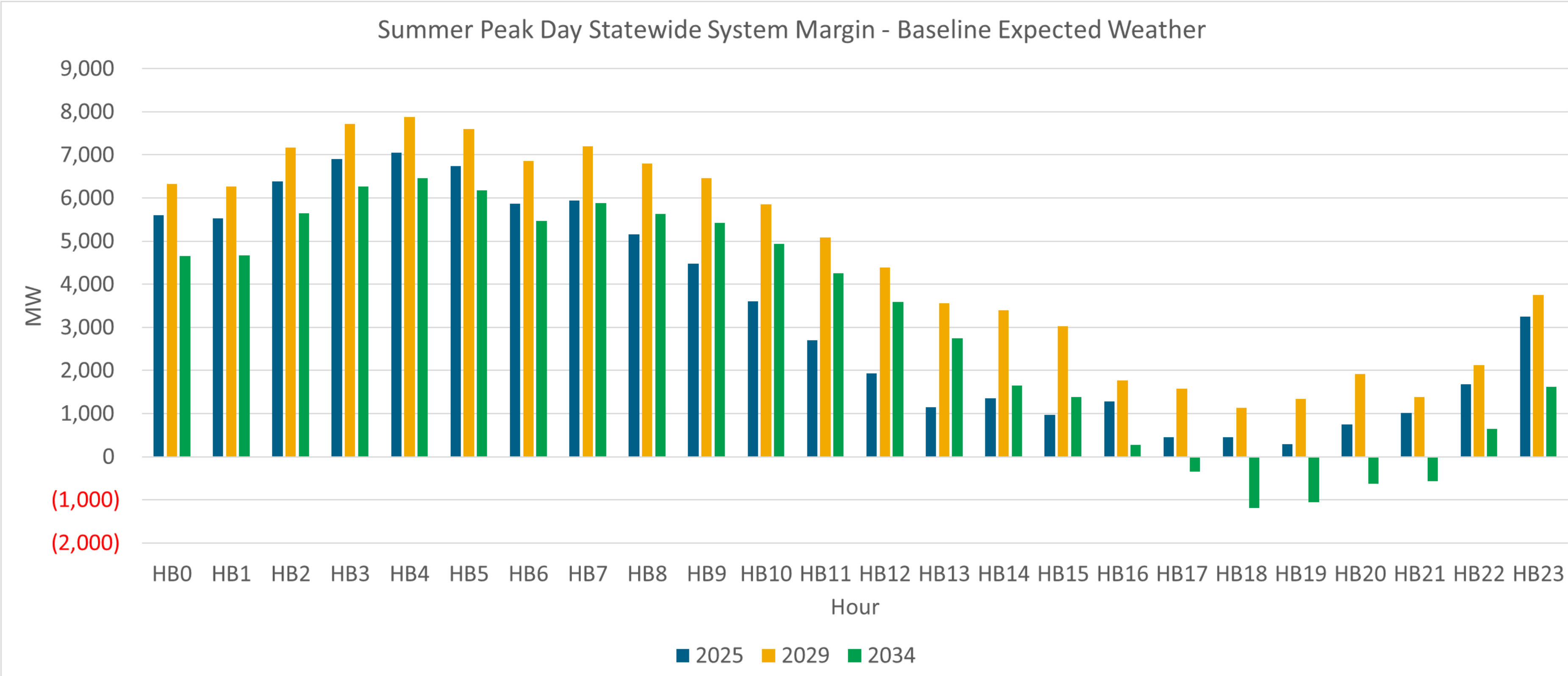


Figure 40: Winter Peak Statewide System Margin Calculation (Flexible Large Loads Offline)

Line	Item	Winter Peak - Baseline Expected Winter Weather, Normal Transfer Criteria (MW)									
		2025-26	2026-27	2027-28	2028-29	2029-30	2030-31	2031-32	2032-33	2033-34	2034-35
A	NYCA Generation (1)	40,980	42,720	42,720	42,720	42,720	42,262	42,262	42,262	42,262	42,262
B	NYCA Generation Derates (2)	(6,417)	(7,809)	(7,809)	(7,809)	(7,809)	(7,809)	(7,809)	(7,809)	(7,809)	(7,809)
C	Unavailability of Non-Firm Gas (6)	(6,319)	(6,319)	(6,319)	(6,319)	(6,319)	(5,861)	(5,861)	(5,861)	(5,861)	(5,861)
D	Temperature Based Generation Derates	0	0	0	0	0	0	0	0	0	0
E	External Area Interchanges (3)	735	735	735	735	735	735	735	735	735	735
F	**Total Resources (A+B+C+D+E)**	28,979	29,327	29,327	29,327	29,327	29,327	29,327	29,327	29,327	29,327
G	Demand Forecast (5)	(23,448)	(23,622)	(24,090)	(24,580)	(25,170)	(25,840)	(26,720)	(27,670)	(28,770)	(30,300)
H	Largest Loss-of-Source Contingency	(1,310)	(1,310)	(1,310)	(1,310)	(1,310)	(1,310)	(1,310)	(1,310)	(1,310)	(1,310)
I	**Total Capability Requirement (G+H)**	(24,758)	(24,932)	(25,400)	(25,890)	(26,480)	(27,150)	(28,030)	(28,980)	(30,080)	(31,610)
J	**Statewide System Margin (F+I)**	4,221	4,395	3,927	3,437	2,847	2,177	1,297	347	(753)	(2,283)
K	SCRs (7), (8)	684	684	684	684	684	684	684	684	684	684
L	**Statewide System Margin with SCR (J+K)**	4,905	5,079	4,611	4,121	3,531	2,861	1,981	1,031	(69)	(1,599)
M	Operating Reserve	(1,310)	(1,310)	(1,310)	(1,310)	(1,310)	(1,310)	(1,310)	(1,310)	(1,310)	(1,310)
N	**Statewide System Margin with Full Operating Reserve (L+M) (4)**	3,595	3,769	3,301	2,811	2,221	1,551	671	(279)	(1,379)	(2,909)

Notes:

1. Reflects the 2024 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 10% 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 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 August 2023 (https://www.nerc.com/pa/RAPA/gads/Pages/Reports.aspx).
3. Interchanges are based on ERAG MMWG values.
4. For informational purposes.
5. Reflects the 2024 Gold Book Forecast with flexible large loads offline.
6. Includes all gas only units that do not have a firm gas contract. Also includes reductions in units with duct burner capabilities. Duct burner derates on dual fual combined cycle units with non-firm gas account for approximately 500 MW of derated capacity.
7. SCRs are not applied for transmission security analysis of normal operations, but are included for emergency operations.
8. Includes a derate of 221 MW for SCRs.

Figure 41: Winter Peak Statewide System Margin Calculation (Flexible Large Loads Online)

Line	Item	Winter Peak - Baseline Expected Winter Weather, Normal Transfer Criteria (MW)									
		2025-26	2026-27	2027-28	2028-29	2029-30	2030-31	2031-32	2032-33	2033-34	2034-35
A	NYCA Generation (1)	40,980	42,720	42,720	42,720	42,720	42,262	42,262	42,262	42,262	42,262
B	NYCA Generation Derates (2)	(6,417)	(7,809)	(7,809)	(7,809)	(7,809)	(7,809)	(7,809)	(7,809)	(7,809)	(7,809)
C	Unavailability of Non-Firm Gas (6)	(6,319)	(6,319)	(6,319)	(6,319)	(6,319)	(5,861)	(5,861)	(5,861)	(5,861)	(5,861)
D	Temperature Based Generation Derates	0	0	0	0	0	0	0	0	0	0
E	External Area Interchanges (3)	735	735	735	735	735	735	735	735	735	735
F	**Total Resources (A+B+C+D+E)**	28,979	29,327	29,327	29,327	29,327	29,327	29,327	29,327	29,327	29,327
G	Demand Forecast (5)	(24,210)	(24,730)	(25,270)	(25,760)	(26,350)	(27,020)	(27,900)	(28,850)	(29,950)	(31,480)
H	Largest Loss-of-Source Contingency	(1,310)	(1,310)	(1,310)	(1,310)	(1,310)	(1,310)	(1,310)	(1,310)	(1,310)	(1,310)
I	**Total Capability Requirement (G+H)**	(25,520)	(26,040)	(26,580)	(27,070)	(27,660)	(28,330)	(29,210)	(30,160)	(31,260)	(32,790)
J	**Statewide System Margin (F+I)**	3,459	3,287	2,747	2,257	1,667	997	117	(833)	(1,933)	(3,463)
K	SCRs (7), (8)	684	684	684	684	684	684	684	684	684	684
L	**Statewide System Margin with SCR (J+K)**	4,143	3,971	3,431	2,941	2,351	1,681	801	(149)	(1,249)	(2,779)
M	Operating Reserve	(1,310)	(1,310)	(1,310)	(1,310)	(1,310)	(1,310)	(1,310)	(1,310)	(1,310)	(1,310)
N	**Statewide System Margin with Full Operating Reserve (L+M) (4)**	2,833	2,661	2,121	1,631	1,041	371	(509)	(1,459)	(2,559)	(4,089)

Notes:

1. Reflects the 2024 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 10% 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 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 August 2023 (https://www.nerc.com/pa/RAPA/gads/Pages/Reports.aspx).
3. Interchanges are based on ERAG MMWG values.
4. For informational purposes.
5. Reflects the 2024 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. Duct burner derates on dual fual combined cycle units with non-firm gas account for approximately 500 MW of derated capacity.
7. SCRs are not applied for transmission security analysis of normal operations, but are included for emergency operations.
8. Includes a derate of 221 MW for SCRs.

Figure 42: Winter Peak Statewide System Margin – Flexible Large Loads Comparison

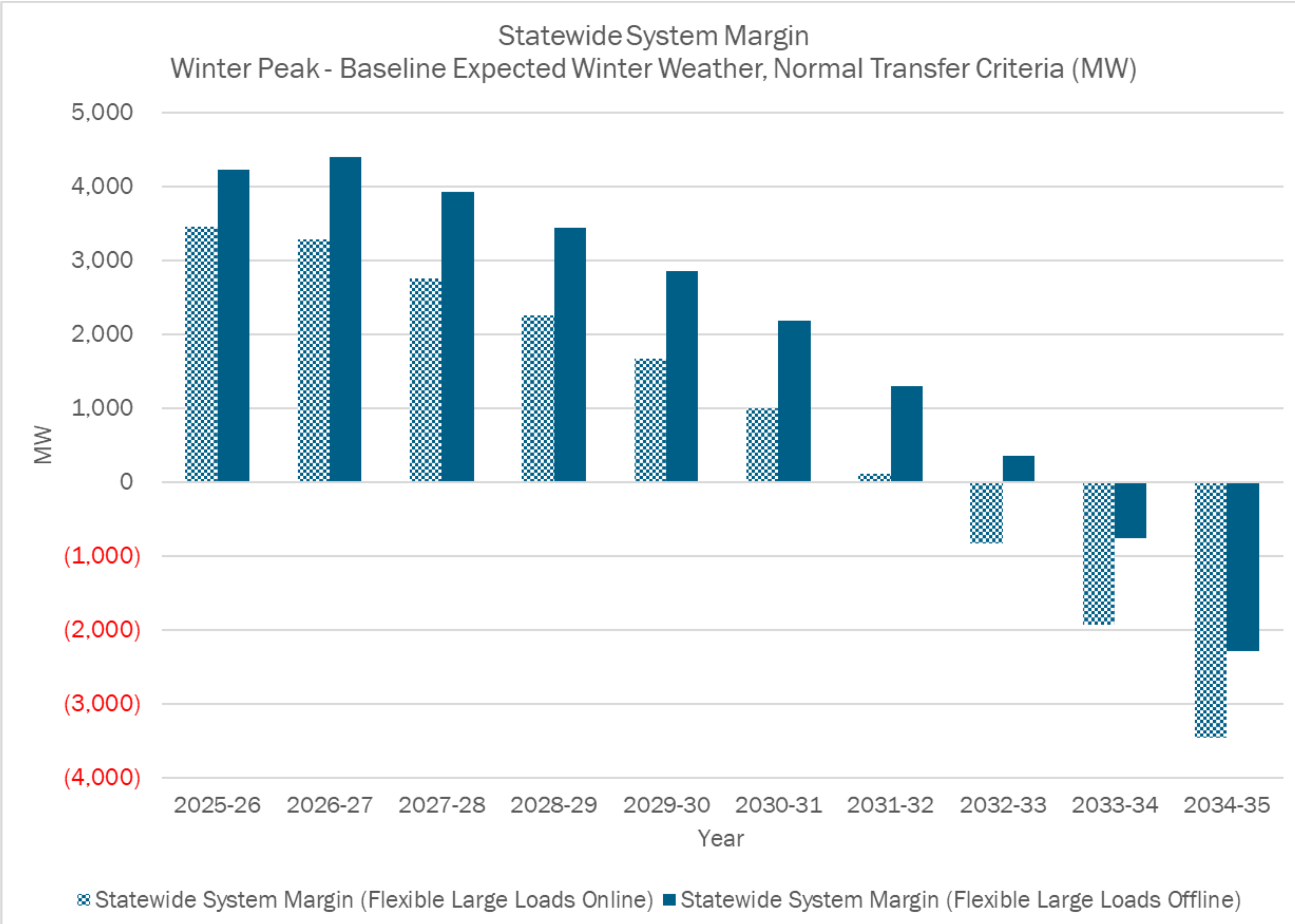


Figure 43: Winter Peak Statewide System Margin Chart (Flexible Large Loads Offline)

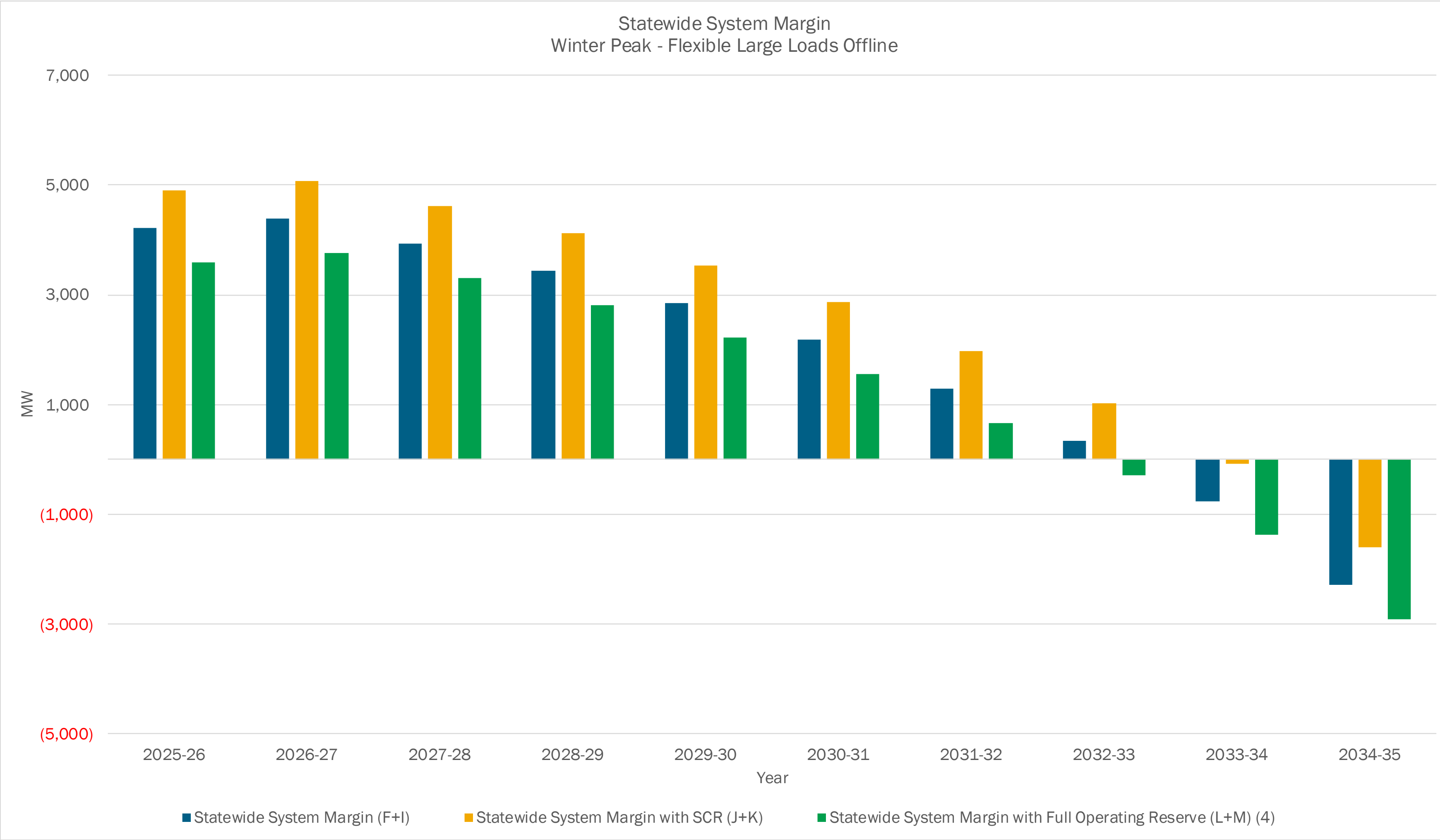
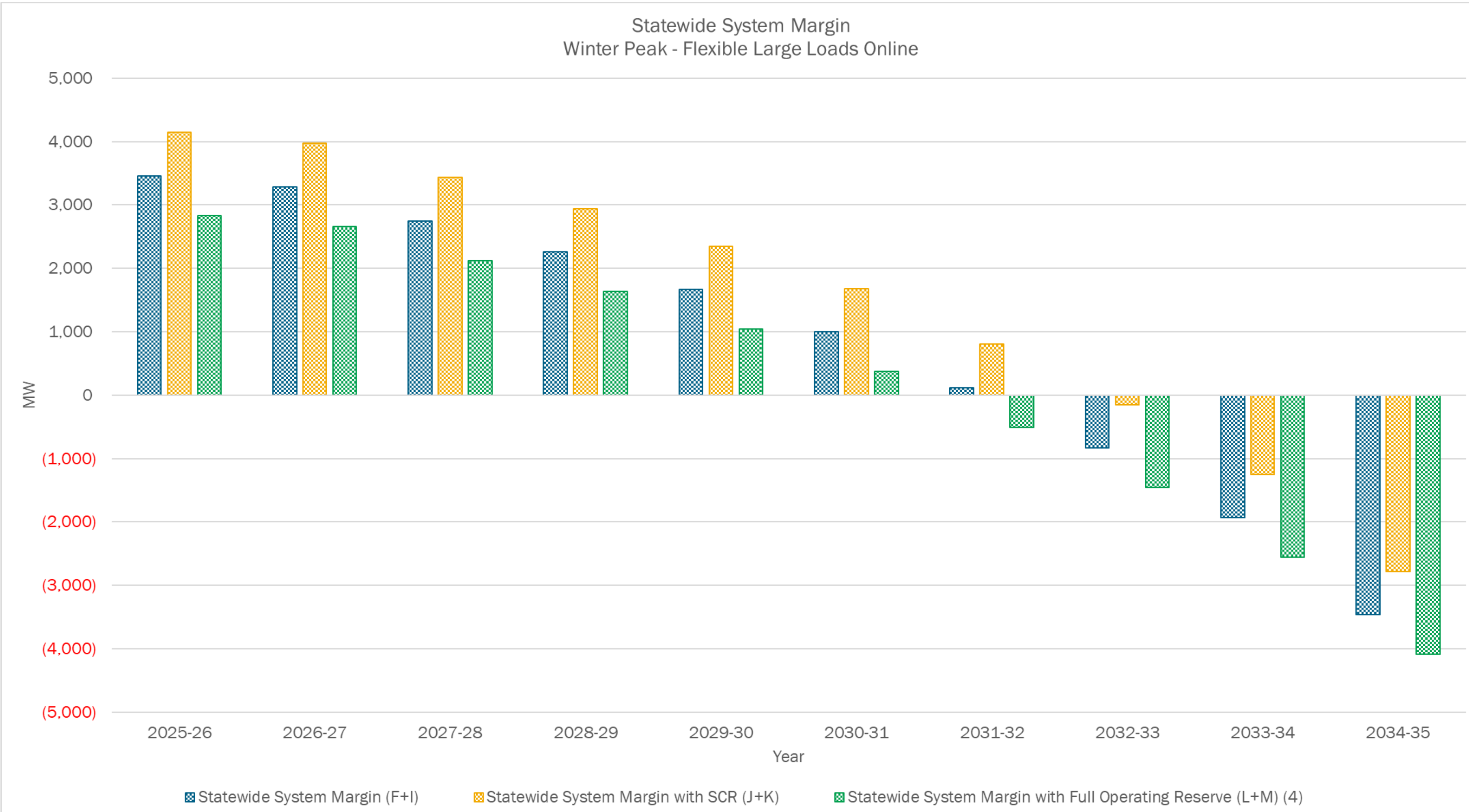


Figure 44: Winter Peak Statewide System Margin Chart (Flexible Large Loads Online)



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 2025, the limiting contingency combination is the loss of Ravenswood 3 followed by the loss of Pleasant Valley-Wood St. 345 kV (F30/F31). Starting in summer 2026, the limiting contingency combination changes to the loss of Knickerbocker – Pleasant Valley 345 kV followed by the loss of Athens-Van Wagner 345 kV (91). The limiting contingency combination for winter throughout the study period is the loss of Ravenswood 3 followed by the loss of Pleasant Valley-Wood St. 345 kV (F30/F31).

Figure 45 and Figure 46 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. Figure 47 summarizes the margin calculation tables. The Lower Hudson Valley maintains positive transmission security margins throughout the STAR study horizon.

Figure 45: Summer Peak Lower Hudson Valley Margin Calculation

Summer Peak - Baseline Expected Weather, Normal Transfer Criteria (MW)											
e	Item	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
A	G-J Demand Forecast	(15,066)	(15,118)	(15,179)	(15,244)	(15,323)	(15,414)	(15,535)	(15,701)	(15,891)	(16,056)
B	RECO Demand	(419)	(419)	(419)	(419)	(419)	(419)	(419)	(419)	(419)	(419)
C	**Total Demand (A+B)**	(15,485)	(15,537)	(15,598)	(15,663)	(15,742)	(15,833)	(15,954)	(16,120)	(16,310)	(16,475)
D	UPNY-SENY Limit (3)	5,700	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)	(11)
F	K - SENY	47	47	0	47	47	185	99	44	(33)	(96)
G	**Total SENY AC Import (D+E+F)**	5,736	4,736	4,689	4,736	4,736	4,674	4,588	4,533	4,456	4,393
H	Loss of Source Contingency	(987)	0	0	0	0	0	0	0	0	0
I	**Resource Need (C+G+H)**	(10,737)	(10,801)	(10,909)	(10,927)	(11,006)	(11,159)	(11,366)	(11,587)	(11,854)	(12,082)
J	G-J Generation (1)	13,054	13,054	13,870	13,870	13,870	13,870	13,460	13,460	13,460	13,460
K	G-J Generation Derates (2)	(1,225)	(1,228)	(1,965)	(1,967)	(1,970)	(1,971)	(1,930)	(1,931)	(1,931)	(1,933)
L	Temperature Based Generation Derates	0	0	0	0	0	0	0	0	0	0
M	Net ICAP External Imports	315	1,565	1,565	1,565	1,565	1,565	1,565	1,565	1,565	1,565
N	**Total Resources Available (J+K+L+M)**	12,145	13,392	13,470	13,469	13,466	13,464	13,096	13,094	13,094	13,093
O	**Transmission Security Margin (I+N)**	1,408	2,590	2,561	2,542	2,460	2,305	1,730	1,507	1,240	1,011
P	Higher Demand Impact	(215)	(334)	(454)	(583)	(711)	(849)	(968)	(1,071)	(1,159)	(1,278)
Q	**Higher Demand Transmission Security Margin (O+P)**	1,193	2,256	2,107	1,959	1,749	1,456	762	436	81	(267)

Notes:

1. Reflects the 2024 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 (2024 Gold Book Table I-9a) and solar PV peak reductions (2024 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 August 2023 (https://www.nerc.com/pa/RAPA/gads/Pages/Reports.aspx).
3. Limits for 2025 are based on the summer peak 2025 representations evaluated in the post-2020 RNA updates. 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 the summer peak 2034 representations evaluated in the 2024 RNA.

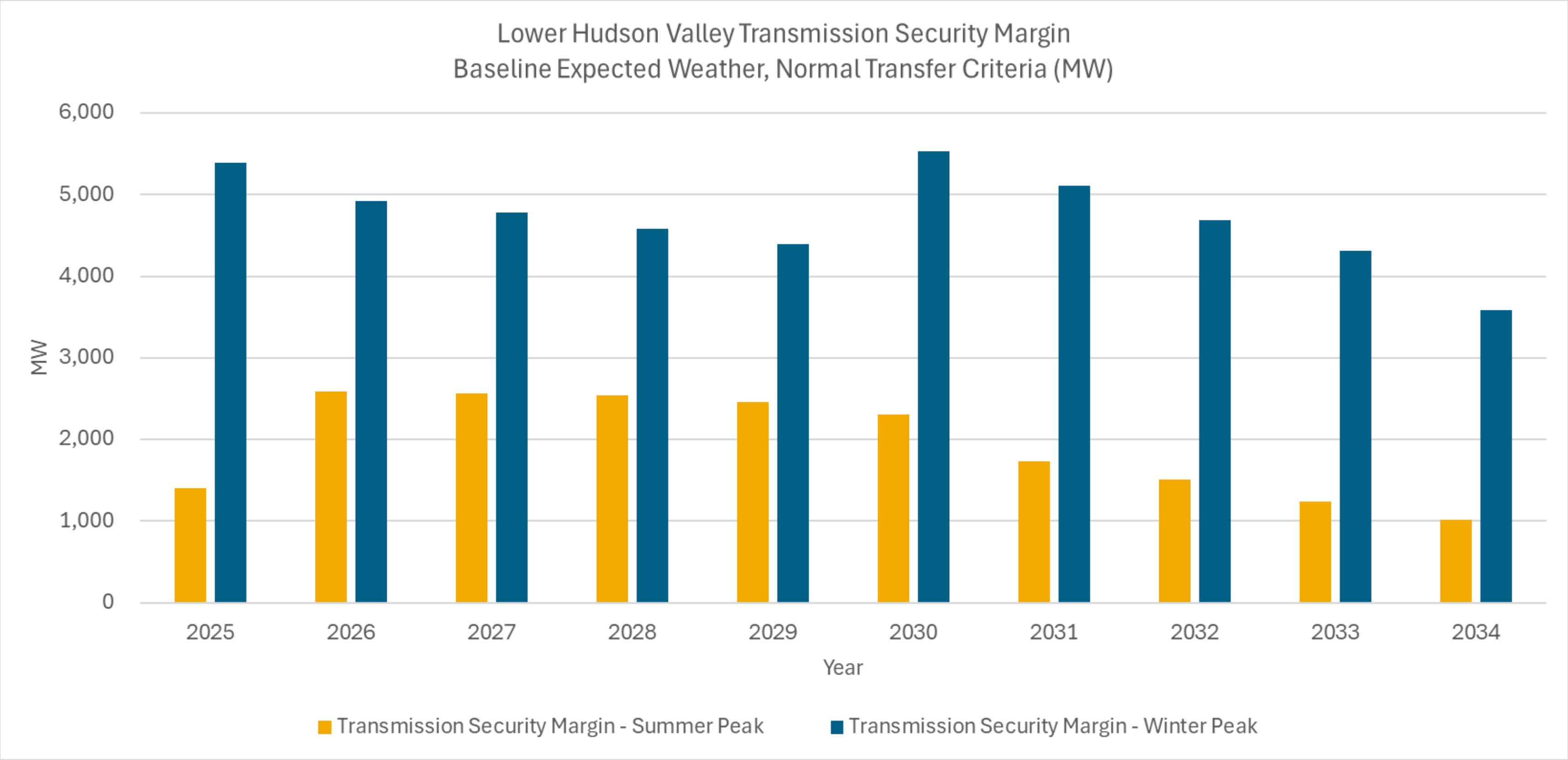
Figure 46: Winter Peak Lower Hudson Valley Margin Calculation

Winter Peak - Baseline Expected Weather, Normal Transfer Criteria (MW)											
e	Item	2025-26	2026-27	2027-28	2028-29	2029-30	2030-31	2031-32	2032-33	2033-34	2034-35
A	G-J Demand Forecast	(10,327)	(10,446)	(10,587)	(10,765)	(10,962)	(11,185)	(11,603)	(12,029)	(12,398)	(13,127)
B	RECO Demand	(231)	(231)	(231)	(243)	(243)	(243)	(243)	(243)	(248)	(248)
C	**Total Demand (A+B)**	(10,558)	(10,677)	(10,818)	(11,008)	(11,205)	(11,428)	(11,846)	(12,272)	(12,646)	(13,375)
D	UPNY-SENY Limit (3)	5,700	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)	(11)
F	K - SENY	47	47	47	47	47	1,013	1,013	1,013	1,013	1,013
G	**Total SENY AC Import (D+E+F)**	5,736	5,336	5,336	5,336	5,336	6,702	6,702	6,702	6,702	6,702
H	Loss of Source Contingency	(968)	(1,090)	(1,090)	(1,090)	(1,090)	(1,090)	(1,090)	(1,090)	(1,090)	(1,090)
I	**Resource Need (C+G+H)**	(5,790)	(6,431)	(6,572)	(6,762)	(6,959)	(5,816)	(6,234)	(6,660)	(7,034)	(7,763)
J	G-J Generation (1)	14,530	15,346	15,346	15,346	15,346	14,934	14,934	14,934	14,934	14,934
K	G-J Generation Derates (2)	(1,166)	(1,819)	(1,819)	(1,819)	(1,819)	(1,818)	(1,818)	(1,818)	(1,818)	(1,818)
L	Shortage of Gas Fuel Supply (4)	(2,495)	(2,495)	(2,495)	(2,495)	(2,495)	(2,084)	(2,084)	(2,084)	(2,084)	(2,084)
M	Temperature Based Generation Derates	0	0	0	0	0	0	0	0	0	0
N	Net ICAP External Imports	315	315	315	315	315	315	315	315	315	315
O	**Total Resources Available (J+K+L+M+N)**	11,184	11,347	11,347	11,347	11,347	11,348	11,348	11,348	11,348	11,348
P	**Transmission Security Margin (I+O)**	5,394	4,916	4,775	4,585	4,388	5,532	5,114	4,688	4,314	3,585

Notes:

1. Reflects the 2024 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 10% 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 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 August 2023
3. Limits for 2025-26 are based on the summer peak 2025 representations evaluated in the post-2020 RNA updates (as a conservative winter peak assumption these limits utilize the summer values). Limits for 2026-27 through 2029-30 are based on winter peak 2029-30 representations evaluated in the 2024 RNA. Limits for 2030-31 through 2034-35 are based on the winter peak 2034-35 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. Also includes reductions in units with duct burner capabilities.

Figure 47: Lower Hudson Valley Margin Chart – Summer and Winter



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).[28] Therefore, unlike the Lower Hudson Valley and Long Island localities, the New York City transmission security margin is calculated based on the most limiting N-1-1-0 contingency combination. As the system changes, the limiting contingency combination may also change.

In summer 2025, the most limiting N-1-1-0 contingency combination is the loss of Ravenswood 3 followed by the loss of Mott Haven – Rainey 345 kV (Q12). Starting in summer 2026 and continuing throughout the remainder of the study period, the limiting contingency combination changes to the loss of the CHPE HVDC cable followed by the loss of Ravenswood 3. In winter 2025-2026 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 in December 2025, it is scheduled at 0 MW for the winter seasons.

This assessment recognizes that there is uncertainty in the demand forecast driven by uncertainties in key assumptions such as population and economic growth, energy efficiency, the installation of BtM renewable energy resources, and electric vehicle adoption and charging patterns. These risks are considered in the transmission security margin calculations by incorporating the lower and higher forecast bounds as a range of conditions during expected weather, as shown in Figure 48. Baseline demand lies approximately in the middle of the uncertainty band and is used for the baseline margin (line-item L) in Figure 49. The upper range of this forecast band is used for the higher demand margin (line-item N). Heatwave conditions, also shown in Figure 48 are separate single forecasts.

Figure 49 shows the calculation of the New York City transmission security margin at the statewide coincident peak hour for baseline expected weather and expected load conditions for summer with normal transfer criteria. The New York City transmission security margin coincident with the statewide system peak ranges from 489 MW in summer 2026, increases to 580 in summer 2030, decreases to -17 MW by summer 2033, and decreases further to -97 MW by summer 2034 (line-item L). Figure 50 plots the summer margin results under baseline and high forecast demand levels. As shown in Figure 51, major drivers of the

[28] Con Edison, TP-7100-18 Transmission Planning Criteria, dated August 2019.

New York City margin results throughout the study period include the addition of the CHPE project, planned removal of certain NYPA generators by the summer of 2031, moderate increases in the baseline demand forecast, and significant forecast uncertainty in later study years.

The figures below also show a margin deficiency in summer 2025. This reflects the margin result without the capacity provided by certain units that are temporarily retained to continue to operate past May 2025 under the Peaker Rule to address a Near-Term Reliability Need identified in the 2023 Q2 STAR. With the retention of these generators, the New York City locality has a positive transmission security margin in 2025 under expected summer weather peak demand periods. Summer 2026 margins are positive without these retained generators due to the CHPE project's planned in-service date.

As transmission security analysis represents discrete snapshots in time of various credible combinations of system conditions, when reliability needs are identified only the magnitude of the need can be identified under those system conditions. Additional details are required to fully describe the nature of the need such as evaluating the hourly load shape and its impact on the need. To describe the nature of the New York City transmission security margin, load shapes are developed for the Zone J component of the statewide load shape. For this assessment, load shapes are not developed past 2034 and are only developed for the summer conditions.

Utilizing the load shape for the baseline expected weather summer peak day, the New York City transmission security margin for each hour is shown in Figure 52 for the 2025 summer peak day without the capacity provided by the Gowanus and Narrows barges and Figure 53 for the 2025 summer peak day with the capacity provided by those units. The hourly margins are created by using the load curve forecast for each hour in the margin calculation (Figure 49 line-item A) with additional adjustments to account for the appropriate derate for solar generation and energy limited resources in each hour (Figure 49 line-item H). All other values in the margin calculation are held constant. Hourly margin data for all years within the study period is tabulated in Figure 56.

Under the baseline forecast for coincident summer peak demand, the New York City transmission security margin would be deficient starting in 2033 with the deficiency of 17 MW for one hour and growing to 97 MW for three hours in 2034. The New York City transmission security margin for each hour is shown in Figure 54 for the 2033 summer peak day and Figure 55 for the 2034 summer peak day for the baseline forecast and high demand forecast. Accounting for uncertainties in key demand forecast assumptions, the higher bound of expected demand under baseline weather conditions (95 degrees Fahrenheit) in 2034 results in a deficiency of up to 1,137 MW over 11 hours.

Certain scenarios of extreme weather or adverse system changes present risks of worsened summer transmission security margins in New York City. Figure 57 and Figure 58 provide a summary of expected margins under these risk scenarios. Extreme weather scenarios include a 1-in-10-year heatwave and a 1-in-100-year heatwave, resulting in load levels higher than the baseline summer peak forecast. Under a 1-in-10-year heatwave, positive margins are maintained until the summer of 2031. Under a 1-in-100-year heatwave, margins are negative throughout the study period. Other risk scenarios examine the impact of adverse changes to the planned system. Delay of the CHPE HVDC transmission project results in negative margins throughout the study period if delayed indefinitely, or until a hypothetical delayed in-service date.

In addition to the risk scenarios noted above, the retirement of certain key generators or groups of generators may result in a degraded transmission security margin. Considering the summer baseline peak load transmission security margin, several different single generator outages (or combinations of generator outages) including whole plant outages, within New York City beyond those included in the STAR Base Case assumptions could result in a deficient transmission security margin. Details of specific generator outage impacts on the New York City transmission security margin are shown in Figure 66 of Appendix F. Note that margin numbers in Figure 66 are based on the high demand forecast rather than the baseline forecast.

Figure 59 shows the New York City transmission security margin calculation under winter peak baseline expected weather load conditions with normal transfer criteria. For winter peak, the margin is sufficient for all years and ranges from 2,629 MW in winter 2025-2026 to 2,319 in winter 2034-35 (line-item L). Results are presented graphically in Figure 60.

Figure 48: New York City Demand Forecasts and Forecast Uncertainty

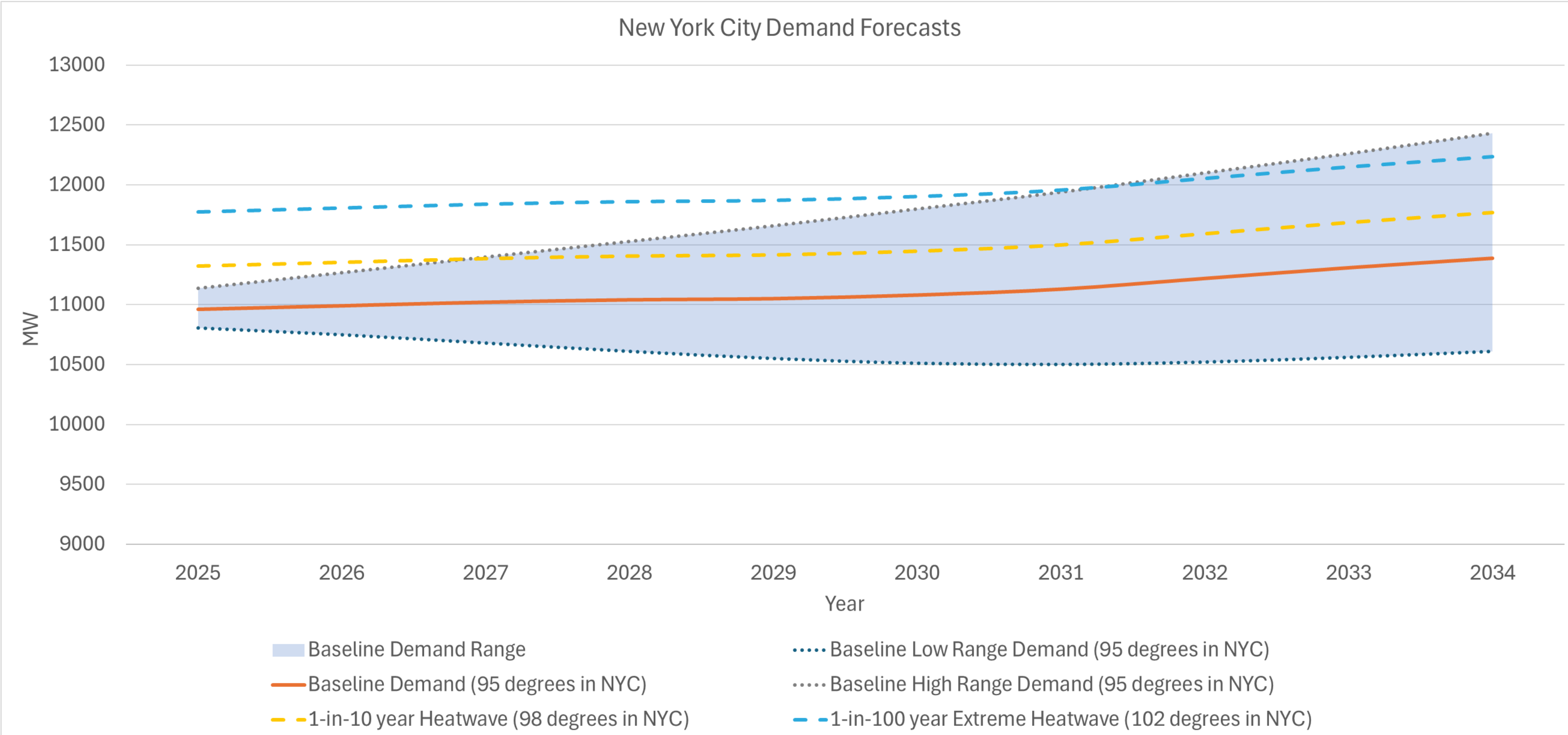


Figure 49: New York City Transmission Security Margin Calculation – Summer Peak

Summer Peak - Baseline Expected Weather, Normal Transfer Criteria (MW)											
Line	Item	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
A	**Zone J Demand Forecast (4)**	(10,960)	(10,990)	(11,020)	(11,040)	(11,050)	(11,080)	(11,130)	(11,220)	(11,310)	(11,390)
B	I+K to J (3)	3,900	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)	(11)
D	**Total J AC Import (B+C)**	3,889	4,689	4,689	4,689	4,689	4,789	4,789	4,789	4,789	4,789
E	Loss of Source Contingency	(987)	(2,237)	(2,237)	(2,237)	(2,237)	(2,237)	(2,237)	(2,237)	(2,237)	(2,237)
F	**Resource Need (A+D+E)**	(8,058)	(8,538)	(8,568)	(8,588)	(8,598)	(8,528)	(8,578)	(8,668)	(8,758)	(8,838)
G	J Generation (1)	8,104	8,104	8,920	8,920	8,920	8,920	8,510	8,510	8,510	8,510
H	J Generation Derates (2)	(642)	(642)	(1,377)	(1,377)	(1,377)	(1,377)	(1,334)	(1,334)	(1,334)	(1,334)
I	Temperature Based Generation Derates	0	0	0	0	0	0	0	0	0	0
J	Net ICAP External Imports	315	1,565	1,565	1,565	1,565	1,565	1,565	1,565	1,565	1,565
K	**Total Resources Available (G+H+I+J)**	7,777	9,027	9,109	9,109	9,109	9,109	8,741	8,741	8,741	8,741
L	**Baseline Transmission Security Margin (F+K)**	(281)	489	540	520	510	580	163	73	(17)	(97)
M	Higher Demand Impact	(180)	(280)	(380)	(490)	(610)	(720)	(810)	(880)	(950)	(1,040)
N	**Higher Demand Transmission Security Margin (L+M)**	(461)	209	160	30	(100)	(140)	(647)	(807)	(967)	(1,137)

Notes:

1. Reflects the 2024 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 (2024 Gold Book Table I-9a) and solar PV peak reductions (2024 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 August 2023 (https://www.nerc.com/pa/RAPA/gads/Pages/Reports.aspx).
3. The limit 2025 is based on the summer peak 2025 representations evaluated in the post-2020 RNA updates. 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. Reflects the 2024 Gold Book Forecast.

Figure 50: New York City Transmission Security Margin Results – Summer Peak

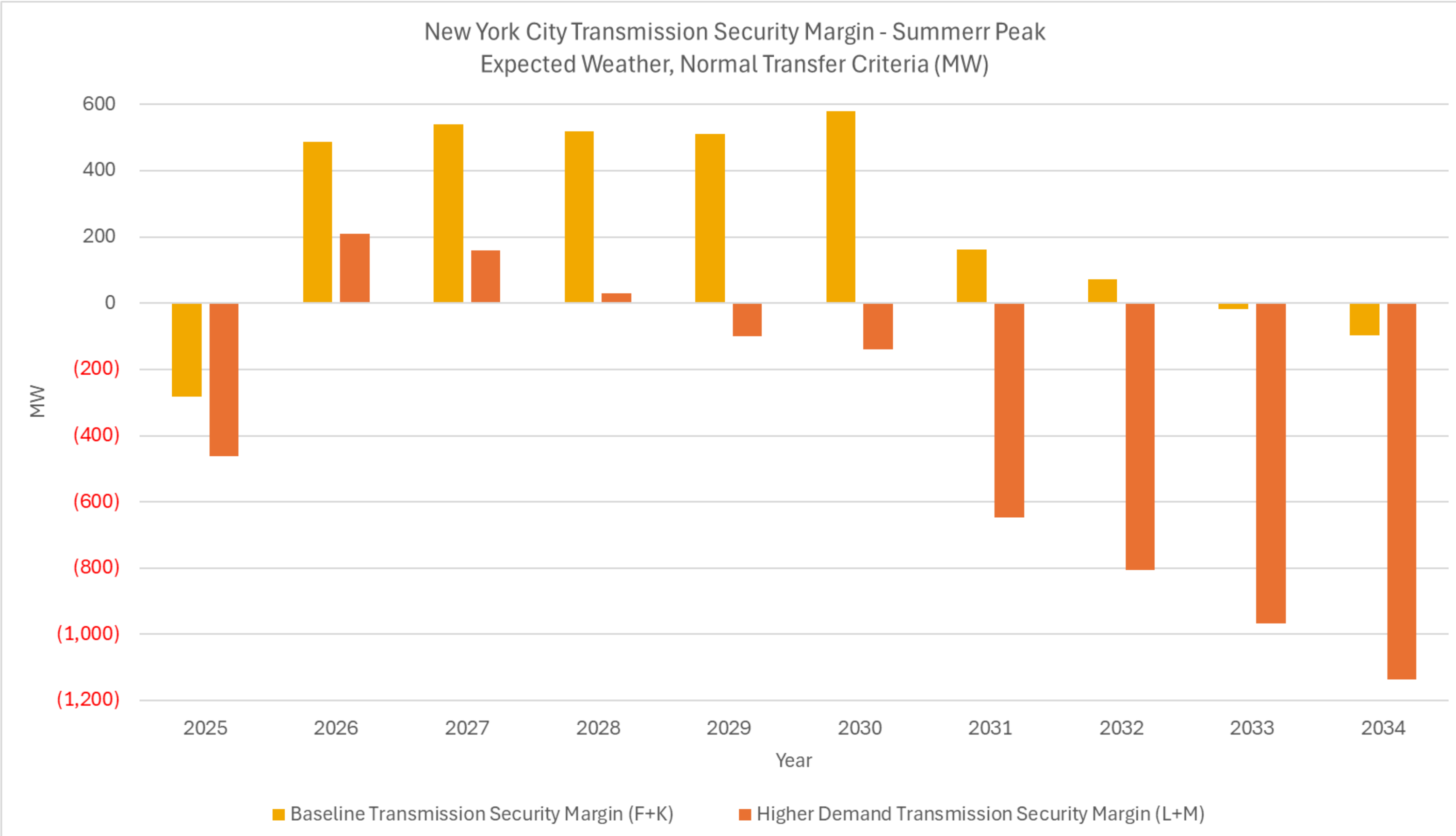


Figure 51: New York City Transmission Security Margin Summary – Summer Peak

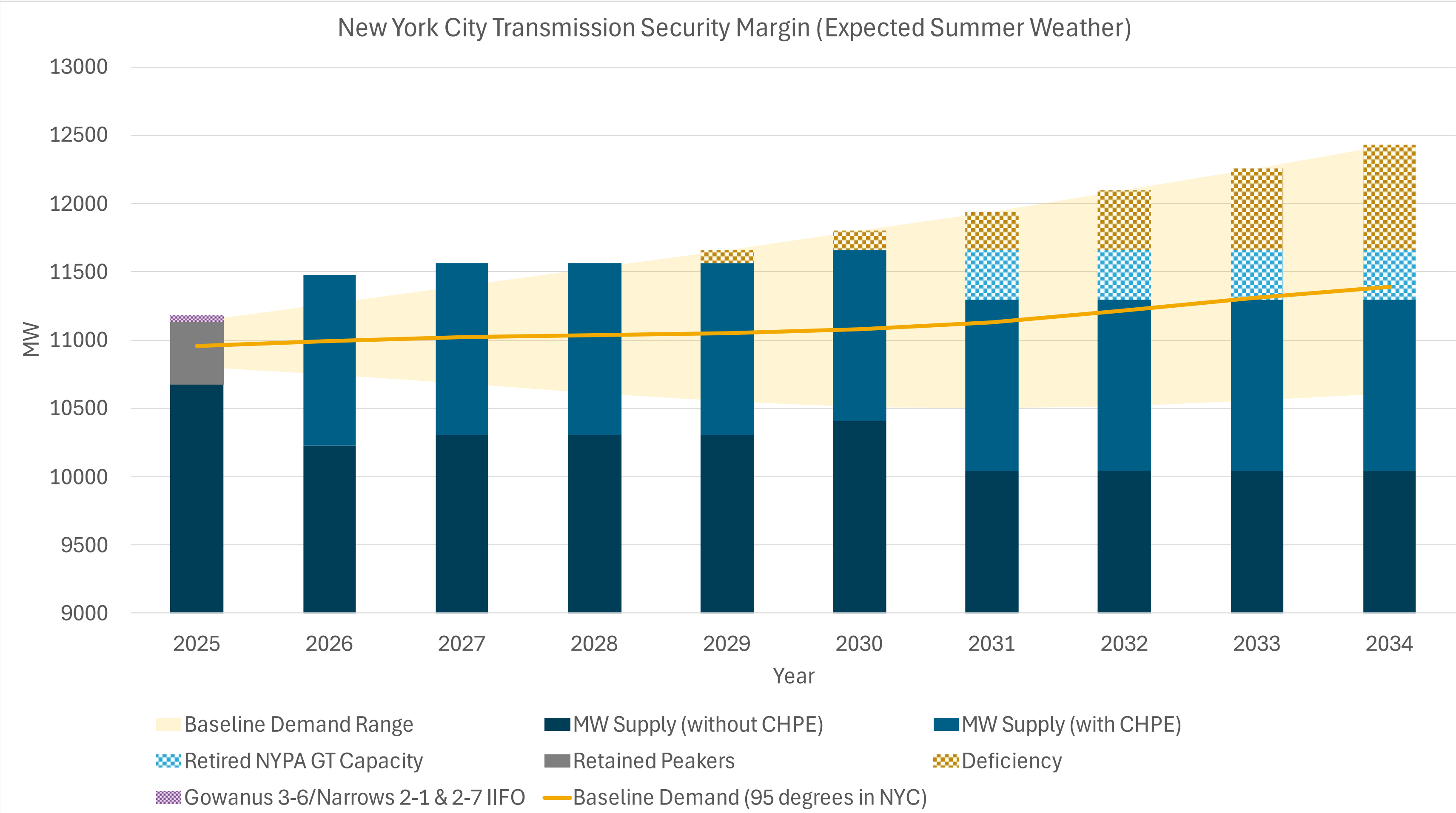


Figure 52: New York City Hourly Transmission Security Margin – 2025 Summer Peak Day – No Retained Peakers

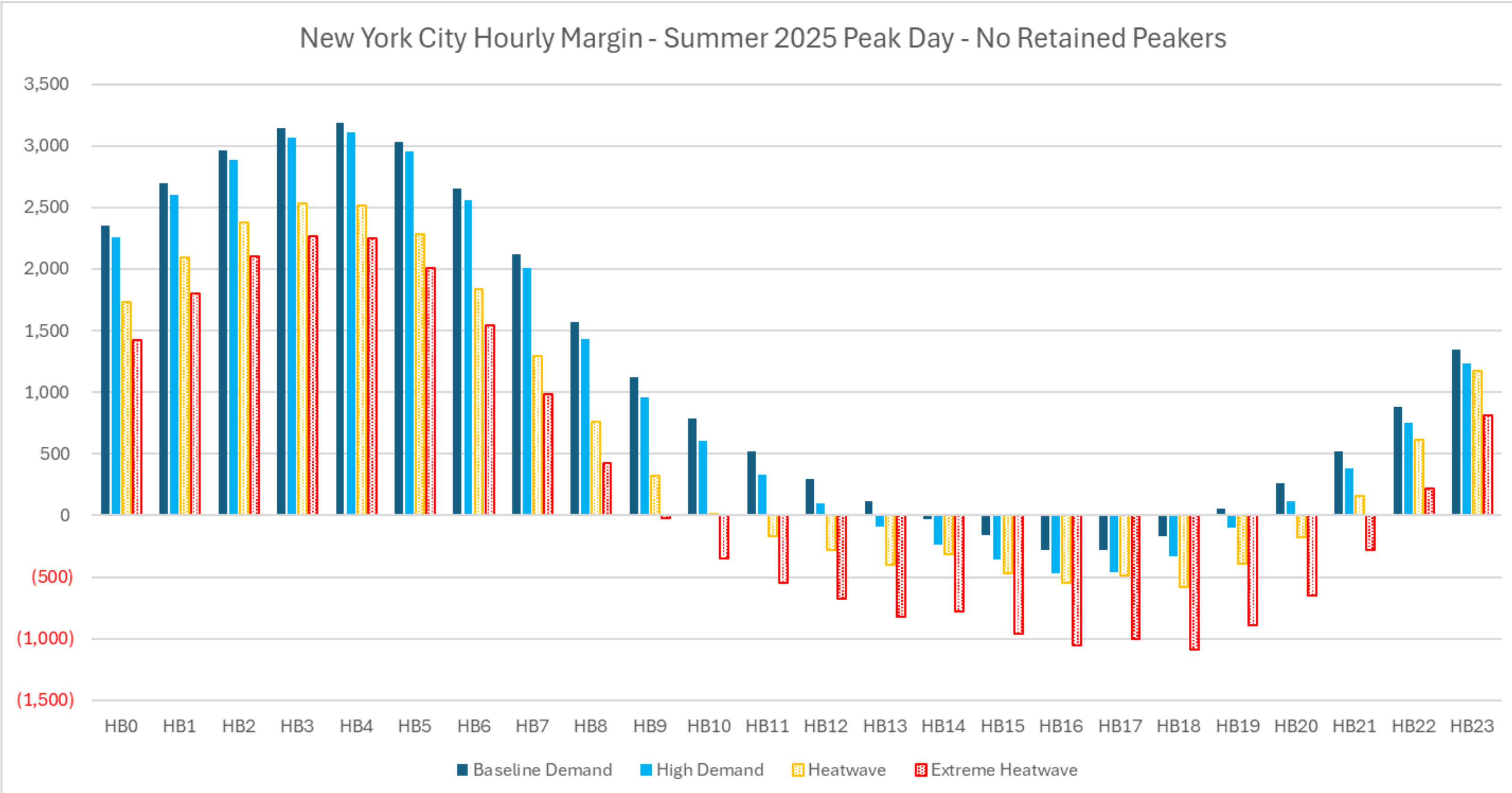


Figure 53: New York City Hourly Transmission Security Margin – 2025 Summer Peak Day – With Retained Peakers

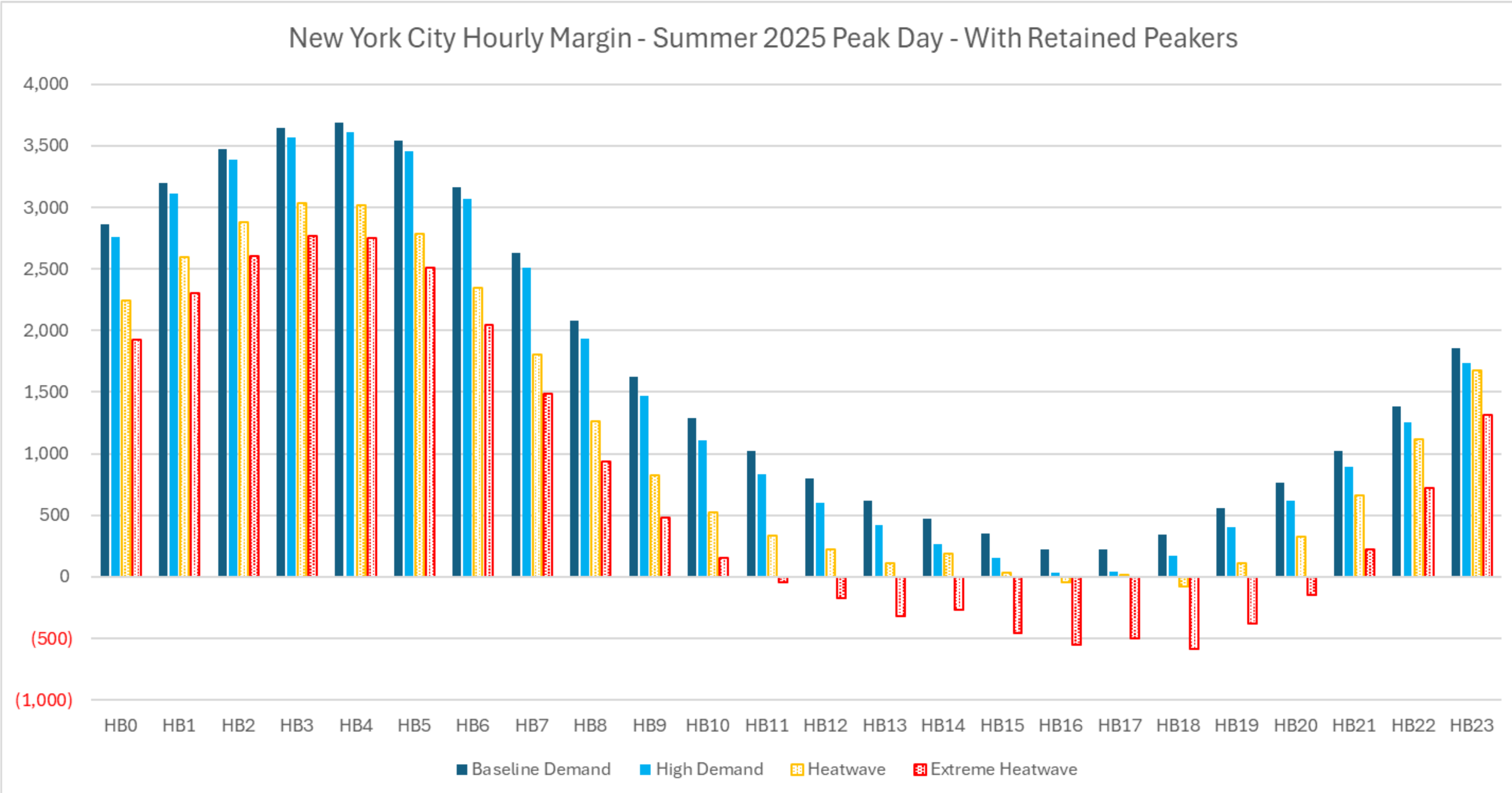


Figure 54: New York City Hourly Transmission Security Margin – 2033 Summer Peak Day

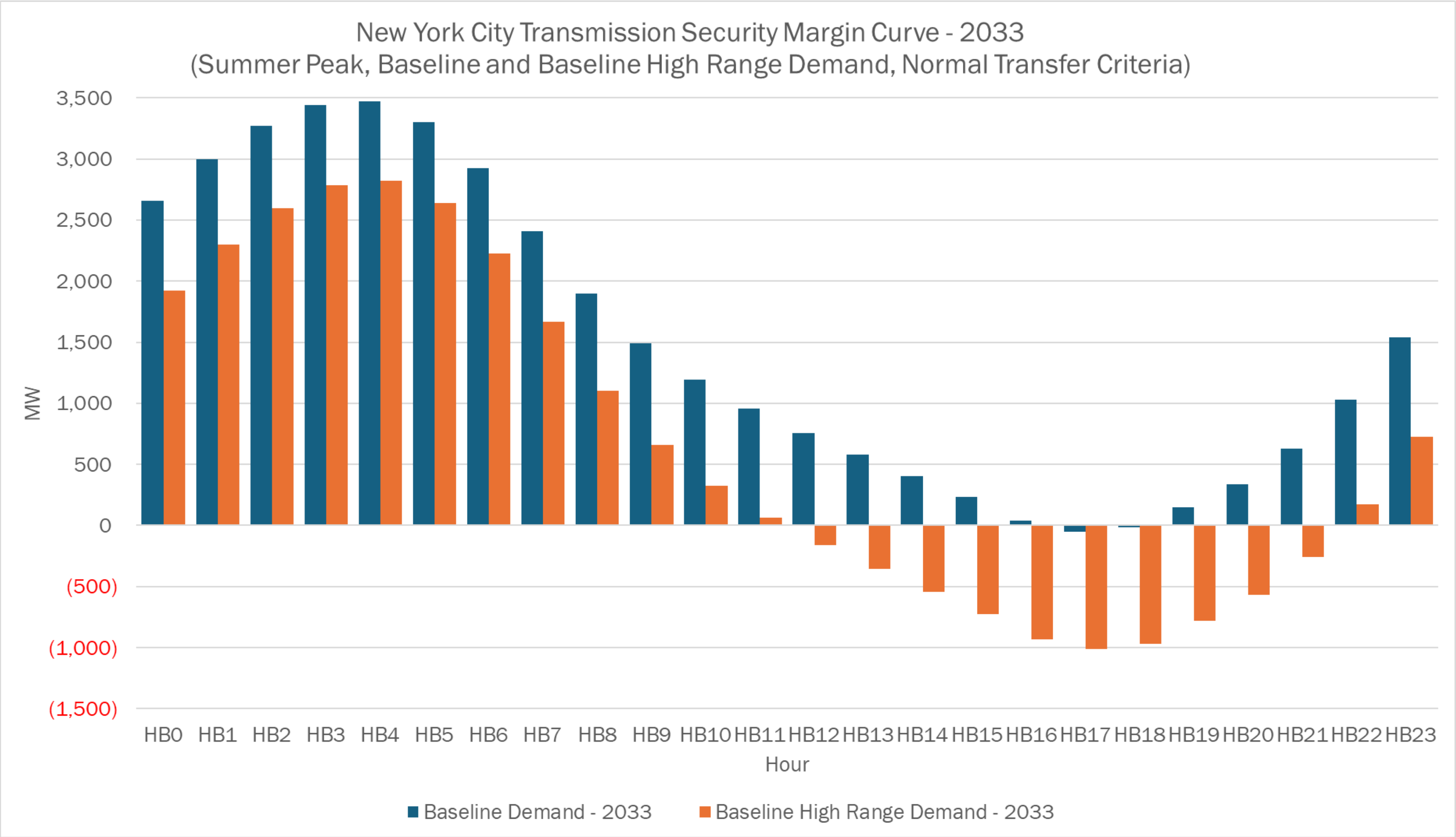


Figure 55: New York City Hourly Transmission Security Margin – 2034 Summer Peak Day

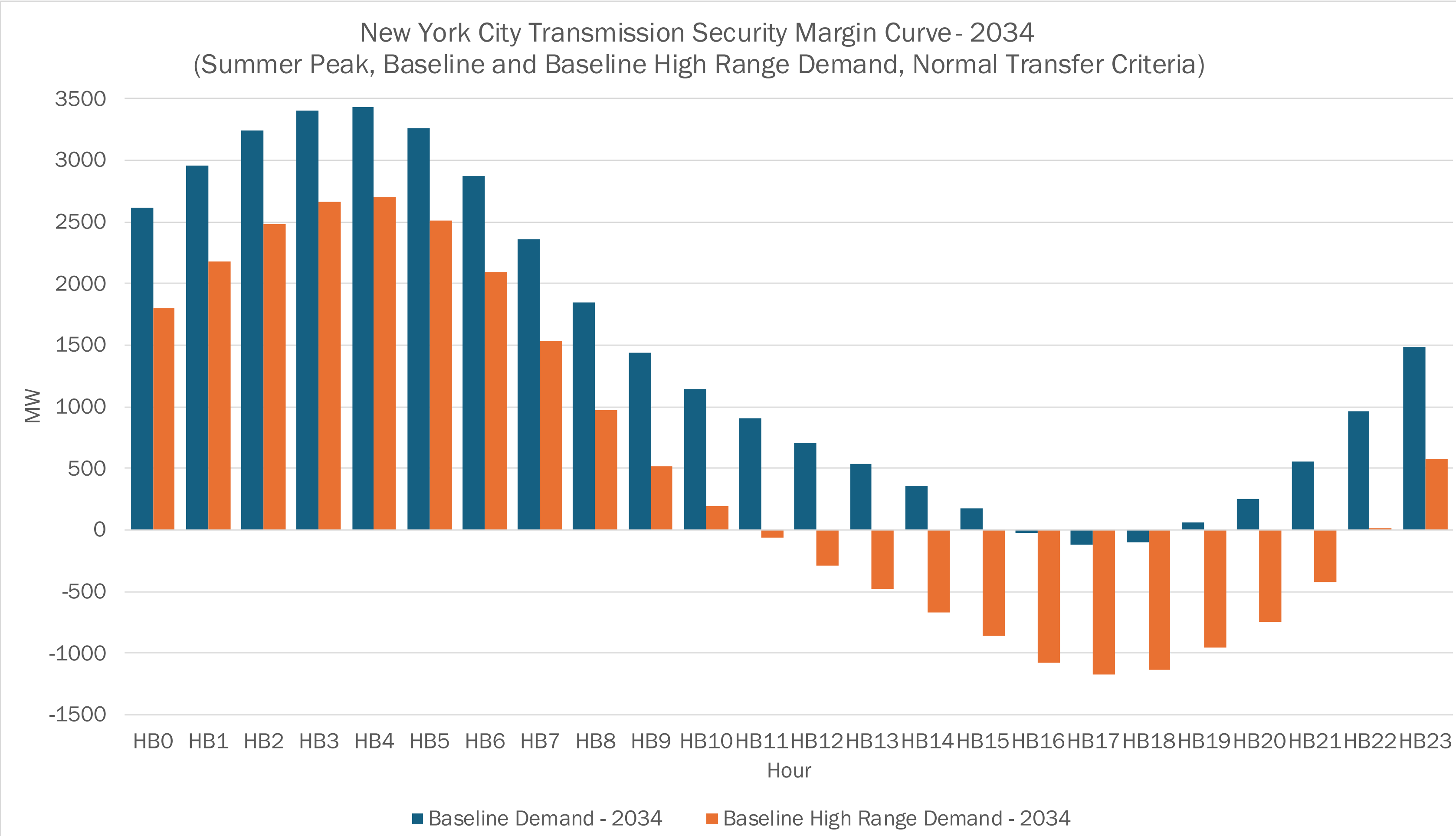


Figure 56: New York City Hourly Transmission Security Margin – 2025 through 2034 Summer Peak Days

Summer Peak - Baseline Expected Summer Weather, Normal Transfer Criteria (MW)										
J Transmission Security Margin										
Hour	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
HB0	2,356	3,022	3,070	3,074	3,074	3,169	2,780	2,719	2,658	2,618
HB1	2,694	3,360	3,408	3,414	3,415	3,509	3,121	3,060	2,998	2,961
HB2	2,967	3,634	3,682	3,689	3,690	3,784	3,396	3,336	3,274	3,237
HB3	3,142	3,810	3,856	3,863	3,863	3,956	3,568	3,507	3,443	3,405
HB4	3,184	3,852	3,898	3,903	3,902	3,992	3,602	3,538	3,472	3,431
HB5	3,036	3,703	3,747	3,752	3,749	3,836	3,442	3,375	3,304	3,258
HB6	2,655	3,322	3,371	3,375	3,373	3,460	3,066	2,996	2,924	2,874
HB7	2,123	2,795	2,850	2,857	2,858	2,947	2,553	2,483	2,410	2,358
HB8	1,572	2,250	2,316	2,328	2,335	2,428	2,038	1,969	1,899	1,847
HB9	1,124	1,809	1,884	1,901	1,914	2,012	1,623	1,558	1,490	1,437
HB10	784	1,476	1,559	1,580	1,599	1,702	1,316	1,254	1,191	1,139
HB11	518	1,215	1,303	1,326	1,351	1,457	1,075	1,017	958	909
HB12	295	993	1,086	1,109	1,138	1,246	867	812	757	711
HB13	117	815	907	929	959	1,068	688	635	581	536
HB14	(34)	660	750	768	795	901	518	462	405	357
HB15	(156)	531	615	627	646	747	357	295	233	179
HB16	(278)	398	473	474	485	577	178	107	37	(26)
HB17	(281)	384	447	437	438	518	110	30	(51)	(122)
HB18	(165)	489	540	520	510	580	163	73	(17)	(97)
HB19	54	702	744	717	700	763	340	245	148	64
HB20	260	905	943	915	895	958	534	437	340	256
HB21	521	1,168	1,207	1,183	1,166	1,234	815	724	631	554
HB22	879	1,528	1,569	1,553	1,540	1,613	1,201	1,117	1,031	963
HB23	1,349	2,002	2,044	2,035	2,025	2,104	1,699	1,621	1,541	1,482

Summer Peak - Higher Policy with Expected Summer Weather, Normal Transfer Criteria (MW)										
J Transmission Security Margin										
Hour	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
HB0	2,259	2,829	2,787	2,677	2,597	2,598	2,143	2,038	1,924	1,803
HB1	2,605	3,180	3,138	3,031	2,957	2,962	2,509	2,409	2,297	2,177
HB2	2,884	3,464	3,422	3,317	3,247	3,256	2,806	2,708	2,598	2,480
HB3	3,063	3,646	3,605	3,499	3,431	3,441	2,991	2,895	2,785	2,666
HB4	3,107	3,690	3,648	3,543	3,473	3,482	3,030	2,932	2,819	2,698
HB5	2,955	3,536	3,494	3,385	3,314	3,319	2,862	2,758	2,641	2,513
HB6	2,561	3,140	3,099	2,992	2,915	2,917	2,457	2,349	2,227	2,095
HB7	2,009	2,587	2,552	2,447	2,368	2,367	1,904	1,791	1,666	1,530
HB8	1,433	2,014	1,987	1,888	1,810	1,809	1,344	1,231	1,105	969
HB9	963	1,549	1,529	1,436	1,359	1,359	896	780	656	519
HB10	607	1,195	1,184	1,096	1,020	1,023	562	446	323	191
HB11	328	919	913	828	751	758	298	184	65	(65)
HB12	97	687	683	601	522	531	71	(42)	(160)	(286)
HB13	(86)	502	498	414	332	339	(121)	(236)	(353)	(480)
HB14	(237)	345	337	250	162	164	(301)	(421)	(542)	(673)
HB15	(355)	218	204	108	13	5	(467)	(596)	(724)	(862)
HB16	(470)	92	66	(40)	(149)	(167)	(650)	(791)	(930)	(1,078)
HB17	(461)	88	51	(67)	(188)	(217)	(714)	(865)	(1,014)	(1,174)
HB18	(330)	209	160	30	(100)	(140)	(647)	(807)	(967)	(1,137)
HB19	(98)	437	381	243	108	63	(450)	(615)	(779)	(956)
HB20	116	651	592	452	317	271	(240)	(404)	(569)	(745)
HB21	386	922	864	728	600	561	58	(98)	(256)	(425)
HB22	752	1,294	1,238	1,107	991	960	466	321	174	15
HB23	1,233	1,782	1,729	1,604	1,500	1,478	995	863	724	575

Summer Peak - Heatwave, Emergency Transfer Criteria (MW)										
J Transmission Security Margin										
Hour	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
HB0	1,737	2,527	2,593	2,484	2,486	2,582	2,192	2,031	1,994	1,956
HB1	2,095	2,887	2,955	2,849	2,852	2,945	2,556	2,401	2,366	2,328
HB2	2,378	3,173	3,243	3,139	3,142	3,234	2,845	2,695	2,661	2,624
HB3	2,533	3,329	3,400	3,297	3,300	3,390	3,001	2,853	2,818	2,781
HB4	2,513	3,308	3,378	3,273	3,275	3,362	2,971	2,821	2,784	2,744
HB5	2,284	3,077	3,144	3,035	3,034	3,118	2,724	2,566	2,525	2,479
HB6	1,839	2,632	2,700	2,587	2,586	2,670	2,274	2,108	2,065	2,016
HB7	1,297	2,097	2,171	2,055	2,057	2,143	1,748	1,573	1,529	1,477
HB8	761	1,572	1,655	1,541	1,550	1,641	1,248	1,069	1,027	975
HB9	324	1,144	1,235	1,122	1,136	1,232	842	660	620	568
HB10	17	843	941	831	852	952	566	384	347	296
HB11	(171)	658	759	651	677	781	398	216	182	134
HB12	(281)	548	648	543	574	681	300	119	86	41
HB13	(397)	426	523	420	452	560	179	(4)	(39)	(83)
HB14	(315)	497	587	243	272	379	(5)	(195)	(236)	(282)
HB15	(470)	330	410	300	324	425	36	(165)	(215)	(265)
HB16	(547)	237	302	183	197	289	(110)	(324)	(386)	(445)
HB17	(489)	280	331	202	205	286	(123)	(350)	(424)	(493)
HB18	(580)	175	210	310	300	369	(51)	(288)	(375)	(452)
HB19	(391)	358	385	240	222	284	(142)	(383)	(476)	(559)
HB20	(178)	571	598	451	430	491	64	(173)	(266)	(348)
HB21	158	915	950	808	791	856	435	210	126	50
HB22	616	1,382	1,425	1,291	1,278	1,348	934	724	650	582
HB23	1,170	1,944	1,995	1,869	1,858	1,934	1,525	1,332	1,268	1,207

Summer Peak - 1-in-100-Year Extreme Heatwave, Emergency Transfer Criteria (MW)										
J Transmission Security Margin										
Hour	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
HB0	1,423	2,212	2,277	2,170	2,172	2,266	1,876	1,704	1,667	1,627
HB1	1,800	2,591	2,659	2,554	2,557	2,649	2,259	2,094	2,058	2,020
HB2	2,100	2,893	2,963	2,861	2,863	2,955	2,566	2,406	2,371	2,334
HB3	2,265	3,060	3,131	3,029	3,031	3,121	2,731	2,574	2,539	2,500
HB4	2,245	3,039	3,108	3,004	3,005	3,093	2,701	2,541	2,504	2,462
HB5	2,005	2,796	2,863	2,754	2,754	2,838	2,443	2,275	2,233	2,186
HB6	1,542	2,334	2,401	2,288	2,288	2,371	1,975	1,798	1,754	1,703
HB7	983	1,781	1,854	1,739	1,741	1,827	1,431	1,245	1,200	1,146
HB8	429	1,239	1,322	1,209	1,217	1,309	915	724	681	628
HB9	(24)	795	886	774	789	885	494	300	258	205
HB10	(347)	479	576	467	489	589	202	7	(31)	(82)
HB11	(550)	278	378	272	299	403	20	(175)	(210)	(259)
HB12	(679)	148	249	146	177	285	(96)	(291)	(325)	(371)
HB13	(823)	(1)	97	(5)	28	137	(245)	(442)	(478)	(523)
HB14	(775)	37	128	(215)	(186)	(78)	(463)	(668)	(710)	(757)
HB15	(958)	(159)	(80)	(188)	(164)	(62)	(453)	(669)	(720)	(773)
HB16	(1,055)	(272)	(207)	(326)	(312)	(220)	(621)	(851)	(915)	(976)
HB17	(1,002)	(254)	(205)	(314)	(312)	(231)	(642)	(886)	(962)	(1,034)
HB18	(1,091)	(339)	(306)	(206)	(217)	(149)	(571)	(825)	(915)	(996)
HB19	(886)	(141)	(115)	(262)	(281)	(220)	(649)	(907)	(1,003)	(1,089)
HB20	(651)	95	121	(27)	(49)	11	(419)	(673)	(769)	(854)
HB21	(279)	475	508	366	348	412	(11)	(252)	(339)	(417)
HB22	216	980	1,021	888	873	943	527	303	227	157
HB23	809	1,582	1,630	1,506	1,495	1,569	1,159	953	887	826

Figure 57: New York City Transmission Security Margin Risks

New York City Transmission Security Margin Scenarios		2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
-	Base Case with Baseline Forecast	(281)	489	540	520	510	580	163	73	(17)	(97)
1	CHPE Unavailability Scenario	(281)	(311)	(260)	(280)	(290)	(120)	(537)	(627)	(717)	(797)
2	1-in-10 Year Heatwave	(489)	280	331	310	300	369	(51)	(144)	(237)	(320)
3	1-in-100 Year Heatwave	(1002)	(235)	(185)	(206)	(217)	(149)	(571)	(668)	(764)	(850)
Risk Descriptions:											
1. This scenario shows the unavailability of CHPE.											
2. This scenario shows the New York City transmission security margin for the statewide coincident peak hour under the 1-in-10-year heatwave condition with the assumption that the system is using emergency transfer criteria.											
3. This scenario shows the New York City transmission security margin for the statewide coincident peak hour under the 1-in-100-year heatwave condition with the assumption that the system is using emergency transfer criteria.											

Figure 58: New York City Transmission Security Margin Risks

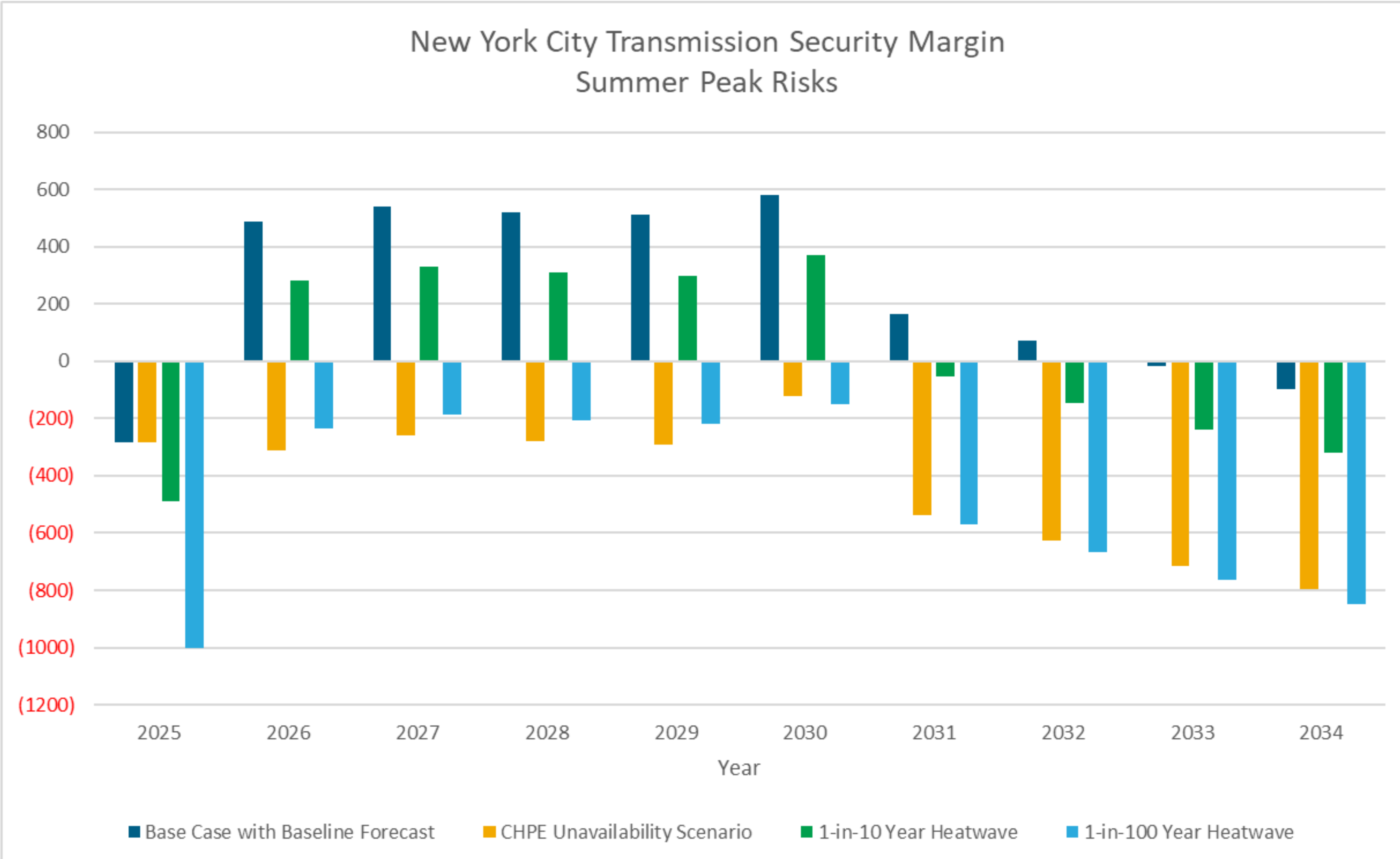


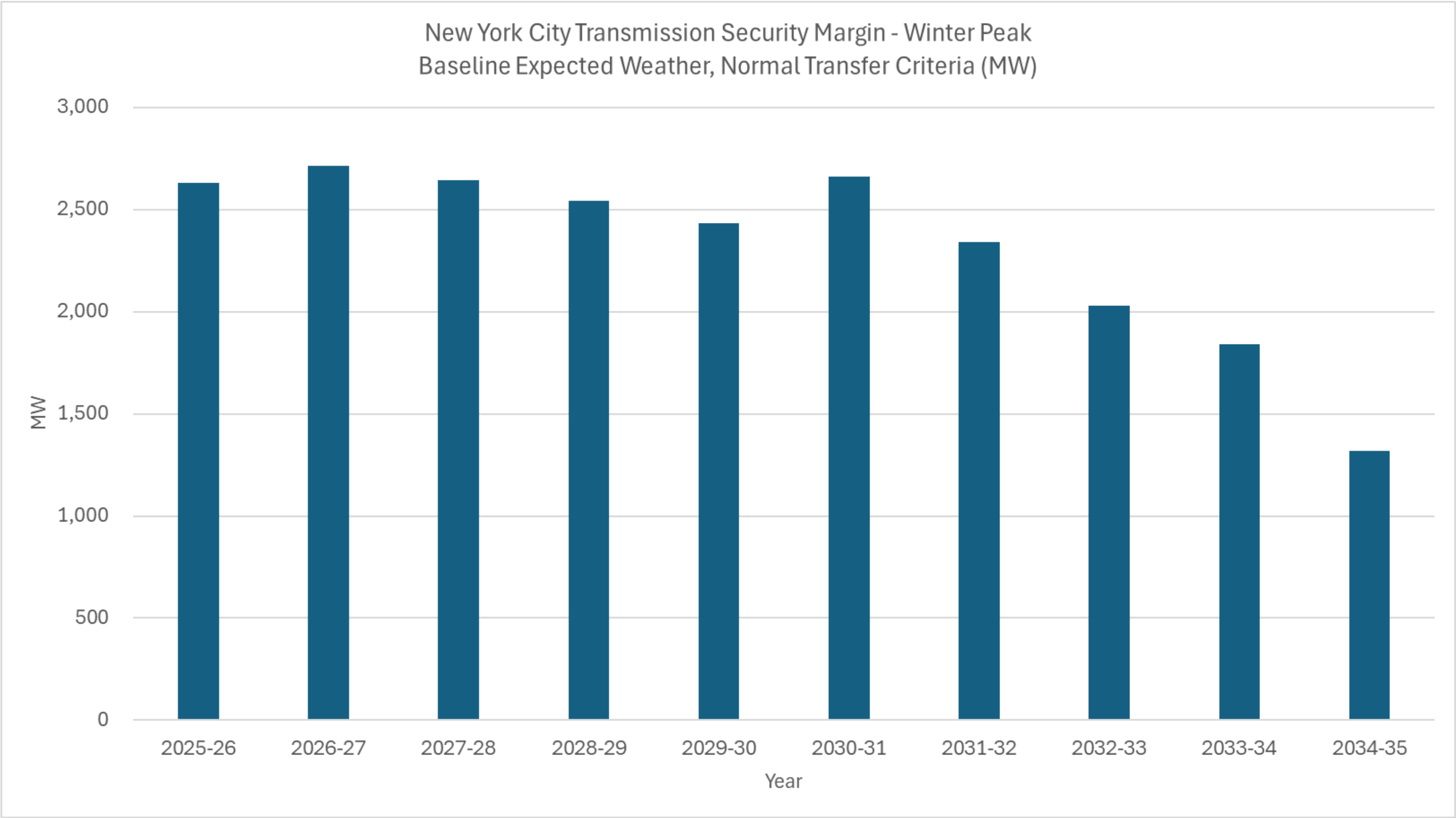
Figure 59: New York City Transmission Security Margin Calculation – Winter Peak

Winter Peak - Baseline Expected Weather, Normal Transfer Criteria (MW)											
Line	Item	2025-26	2026-27	2027-28	2028-29	2029-30	2030-31	2031-32	2032-33	2033-34	2034-35
A	**Zone J Demand Forecast (4)**	(7,410)	(7,490)	(7,560)	(7,660)	(7,770)	(7,910)	(8,230)	(8,540)	(8,730)	(9,250)
B	I+K to J (3), (4)	3,900	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)	(11)
D	**Total J AC Import (B+C)**	3,889	3,889	3,889	3,889	3,889	4,889	4,889	4,889	4,889	4,889
E	Loss of Source Contingency	(996)	(996)	(996)	(996)	(996)	(1,630)	(1,630)	(1,630)	(1,630)	(1,630)
F	**Resource Need (A+D+E)**	(4,517)	(4,597)	(4,667)	(4,767)	(4,877)	(4,651)	(4,971)	(5,281)	(5,471)	(5,991)
G	J Generation (1)	9,362	10,178	10,178	10,178	10,178	9,766	9,766	9,766	9,766	9,766
H	J Generation Derates (2)	(595)	(1,248)	(1,248)	(1,248)	(1,248)	(1,247)	(1,247)	(1,247)	(1,247)	(1,247)
I	Unavailability of Non-Firm Gas (5)	(1,936)	(1,936)	(1,936)	(1,936)	(1,936)	(1,524)	(1,524)	(1,524)	(1,524)	(1,524)
J	Temperature Based Generation Derates	0	0	0	0	0	0	0	0	0	0
K	Net ICAP External Imports	315	315	315	315	315	315	315	315	315	315
L	**Total Resources Available (G+H+I+J+K)**	7,146	7,309	7,309	7,309	7,309	7,310	7,310	7,310	7,310	7,310
M	**Transmission Security Margin (F+L)**	2,629	2,712	2,642	2,542	2,432	2,659	2,339	2,029	1,839	1,319

Notes:

1. Reflects the 2024 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 10% 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 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 August 2023
3. Limits for 2025-26 are based on the summer peak 2025 representations evaluated in the post-2020 RNA updates (as a conservative winter peak assumption these limits utilize the summer values). Limits for 2026-27 through 2029-30 are based on winter peak 2029-30 representations evaluated in the 2024 RNA. Limits for 2030-31 through 2034-35 are based on the winter peak 2034-35 representations evaluated in the 2024 RNA.
4. Reflects the 2024 Gold Book Forecast.
5. 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.

Figure 60: New York City Transmission Security Margin Results - Winter Peak



Long Island (Zone K)

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

For summer 2025 through summer 2029, the most limiting 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 Long Island Public Policy transmission project is in service, the limiting contingency combination changes to the loss of the Y50 cable followed by a stuck breaker event at East Garden City. For winter 2025-2026 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 Long Island Public Policy transmission 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).

Figure 61 and Figure 62 show the calculation of the summer and winter Long Island transmission security margin baseline expected weather, expected load conditions for the statewide coincident peak hour with normal transfer criteria. Figure 63 summarizes the margin calculation tables. Long Island maintains positive transmission security margins throughout the STAR study horizon. Significant increases in transmission security margins are seen after the Long Island Public Policy transmission project is placed in service.

Figure 61: Summer Peak Long Island Margin Calculation

Summer Peak - Baseline Expected Weather, Normal Transfer Criteria (MW)											
Line	Item	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
A	**Zone K Demand Forecast (3)**	(4,956)	(4,955)	(4,968)	(4,982)	(5,009)	(5,030)	(5,074)	(5,129)	(5,205)	(5,268)
B	I+J to K	900	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	0
D	**Total K AC Import (B+C)**	900	900	900	900	900	2,200	2,200	2,200	2,200	2,200
E	Loss of Source Contingency	(660)	(660)	(660)	(660)	(660)	0	0	0	0	0
F	**Resource Need (A+D+E)**	(4,716)	(4,715)	(4,728)	(4,742)	(4,769)	(2,830)	(2,874)	(2,929)	(3,005)	(3,068)
G	K Generation (1)	5,097	6,021	6,021	6,021	6,021	6,021	5,976	5,976	5,976	5,976
H	K Generation Derates (2)	(630)	(1,463)	(1,464)	(1,465)	(1,465)	(1,466)	(1,463)	(1,463)	(1,464)	(1,464)
I	Temperature Based Generation Derates	0	0	0	0	0	0	0	0	0	0
J	Net ICAP External Imports	660	660	660	660	660	660	660	660	660	660
K	**Total Resources Available (G+H+I+J)**	5,127	5,218	5,217	5,216	5,216	5,215	5,173	5,173	5,172	5,172
L	**Transmission Security Margin (F+K)**	411	503	489	474	447	2,385	2,299	2,244	2,167	2,104
M	Higher Demand Impact	(43)	(66)	(80)	(102)	(121)	(157)	(186)	(220)	(244)	(283)
N	**Higher Demand Transmission Security Margin (L+M)**	368	437	409	372	326	2,228	2,113	2,024	1,923	1,821

Notes:

1. Reflects the 2024 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 (2024 Gold Book Table I-9a) and solar PV peak reductions (2024 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 August 2023 (https://www.nerc.com/pa/RAPA/gads/Pages/Reports.aspx).
3. Reflects the 2024 Gold Book Forecast.

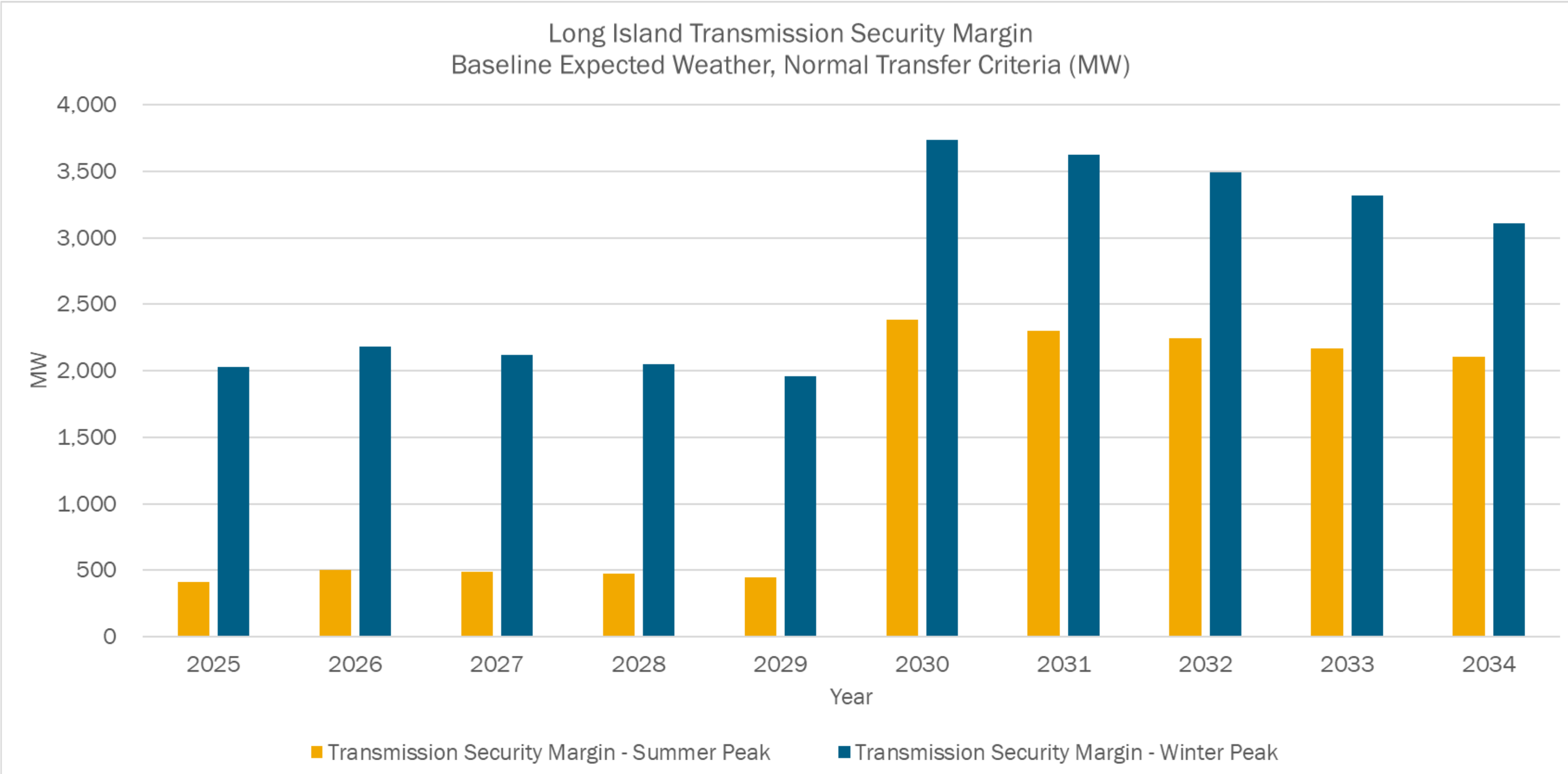
Figure 62: Winter Peak Long Island Margin Calculation

Winter Peak - Baseline Expected Weather, Normal Transfer Criteria (MW)											
Line	Item	2025-26	2026-27	2027-28	2028-29	2029-30	2030-31	2031-32	2032-33	2033-34	2034-35
A	**Zone K Demand Forecast (4)**	(3,299)	(3,334)	(3,396)	(3,465)	(3,553)	(3,639)	(3,750)	(3,880)	(4,058)	(4,266)
B	I+J to K (3)	900	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	0
D	**Total K AC Import (B+C)**	900	900	900	900	900	2,500	2,500	2,500	2,500	2,500
E	Loss of Source Contingency	(660)	(660)	(660)	(660)	(660)	(400)	(400)	(400)	(400)	(400)
F	**Resource Need (A+D+E)**	(3,059)	(3,094)	(3,156)	(3,225)	(3,313)	(1,539)	(1,650)	(1,780)	(1,958)	(2,166)
G	K Generation (1)	5,505	6,429	6,429	6,429	6,429	6,383	6,383	6,383	6,383	6,383
H	K Generation Derates (2)	(634)	(1,374)	(1,374)	(1,374)	(1,374)	(1,374)	(1,374)	(1,374)	(1,374)	(1,374)
I	Shortage of Gas Fuel Supply (5)	(441)	(441)	(441)	(441)	(441)	(395)	(395)	(395)	(395)	(395)
J	Temperature Based Generation Derates	0	0	0	0	0	0	0	0	0	0
K	Net ICAP External Imports	660	660	660	660	660	660	660	660	660	660
L	**Total Resources Available (G+H+I+J+K)**	5,090	5,275	5,275	5,275	5,275	5,275	5,275	5,275	5,275	5,275
M	**Transmission Security Margin (F+L)**	2,031	2,181	2,119	2,050	1,962	3,736	3,625	3,495	3,317	3,109

Notes:

1. Reflects the 2024 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 10% 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 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 August 2023 (https://www.nerc.com/pa/RAPA/gads/Pages/Reports.aspx).
3. Limits for 2025-26 are based on the summer peak 2025 representations evaluated in the post-2020 RNA updates (as a conservative winter peak assumption these limits utilize the summer values). Limits for 2026-27 through 2029-30 are based on winter peak 2029-30 representations evaluated in the 2024 RNA. Limits for 2030-31 through 2034-35 are based on the winter peak 2034-35 representations evaluated in the 2024 RNA.
4. Reflects the 2024 Gold Book Forecast.
5. 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.

Figure 63: Long Island Margin Chart – Summer and Winter



Appendix F – Additional Outage Impacts to Margins

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

- **Figure 64**: AOI - Statewide System Margin
- **Figure 65**: AOI - Lower Hudson Valley Transmission Security Margin
- **Figure 66**: AOI - New York City Transmission Security Margin
- **Figure 67**: AOI - Long Island Transmission Security Margin

Figure 64: AOI - Statewide System Margin

Additional Outage Impacts - Statewide System Margin													
			Year	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Statewide System Margin Summer Peak - High Demand Forecast Expected Summer Weather, Normal Transfer Criteria (MW) (1)				(97)	523	54	(459)	(930)	(1,451)	(2,439)	(3,101)	(3,792)	(4,462)
Unit Name	Summer DMNC (MW)	NERC 5-Year Class Average De-Rate (MW)	Summer De-Rated Capability (MW)	Transmission Security Margin Considering Outage of Generator/Plant (Retire, Mothball, or IIFO)									
Jamestown 5, 6 & 7	80.8	(8.48)	72.32	(170)	451	(18)	(531)	(1,002)	(1,523)	(2,512)	(3,173)	(3,864)	(4,534)
Jamestown 5	21.9	(2.30)	19.60	(117)	504	34	(478)	(949)	(1,471)	(2,459)	(3,120)	(3,811)	(4,481)
Jamestown 6	19.1	(2.01)	17.09	(115)	506	37	(476)	(947)	(1,468)	(2,456)	(3,118)	(3,809)	(4,479)
Jamestown 7	39.8	(4.18)	35.62	(133)	488	18	(494)	(965)	(1,487)	(2,475)	(3,136)	(3,827)	(4,497)
Indeck-Yerkes	43.8	(1.94)	41.86	(139)	482	12	(500)	(972)	(1,493)	(2,481)	(3,142)	(3,834)	(4,504)
Indeck-Olean	77.5	(3.43)	74.07	(171)	449	(20)	(533)	(1,004)	(1,525)	(2,513)	(3,175)	(3,866)	(4,536)
American Ref-Fuel 1 & 2	37.6	(3.95)	33.65	(131)	490	20	(492)	(963)	(1,485)	(2,473)	(3,134)	(3,825)	(4,495)
American Ref-Fuel 1	18.8	(1.97)	16.83	(114)	507	37	(475)	(947)	(1,468)	(2,456)	(3,117)	(3,809)	(4,479)
American Ref-Fuel 2	18.8	(1.97)	16.83	(114)	507	37	(475)	(947)	(1,468)	(2,456)	(3,117)	(3,809)	(4,479)
Fortistar - N.Tonawanda (BTM:NG)	53.3	(2.36)	50.94	(148)	472	3	(510)	(981)	(1,502)	(2,490)	(3,151)	(3,843)	(4,513)
Model City Energy	5.6	(0.71)	4.89	(102)	519	49	(463)	(935)	(1,456)	(2,444)	(3,105)	(3,797)	(4,467)
Modern LF	6.4	(0.81)	5.59	(103)	518	48	(464)	(935)	(1,457)	(2,445)	(3,106)	(3,797)	(4,467)
Chaffee	6.4	(0.81)	5.59	(103)	518	48	(464)	(935)	(1,457)	(2,445)	(3,106)	(3,797)	(4,467)
Chautauqua LFGE	0.0	0.00	0.00	(97)	523	54	(459)	(930)	(1,451)	(2,439)	(3,101)	(3,792)	(4,462)
Lockport CC1, CC2, and CC3	208.8	(9.25)	199.55	(297)	324	(146)	(658)	(1,129)	(1,651)	(2,639)	(3,300)	(3,991)	(4,661)
Lockport CC1	69.6	(3.08)	66.52	(164)	457	(13)	(525)	(996)	(1,517)	(2,506)	(3,167)	(3,858)	(4,528)
Lockport CC2	69.6	(3.08)	66.52	(164)	457	(13)	(525)	(996)	(1,517)	(2,506)	(3,167)	(3,858)	(4,528)
Lockport CC3	69.6	(3.08)	66.52	(164)	457	(13)	(525)	(996)	(1,517)	(2,506)	(3,167)	(3,858)	(4,528)
Allegany	62.8	(2.78)	60.02	(157)	463	(6)	(519)	(990)	(1,511)	(2,499)	(3,161)	(3,852)	(4,522)
R. E. Ginna	581.5	(10.99)	570.51	(668)	(47)	(517)	(1,029)	(1,500)	(2,021)	(3,010)	(3,671)	(4,362)	(5,032)
Batavia	47.7	(2.11)	45.59	(143)	478	8	(504)	(975)	(1,497)	(2,485)	(3,146)	(3,837)	(4,507)
Nine Mile Point 2	1,274.7	(27.53)	1,247.17	(1,085)	(465)	(934)	(1,447)	(1,918)	(2,439)	(3,427)	(4,089)	(4,780)	(5,450)
Mill Seat	6.4	(0.81)	5.59	(103)	518	48	(464)	(935)	(1,457)	(2,445)	(3,106)	(3,797)	(4,467)
Hyland LFGE	4.8	(0.60)	4.20	(102)	519	50	(463)	(934)	(1,455)	(2,444)	(3,105)	(3,796)	(4,466)
Synergy Biogas	0.0	0.00	0.00	(97)	523	54	(459)	(930)	(1,451)	(2,439)	(3,101)	(3,792)	(4,462)
Red Rochester (BTM:NG)	13.3	(1.40)	11.90	(109)	512	42	(470)	(942)	(1,463)	(2,451)	(3,112)	(3,804)	(4,474)
James A. FitzPatrick	852.8	(18.42)	834.38	(932)	(311)	(781)	(1,293)	(1,764)	(2,285)	(3,274)	(3,935)	(4,626)	(5,296)
Oswego 6	803.0	(84.32)	718.69	(816)	(195)	(665)	(1,177)	(1,648)	(2,170)	(3,158)	(3,819)	(4,510)	(5,180)
Oswego 5	809.5	(85.00)	724.50	(822)	(201)	(671)	(1,183)	(1,654)	(2,175)	(3,164)	(3,825)	(4,516)	(5,186)
Nine Mile Point 1	621.4	(13.42)	607.98	(705)	(85)	(554)	(1,067)	(1,538)	(2,059)	(3,047)	(3,709)	(4,400)	(5,070)
Independence GS1, GS2, GS3, & GS4	980.4	(43.43)	936.97	(1,034)	(414)	(883)	(1,396)	(1,867)	(2,388)	(3,376)	(4,038)	(4,729)	(5,399)
Independence GS1	245.1	(10.86)	234.24	(332)	289	(180)	(693)	(1,164)	(1,685)	(2,674)	(3,335)	(4,026)	(4,696)
Independence GS2	245.1	(10.86)	234.24	(332)	289	(180)	(693)	(1,164)	(1,685)	(2,674)	(3,335)	(4,026)	(4,696)
Independence GS3	245.1	(10.86)	234.24	(332)	289	(180)	(693)	(1,164)	(1,685)	(2,674)	(3,335)	(4,026)	(4,696)
Independence GS4	245.1	(10.86)	234.24	(332)	289	(180)	(693)	(1,164)	(1,685)	(2,674)	(3,335)	(4,026)	(4,696)
Syracuse	83.2	(3.69)	79.51	(177)	444	(26)	(538)	(1,009)	(1,530)	(2,519)	(3,180)	(3,871)	(4,541)
Carr St.-E. Syr	89.8	(3.98)	85.82	(183)	438	(32)	(544)	(1,016)	(1,537)	(2,525)	(3,186)	(3,878)	(4,548)
Indeck-Oswego	51.8	(2.29)	49.51	(147)	474	4	(508)	(979)	(1,500)	(2,489)	(3,150)	(3,841)	(4,511)
Indeck-Silver Springs	51.4	(2.28)	49.12	(147)	474	5	(508)	(979)	(1,500)	(2,488)	(3,150)	(3,841)	(4,511)
Greenidge 4 (BTM:NG)	25.9	(2.72)	23.18	(121)	(1,047)	169	(36)	(240)	(494)	(834)	(1,328)	(1,823)	(2,393)
Ontario LFGE	11.2	(1.41)	9.79	(107)	514	44	(468)	(940)	(1,461)	(2,449)	(3,110)	(3,802)	(4,472)
High Acres	9.6	(1.21)	8.39	(106)	515	45	(467)	(938)	(1,459)	(2,448)	(3,109)	(3,800)	(4,470)
Seneca Energy 1 & 2	17.6	(2.22)	15.38	(113)	508	38	(474)	(945)	(1,466)	(2,455)	(3,116)	(3,807)	(4,477)
Seneca Energy 1	8.8	(1.11)	7.69	(105)	516	46	(466)	(937)	(1,459)	(2,447)	(3,108)	(3,799)	(4,469)
Seneca Energy 2	8.8	(1.11)	7.69	(105)	516	46	(466)	(937)	(1,459)	(2,447)	(3,108)	(3,799)	(4,469)
Broome LFGE	2.4	(0.30)	2.10	(100)	521	52	(461)	(932)	(1,453)	(2,441)	(3,103)	(3,794)	(4,464)
Massena	79.5	(3.52)	75.98	(173)	447	(22)	(535)	(1,006)	(1,527)	(2,515)	(3,177)	(3,868)	(4,538)
Clinton LFGE	6.4	(0.81)	5.59	(103)	518	48	(464)	(935)	(1,457)	(2,445)	(3,106)	(3,797)	(4,467)
Saranac Energy CC1 & CC2	237.9	(10.54)	227.36	(325)	296	(174)	(686)	(1,157)	(1,678)	(2,667)	(3,328)	(4,019)	(4,689)
Saranac Energy CC1	121.8	(5.40)	116.40	(214)	407	(63)	(575)	(1,046)	(1,567)	(2,556)	(3,217)	(3,908)	(4,578)
Saranac Energy CC2	116.1	(5.14)	110.96	(208)	412	(57)	(570)	(1,041)	(1,562)	(2,550)	(3,212)	(3,903)	(4,573)
Sterling	49.7	(2.20)	47.50	(145)	476	6	(506)	(977)	(1,498)	(2,487)	(3,148)	(3,839)	(4,509)
Carthage Energy	56.4	(2.50)	53.90	(151)	470	(0)	(512)	(984)	(1,505)	(2,493)	(3,154)	(3,846)	(4,516)
Beaver Falls	78.1	(3.46)	74.64	(172)	449	(21)	(533)	(1,004)	(1,526)	(2,514)	(3,175)	(3,866)	(4,536)
Broome 2 LFGE	2.1	(0.26)	1.84	(99)	522	52	(460)	(932)	(1,453)	(2,441)	(3,102)	(3,794)	(4,464)
DANC LFGE	6.4	(0.81)	5.59	(103)	518	48	(464)	(935)	(1,457)	(2,445)	(3,106)	(3,797)	(4,467)
Oneida-Herkimer LFGE	3.2	(0.40)	2.80	(100)	521	51	(461)	(933)	(1,454)	(2,442)	(3,103)	(3,795)	(4,465)
Athens 1, 2, and 3	993.8	(44.03)	949.77	(1,047)	(426)	(896)	(1,408)	(1,880)	(2,401)	(3,389)	(4,050)	(4,742)	(5,412)
Athens 1	329.4	(14.59)	314.81	(412)	209	(261)	(773)	(1,245)	(1,766)	(2,754)	(3,415)	(4,107)	(4,777)
Athens 2	333.3	(14.77)	318.53	(416)	205	(265)	(777)	(1,248)	(1,769)	(2,758)	(3,419)	(4,110)	(4,780)
Athens 3	331.1	(14.67)	316.43	(414)	207	(263)	(775)	(1,246)	(1,767)	(2,756)	(3,417)	(4,108)	(4,778)
Rensselaer	76.3	(3.38)	72.92	(170)	450	(19)	(531)	(1,003)	(1,524)	(2,512)	(3,173)	(3,865)	(4,535)
Wheelabrator Hudson Falls	10.4	(1.09)	9.31	(107)	514	45	(468)	(939)	(1,460)	(2,449)	(3,110)	(3,801)	(4,471)

Additional Outage Impacts - Statewide System Margin													
			Year	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Statewide System Margin Summer Peak - High Demand Forecast Expected Summer Weather, Normal Transfer Criteria (MW) (1)				(97)	523	54	(459)	(930)	(1,451)	(2,439)	(3,101)	(3,792)	(4,462)
Unit Name	Summer DMNC (MW)	NERC 5-Year Class Average De-Rate (MW)	Summer De-Rated Capability (MW)	Transmission Security Margin Considering Outage of Generator/Plant (Retire, Mothball, or IIFO)									
Selkirk I & II	353.3	(15.65)	337.65	(435)	186	(284)	(796)	(1,267)	(1,789)	(2,777)	(3,438)	(4,129)	(4,799)
Selkirk-I	76.1	(3.37)	72.73	(170)	451	(19)	(531)	(1,002)	(1,524)	(2,512)	(3,173)	(3,864)	(4,534)
Selkirk-II	277.2	(12.28)	264.92	(362)	258	(211)	(723)	(1,195)	(1,716)	(2,704)	(3,365)	(4,057)	(4,727)
Indeck-Corinth	131.1	(5.81)	125.29	(223)	398	(71)	(584)	(1,055)	(1,576)	(2,565)	(3,226)	(3,917)	(4,587)
Castleton Energy Center	67.9	(3.01)	64.89	(162)	459	(11)	(523)	(995)	(1,516)	(2,504)	(3,165)	(3,857)	(4,527)
Bethlehem GS1, GS2, GS3	818.4	(36.26)	782.14	(880)	(259)	(728)	(1,241)	(1,712)	(2,233)	(3,221)	(3,883)	(4,574)	(5,244)
Bethlehem GS1	272.8	(12.09)	260.71	(358)	263	(207)	(719)	(1,190)	(1,712)	(2,700)	(3,361)	(4,052)	(4,722)
Bethlehem GS2	272.8	(12.09)	260.71	(358)	263	(207)	(719)	(1,190)	(1,712)	(2,700)	(3,361)	(4,052)	(4,722)
Bethlehem GS3	272.8	(12.09)	260.71	(358)	263	(207)	(719)	(1,190)	(1,712)	(2,700)	(3,361)	(4,052)	(4,722)
Colonie LFGTE	6.4	(0.81)	5.59	(103)	518	48	(464)	(935)	(1,457)	(2,445)	(3,106)	(3,797)	(4,467)
Albany LFGE	5.6	(0.71)	4.89	(102)	519	49	(463)	(935)	(1,456)	(2,444)	(3,105)	(3,797)	(4,467)
Fulton LFGE	3.2	(0.40)	2.80	(100)	521	51	(461)	(933)	(1,454)	(2,442)	(3,103)	(3,795)	(4,465)
Empire CC1 & CC2	587.4	(26.02)	561.38	(659)	(38)	(508)	(1,020)	(1,491)	(2,012)	(3,001)	(3,662)	(4,353)	(5,023)
Empire CC1	293.7	(13.01)	280.69	(378)	243	(227)	(739)	(1,210)	(1,732)	(2,720)	(3,381)	(4,072)	(4,742)
Empire CC2	293.7	(13.01)	280.69	(378)	243	(227)	(739)	(1,210)	(1,732)	(2,720)	(3,381)	(4,072)	(4,742)
Bowline 1 & 2	1,143.0	(120.02)	1,022.99	(1,120)	(500)	(969)	(1,482)	(1,953)	(2,474)	(3,462)	(4,124)	(4,815)	(5,485)
Bowline 1	577.8	(60.67)	517.13	(615)	6	(463)	(976)	(1,447)	(1,968)	(2,956)	(3,618)	(4,309)	(4,979)
Bowline 2	565.2	(59.35)	505.85	(603)	18	(452)	(964)	(1,436)	(1,957)	(2,945)	(3,606)	(4,298)	(4,968)
Danskammer 1, 2, 3, & 4	499.4	(52.44)	446.96	(544)	76	(393)	(906)	(1,377)	(1,898)	(2,886)	(3,548)	(4,239)	(4,909)
Danskammer 1	68.5	(7.19)	61.31	(159)	462	(7)	(520)	(991)	(1,512)	(2,501)	(3,162)	(3,853)	(4,523)
Danskammer 2	65.0	(6.83)	58.18	(156)	465	(4)	(517)	(988)	(1,509)	(2,498)	(3,159)	(3,850)	(4,520)
Danskammer 3	140.1	(14.71)	125.39	(223)	398	(72)	(584)	(1,055)	(1,576)	(2,565)	(3,226)	(3,917)	(4,587)
Danskammer 4	225.8	(23.71)	202.09	(299)	321	(148)	(661)	(1,132)	(1,653)	(2,641)	(3,303)	(3,994)	(4,664)
Roseton 1 & 2	1,228.2	(128.96)	1,099.24	(1,197)	(576)	(1,045)	(1,558)	(2,029)	(2,550)	(3,539)	(4,200)	(4,891)	(5,561)
Roseton 1	615.7	(64.65)	551.05	(648)	(28)	(497)	(1,010)	(1,481)	(2,002)	(2,990)	(3,652)	(4,343)	(5,013)
Roseton 2	612.5	(64.31)	548.19	(646)	(25)	(494)	(1,007)	(1,478)	(1,999)	(2,988)	(3,649)	(4,340)	(5,010)
Hillburn GT	36.0	(3.31)	32.69	(130)	491	21	(491)	(962)	(1,484)	(2,472)	(3,133)	(3,824)	(4,494)
Shoemaker GT	35.4	(3.25)	32.15	(130)	491	22	(491)	(962)	(1,483)	(2,471)	(3,133)	(3,824)	(4,494)
DCRRA	6.2	(0.65)	5.55	(103)	518	48	(464)	(935)	(1,457)	(2,445)	(3,106)	(3,797)	(4,467)
CPV Valley CC1 & CC2	645.4	(28.59)	616.81	(714)	(93)	(563)	(1,075)	(1,547)	(2,068)	(3,056)	(3,717)	(4,409)	(5,079)
CPV Valley CC1	322.7	(14.30)	308.40	(406)	215	(255)	(767)	(1,238)	(1,759)	(2,748)	(3,409)	(4,100)	(4,770)
CPV Valley CC2	322.7	(14.30)	308.40	(406)	215	(255)	(767)	(1,238)	(1,759)	(2,748)	(3,409)	(4,100)	(4,770)
Cricket Valley CC1, CC2, & CC3	1,050.8	(46.55)	1,004.25	(1,102)	(481)	(950)	(1,463)	(1,934)	(2,455)	(3,444)	(4,105)	(4,796)	(5,466)
Cricket Valley CC1	347.1	(15.38)	331.72	(429)	192	(278)	(790)	(1,261)	(1,783)	(2,771)	(3,432)	(4,123)	(4,793)
Cricket Valley CC2	345.0	(15.28)	329.72	(427)	194	(276)	(788)	(1,259)	(1,781)	(2,769)	(3,430)	(4,121)	(4,791)
Cricket Valley CC3	358.7	(15.89)	342.81	(440)	181	(289)	(801)	(1,273)	(1,794)	(2,782)	(3,443)	(4,135)	(4,805)
Wheelabrator Westchester	52.5	(5.51)	46.99	(144)	476	7	(506)	(977)	(1,498)	(2,486)	(3,148)	(3,839)	(4,509)
Arthur Kill ST 2 & 3	884.9	(92.91)	791.99	(889)	(269)	(738)	(1,251)	(1,722)	(2,243)	(3,231)	(3,893)	(4,584)	(5,254)
Arthur Kill ST 2	362.2	(38.03)	324.17	(422)	199	(270)	(783)	(1,254)	(1,775)	(2,764)	(3,425)	(4,116)	(4,786)
Arthur Kill ST 3	522.7	(54.88)	467.82	(565)	56	(414)	(926)	(1,398)	(1,919)	(2,907)	(3,568)	(4,260)	(4,930)
Brooklyn Navy Yard	247.5	(10.96)	236.54	(334)	287	(183)	(695)	(1,166)	(1,687)	(2,676)	(3,337)	(4,028)	(4,698)
Astoria 2, 3, & 5	916.9	(96.27)	820.63	(918)	(297)	(767)	(1,279)	(1,750)	(2,272)	(3,260)	(3,921)	(4,612)	(5,282)
Astoria 2	171.2	(17.98)	153.22	(251)	370	(99)	(612)	(1,083)	(1,604)	(2,593)	(3,254)	(3,945)	(4,615)
Astoria 3	372.4	(39.10)	333.30	(431)	190	(279)	(792)	(1,263)	(1,784)	(2,773)	(3,434)	(4,125)	(4,795)
Astoria 5	373.3	(39.20)	334.10	(432)	189	(280)	(793)	(1,264)	(1,785)	(2,773)	(3,435)	(4,126)	(4,796)
Ravenswood ST 01, 02, & 03	1,958.2	(191.73)	1,766.47	(1,864)	(1,243)	(1,713)	(2,225)	(2,696)	(3,217)	(4,206)	(4,867)	(5,558)	(6,228)
Ravenswood ST 01	367.0	(38.54)	328.47	(426)	195	(275)	(787)	(1,258)	(1,779)	(2,768)	(3,429)	(4,120)	(4,790)
Ravenswood ST 02	375.3	(39.41)	335.89	(433)	188	(282)	(794)	(1,266)	(1,787)	(2,775)	(3,436)	(4,128)	(4,798)
Ravenswood ST 03	987.3	(103.67)	883.63	(981)	(360)	(830)	(1,342)	(1,813)	(2,335)	(3,323)	(3,984)	(4,675)	(5,345)
Ravenswood CC 04	228.6	(10.13)	218.47	(316)	305	(165)	(677)	(1,148)	(1,669)	(2,658)	(3,319)	(4,010)	(4,680)
East River 1, 2, 6, & 7	620.5	(46.55)	573.95	(671)	(51)	(520)	(1,033)	(1,504)	(2,025)	(3,013)	(3,674)	(4,366)	(5,036)
East River 1	151.5	(6.71)	144.79	(242)	379	(91)	(603)	(1,075)	(1,596)	(2,584)	(3,245)	(3,937)	(4,607)
East River 2	155.0	(6.87)	148.13	(246)	375	(94)	(607)	(1,078)	(1,599)	(2,587)	(3,249)	(3,940)	(4,610)
East River 6	131.6	(13.82)	117.78	(215)	406	(64)	(576)	(1,048)	(1,569)	(2,557)	(3,218)	(3,910)	(4,580)
East River 7	182.4	(19.15)	163.25	(261)	360	(109)	(622)	(1,093)	(1,614)	(2,603)	(3,264)	(3,955)	(4,625)
Linden Cogen	737.1	(32.65)	704.45	(802)	(181)	(651)	(1,163)	(1,634)	(2,155)	(3,144)	(3,805)	(4,496)	(5,166)
KIAC_JFK (BTM:NG)	106.4	(4.71)	101.69	(199)	422	(48)	(560)	(1,031)	(1,553)	(2,541)	(3,202)	(3,893)	(4,563)
Gowanus 5 & 6	79.9	(8.39)	71.51	(169)	452	(18)	(530)	(1,001)	(1,522)	(2,511)	(3,172)	(3,863)	(4,533)
Gowanus 5	40.0	(4.20)	35.80	(133)	488	18	(494)	(966)	(1,487)	(2,475)	(3,136)	(3,828)	(4,498)
Gowanus 6	39.9	(4.19)	35.71	(133)	488	18	(494)	(965)	(1,487)	(2,475)	(3,136)	(3,827)	(4,497)
Kent	46.0	(4.83)	41.17	(139)	482	13	(500)	(971)	(1,492)	(2,481)	(3,142)	(3,833)	(4,503)
Pouch	45.4	(4.77)	40.63	(138)	483	13	(499)	(970)	(1,492)	(2,480)	(3,141)	(3,832)	(4,502)

Additional Outage Impacts - Statewide System Margin													
			Year	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Statewide System Margin Summer Peak - High Demand Forecast Expected Summer Weather, Normal Transfer Criteria (MW) (1)				(97)	523	54	(459)	(930)	(1,451)	(2,439)	(3,101)	(3,792)	(4,462)
Unit Name	Summer DMNC (MW)	NERC 5-Year Class Average De-Rate (MW)	Summer De-Rated Capability (MW)	Transmission Security Margin Considering Outage of Generator/Plant (Retire, Mothball, or IIFO)									
Hellgate 1 & 2	79.5	(8.35)	71.15	(169)	452	(17)	(530)	(1,001)	(1,522)	(2,511)	(3,172)	(3,863)	(4,533)
Hellgate 1	39.9	(4.19)	35.71	(133)	488	18	(494)	(965)	(1,487)	(2,475)	(3,136)	(3,827)	(4,497)
Hellgate 2	39.6	(4.16)	35.44	(133)	488	18	(494)	(965)	(1,486)	(2,475)	(3,136)	(3,827)	(4,497)
Harlem River 1 & 2	79.5	(8.35)	71.15	(169)	452	(17)	(530)	(1,001)	(1,522)	(2,511)	(3,172)	(3,863)	(4,533)
Harlem River 1	39.9	(4.19)	35.71	(133)	488	18	(494)	(965)	(1,487)	(2,475)	(3,136)	(3,827)	(4,497)
Harlem River 2	39.6	(4.16)	35.44	(133)	488	18	(494)	(965)	(1,486)	(2,475)	(3,136)	(3,827)	(4,497)
Vernon Blvd 2 & 3	79.9	(8.39)	71.51	(169)	452	(18)	(530)	(1,001)	(1,522)	(2,511)	(3,172)	(3,863)	(4,533)
Vernon Blvd 2	40.0	(4.20)	35.80	(133)	488	18	(494)	(966)	(1,487)	(2,475)	(3,136)	(3,828)	(4,498)
Vernon Blvd 3	39.9	(4.19)	35.71	(133)	488	18	(494)	(965)	(1,487)	(2,475)	(3,136)	(3,827)	(4,497)
Astoria CC 1 & 2	474.0	(21.00)	453.00	(550)	70	(399)	(912)	(1,383)	(1,904)	(2,892)	(3,554)	(4,245)	(4,915)
Astoria CC 1	237.0	(10.50)	226.50	(324)	297	(173)	(685)	(1,156)	(1,677)	(2,666)	(3,327)	(4,018)	(4,688)
Astoria CC 2	237.0	(10.50)	226.50	(324)	297	(173)	(685)	(1,156)	(1,677)	(2,666)	(3,327)	(4,018)	(4,688)
Astoria East Energy CC1 & CC2	579.2	(25.66)	553.54	(651)	(30)	(500)	(1,012)	(1,483)	(2,005)	(2,993)	(3,654)	(4,345)	(5,015)
Astoria East Energy - CC1	289.6	(12.83)	276.77	(374)	247	(223)	(735)	(1,207)	(1,728)	(2,716)	(3,377)	(4,069)	(4,739)
Astoria East Energy - CC2	289.6	(12.83)	276.77	(374)	247	(223)	(735)	(1,207)	(1,728)	(2,716)	(3,377)	(4,069)	(4,739)
Astoria Energy 2 - CC3 & CC4	570.6	(25.28)	545.32	(643)	(22)	(492)	(1,004)	(1,475)	(1,996)	(2,985)	(3,646)	(4,337)	(5,007)
Astoria Energy 2 - CC3	285.3	(12.64)	272.66	(370)	251	(219)	(731)	(1,202)	(1,724)	(2,712)	(3,373)	(4,064)	(4,734)
Astoria Energy 2 - CC4	285.3	(12.64)	272.66	(370)	251	(219)	(731)	(1,202)	(1,724)	(2,712)	(3,373)	(4,064)	(4,734)
Bayonne EC CT G1 through G10	598.6	(55.01)	543.59	(641)	(20)	(490)	(1,002)	(1,473)	(1,995)	(2,983)	(3,644)	(4,335)	(5,005)
Bayonne EC CTG1	62.0	(5.70)	56.30	(154)	467	(2)	(515)	(986)	(1,507)	(2,496)	(3,157)	(3,848)	(4,518)
Bayonne EC CTG2	58.0	(5.33)	52.67	(150)	471	1	(511)	(982)	(1,504)	(2,492)	(3,153)	(3,844)	(4,514)
Bayonne EC CTG3	58.0	(5.33)	52.67	(150)	471	1	(511)	(982)	(1,504)	(2,492)	(3,153)	(3,844)	(4,514)
Bayonne EC CTG4	61.1	(5.62)	55.48	(153)	468	(2)	(514)	(985)	(1,506)	(2,495)	(3,156)	(3,847)	(4,517)
Bayonne EC CTG5	58.5	(5.38)	53.12	(151)	470	1	(512)	(983)	(1,504)	(2,492)	(3,154)	(3,845)	(4,515)
Bayonne EC CTG6	59.0	(5.42)	53.58	(151)	470	0	(512)	(983)	(1,505)	(2,493)	(3,154)	(3,845)	(4,515)
Bayonne EC CTG7	59.3	(5.45)	53.85	(151)	470	(0)	(512)	(984)	(1,505)	(2,493)	(3,154)	(3,846)	(4,516)
Bayonne EC CTG8	60.0	(5.51)	54.49	(152)	469	(1)	(513)	(984)	(1,505)	(2,494)	(3,155)	(3,846)	(4,516)
Bayonne EC CTG9	61.3	(5.63)	55.67	(153)	468	(2)	(514)	(985)	(1,507)	(2,495)	(3,156)	(3,847)	(4,517)
Bayonne EC CTG10	61.4	(5.64)	55.76	(153)	468	(2)	(514)	(986)	(1,507)	(2,495)	(3,156)	(3,847)	(4,517)
Greenport IC 4, 5, & 6	5.6	(0.80)	4.80	(102)	519	49	(463)	(935)	(1,456)	(2,444)	(3,105)	(3,797)	(4,467)
Greenport IC 4	1.0	(0.14)	0.86	(98)	523	53	(459)	(931)	(1,452)	(2,440)	(3,101)	(3,793)	(4,463)
Greenport IC 5	1.5	(0.21)	1.29	(99)	522	53	(460)	(931)	(1,452)	(2,441)	(3,102)	(3,793)	(4,463)
Greenport IC 6	3.1	(0.44)	2.66	(100)	521	51	(461)	(932)	(1,454)	(2,442)	(3,103)	(3,794)	(4,464)
Freeport 1-2, 1-3, & 2-3	21.1	(2.42)	18.68	(116)	505	35	(477)	(948)	(1,470)	(2,458)	(3,119)	(3,810)	(4,480)
Freeport 1-2	2.5	(0.36)	2.14	(100)	521	52	(461)	(932)	(1,453)	(2,441)	(3,103)	(3,794)	(4,464)
Freeport 1-3	2.9	(0.42)	2.48	(100)	521	51	(461)	(932)	(1,453)	(2,442)	(3,103)	(3,794)	(4,464)
Freeport 2-3	15.7	(1.65)	14.05	(111)	509	40	(473)	(944)	(1,465)	(2,453)	(3,115)	(3,806)	(4,476)
Charles P Killer 09 through 14	16.0	(1.50)	14.50	(112)	509	39	(473)	(944)	(1,465)	(2,454)	(3,115)	(3,806)	(4,476)
Charles P Keller 09	1.9	(0.18)	1.72	(99)	522	52	(460)	(931)	(1,453)	(2,441)	(3,102)	(3,793)	(4,463)
Charles P Keller 10	1.9	(0.18)	1.72	(99)	522	52	(460)	(931)	(1,453)	(2,441)	(3,102)	(3,793)	(4,463)
Charles P Keller 11	2.8	(0.26)	2.54	(100)	521	51	(461)	(932)	(1,453)	(2,442)	(3,103)	(3,794)	(4,464)
Charles P Keller 12	3.0	(0.28)	2.72	(100)	521	51	(461)	(932)	(1,454)	(2,442)	(3,103)	(3,794)	(4,464)
Charles P Keller 13	3.0	(0.28)	2.72	(100)	521	51	(461)	(932)	(1,454)	(2,442)	(3,103)	(3,794)	(4,464)
Charles P Keller 14	3.4	(0.32)	3.08	(100)	520	51	(462)	(933)	(1,454)	(2,442)	(3,104)	(3,795)	(4,465)
Wading River 1, 2, & 3	231.4	(24.30)	207.10	(305)	316	(153)	(666)	(1,137)	(1,658)	(2,646)	(3,308)	(3,999)	(4,669)
Wading River 1	79.7	(8.37)	71.33	(169)	452	(18)	(530)	(1,001)	(1,522)	(2,511)	(3,172)	(3,863)	(4,533)
Wading River 2	76.4	(8.02)	68.38	(166)	455	(15)	(527)	(998)	(1,519)	(2,508)	(3,169)	(3,860)	(4,530)
Wading River 3	75.3	(7.91)	67.39	(165)	456	(14)	(526)	(997)	(1,518)	(2,507)	(3,168)	(3,859)	(4,529)
Barrett ST 01 & 02	383.0	(40.22)	342.79	(440)	181	(289)	(801)	(1,273)	(1,794)	(2,782)	(3,443)	(4,135)	(4,805)
Barrett ST 01	195.0	(20.48)	174.53	(272)	349	(121)	(633)	(1,104)	(1,625)	(2,614)	(3,275)	(3,966)	(4,636)
Barrett ST 02	188.0	(19.74)	168.26	(266)	355	(114)	(627)	(1,098)	(1,619)	(2,608)	(3,269)	(3,960)	(4,630)
Barrett GT 01 through 12	246.2	(23.90)	222.30	(320)	301	(168)	(681)	(1,152)	(1,673)	(2,662)	(3,323)	(4,014)	(4,684)
Barrett GT 01	14.0	(1.47)	12.53	(110)	511	41	(471)	(942)	(1,463)	(2,452)	(3,113)	(3,804)	(4,474)
Barrett GT 02	13.6	(1.43)	12.17	(110)	511	42	(471)	(942)	(1,463)	(2,452)	(3,113)	(3,804)	(4,474)
Barrett 03	13.7	(1.44)	12.26	(110)	511	42	(471)	(942)	(1,463)	(2,452)	(3,113)	(3,804)	(4,474)
Barrett 04	15.8	(1.66)	14.14	(112)	509	40	(473)	(944)	(1,465)	(2,453)	(3,115)	(3,806)	(4,476)
Barrett 05	13.5	(1.42)	12.08	(109)	511	42	(471)	(942)	(1,463)	(2,451)	(3,113)	(3,804)	(4,474)
Barrett 06	14.1	(1.48)	12.62	(110)	511	41	(471)	(942)	(1,464)	(2,452)	(3,113)	(3,804)	(4,474)
Barrett 08	12.3	(1.29)	11.01	(108)	512	43	(470)	(941)	(1,462)	(2,450)	(3,112)	(3,803)	(4,473)
Barrett 09	31.2	(2.87)	28.33	(126)	495	25	(487)	(958)	(1,479)	(2,468)	(3,129)	(3,820)	(4,490)
Barrett 10	39.6	(3.64)	35.96	(133)	487	18	(495)	(966)	(1,487)	(2,475)	(3,137)	(3,828)	(4,498)
Barrett 11	39.0	(3.58)	35.42	(133)	488	18	(494)	(965)	(1,486)	(2,475)	(3,136)	(3,827)	(4,497)
Barrett 12	39.4	(3.62)	35.78	(133)	488	18	(494)	(966)	(1,487)	(2,475)	(3,136)	(3,828)	(4,498)

Additional Outage Impacts - Statewide System Margin													
			Year	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Statewide System Margin Summer Peak - High Demand Forecast Expected Summer Weather, Normal Transfer Criteria (MW) (1)				(97)	523	54	(459)	(930)	(1,451)	(2,439)	(3,101)	(3,792)	(4,462)
Unit Name	Summer DMNC (MW)	NERC 5-Year Class Average De-Rate (MW)	Summer De-Rated Capability (MW)	Transmission Security Margin Considering Outage of Generator/Plant (Retire, Mothball, or IIFO)									
Northport 1, 2, 3, and 4	1,553.9	(163.16)	1,390.74	(1,488)	(867)	(1,337)	(1,849)	(2,321)	(2,842)	(3,830)	(4,491)	(5,182)	(5,852)
Northport 1	398.0	(41.79)	356.21	(454)	167	(302)	(815)	(1,286)	(1,807)	(2,796)	(3,457)	(4,148)	(4,818)
Northport 2	399.4	(41.94)	357.46	(455)	166	(304)	(816)	(1,287)	(1,808)	(2,797)	(3,458)	(4,149)	(4,819)
Northport 3	388.5	(40.79)	347.71	(445)	176	(294)	(806)	(1,277)	(1,799)	(2,787)	(3,448)	(4,139)	(4,809)
Northport 4	368.0	(38.64)	329.36	(427)	194	(276)	(788)	(1,259)	(1,780)	(2,769)	(3,430)	(4,121)	(4,791)
Port Jefferson GT 02 & 03	80.6	(8.46)	72.14	(170)	451	(18)	(531)	(1,002)	(1,523)	(2,511)	(3,173)	(3,864)	(4,534)
Port Jefferson GT 02	40.6	(4.26)	36.34	(134)	487	17	(495)	(966)	(1,487)	(2,476)	(3,137)	(3,828)	(4,498)
Port Jefferson GT 03	40.0	(4.20)	35.80	(133)	488	18	(494)	(966)	(1,487)	(2,475)	(3,136)	(3,828)	(4,498)
Port Jefferson 3 & 4	383.7	(40.29)	343.41	(441)	180	(290)	(802)	(1,273)	(1,794)	(2,783)	(3,444)	(4,135)	(4,805)
Port Jefferson 3	189.7	(19.92)	169.78	(267)	354	(116)	(628)	(1,100)	(1,621)	(2,609)	(3,270)	(3,962)	(4,632)
Port Jefferson 4	194.0	(20.37)	173.63	(271)	350	(120)	(632)	(1,103)	(1,625)	(2,613)	(3,274)	(3,965)	(4,635)
Hempstead (RR)	74.8	(7.85)	66.95	(164)	456	(13)	(526)	(997)	(1,518)	(2,506)	(3,167)	(3,859)	(4,529)
Glenwood GT 02, 04, & 05	146.7	(15.40)	131.30	(229)	392	(77)	(590)	(1,061)	(1,582)	(2,571)	(3,232)	(3,923)	(4,593)
Glenwood GT 02	59.3	(6.23)	53.07	(150)	470	1	(512)	(983)	(1,504)	(2,492)	(3,154)	(3,845)	(4,515)
Glenwood GT 04	43.3	(4.55)	38.75	(136)	485	15	(497)	(969)	(1,490)	(2,478)	(3,139)	(3,830)	(4,500)
Glenwood GT 05	44.1	(4.63)	39.47	(137)	484	14	(498)	(969)	(1,490)	(2,479)	(3,140)	(3,831)	(4,501)
Holtsville 01 through 10	525.3	(48.28)	477.02	(574)	46	(423)	(936)	(1,407)	(1,928)	(2,916)	(3,578)	(4,269)	(4,939)
Holtsville 01	55.0	(5.05)	49.95	(147)	473	4	(509)	(980)	(1,501)	(2,489)	(3,150)	(3,842)	(4,512)
Holtsville 02	57.0	(5.24)	51.76	(149)	472	2	(510)	(982)	(1,503)	(2,491)	(3,152)	(3,844)	(4,514)
Holtsville 03	51.1	(4.70)	46.40	(144)	477	7	(505)	(976)	(1,497)	(2,486)	(3,147)	(3,838)	(4,508)
Holtsville 04	54.3	(4.99)	49.31	(147)	474	5	(508)	(979)	(1,500)	(2,489)	(3,150)	(3,841)	(4,511)
Holtsville 05	53.4	(4.91)	48.49	(146)	475	5	(507)	(978)	(1,499)	(2,488)	(3,149)	(3,840)	(4,510)
Holtsville 06	49.1	(4.51)	44.59	(142)	479	9	(503)	(974)	(1,496)	(2,484)	(3,145)	(3,836)	(4,506)
Holtsville 07	53.0	(4.87)	48.13	(146)	475	6	(507)	(978)	(1,499)	(2,487)	(3,149)	(3,840)	(4,510)
Holtsville 08	52.1	(4.79)	47.31	(145)	476	7	(506)	(977)	(1,498)	(2,487)	(3,148)	(3,839)	(4,509)
Holtsville 09	54.2	(4.98)	49.22	(147)	474	5	(508)	(979)	(1,500)	(2,489)	(3,150)	(3,841)	(4,511)
Holtsville 10	46.1	(4.24)	41.86	(139)	482	12	(500)	(972)	(1,493)	(2,481)	(3,142)	(3,834)	(4,504)
Shoreham GT 3 & 4	83.3	(8.75)	74.55	(172)	449	(21)	(533)	(1,004)	(1,526)	(2,514)	(3,175)	(3,866)	(4,536)
Shoreham GT3	42.1	(4.42)	37.68	(135)	486	16	(496)	(967)	(1,489)	(2,477)	(3,138)	(3,829)	(4,499)
Shoreham GT4	41.2	(4.33)	36.87	(134)	487	17	(495)	(967)	(1,488)	(2,476)	(3,137)	(3,829)	(4,499)
East Hampton GT 01, 2, 3, & 4	24.2	(2.53)	21.67	(119)	502	32	(480)	(951)	(1,473)	(2,461)	(3,122)	(3,813)	(4,483)
East Hampton GT 01	18.2	(1.67)	16.53	(114)	507	37	(475)	(946)	(1,467)	(2,456)	(3,117)	(3,808)	(4,478)
East Hampton 2	2.0	(0.29)	1.71	(99)	522	52	(460)	(931)	(1,453)	(2,441)	(3,102)	(3,793)	(4,463)
East Hampton 3	2.0	(0.29)	1.71	(99)	522	52	(460)	(931)	(1,453)	(2,441)	(3,102)	(3,793)	(4,463)
East Hampton 4	2.0	(0.29)	1.71	(99)	522	52	(460)	(931)	(1,453)	(2,441)	(3,102)	(3,793)	(4,463)
Southold 1	9.4	(0.99)	8.41	(106)	515	45	(467)	(938)	(1,459)	(2,448)	(3,109)	(3,800)	(4,470)
S Hampton 1	7.8	(0.82)	6.98	(104)	516	47	(466)	(937)	(1,458)	(2,446)	(3,108)	(3,799)	(4,469)
Freeport CT 1 & 2	88.9	(9.33)	79.57	(177)	444	(26)	(538)	(1,009)	(1,531)	(2,519)	(3,180)	(3,871)	(4,541)
Freeport CT 1	45.9	(4.82)	41.08	(138)	482	13	(500)	(971)	(1,492)	(2,480)	(3,142)	(3,833)	(4,503)
Freeport CT 2	43.0	(4.52)	38.49	(136)	485	15	(497)	(968)	(1,489)	(2,478)	(3,139)	(3,830)	(4,500)
Flynn	139.5	(6.18)	133.32	(231)	390	(80)	(592)	(1,063)	(1,584)	(2,573)	(3,234)	(3,925)	(4,595)
Greenport GT1	51.2	(4.71)	46.49	(144)	477	7	(505)	(976)	(1,497)	(2,486)	(3,147)	(3,838)	(4,508)
Far Rockaway GT1 & GT2	104.6	(9.61)	94.99	(192)	428	(41)	(554)	(1,025)	(1,546)	(2,534)	(3,196)	(3,887)	(4,557)
Far Rockaway GT1	48.9	(4.49)	44.41	(142)	479	9	(503)	(974)	(1,495)	(2,484)	(3,145)	(3,836)	(4,506)
Far Rockaway GT2	55.7	(5.12)	50.58	(148)	473	3	(509)	(980)	(1,502)	(2,490)	(3,151)	(3,842)	(4,512)
Bethpage	52.0	(2.30)	49.70	(147)	474	4	(508)	(979)	(1,501)	(2,489)	(3,150)	(3,841)	(4,511)
Bethpage 3	76.0	(3.37)	72.63	(170)	451	(19)	(531)	(1,002)	(1,524)	(2,512)	(3,173)	(3,864)	(4,534)
Bethpage GT4	43.6	(4.58)	39.02	(136)	484	15	(498)	(969)	(1,490)	(2,478)	(3,140)	(3,831)	(4,501)
Stony Brook (BTM:NG)	0.0	0.00	0.00	(97)	523	54	(459)	(930)	(1,451)	(2,439)	(3,101)	(3,792)	(4,462)
Brentwood	45.0	(4.73)	40.28	(138)	483	14	(499)	(970)	(1,491)	(2,480)	(3,141)	(3,832)	(4,502)
Pilgrim GT1 & GT2	83.8	(8.80)	75.00	(172)	448	(21)	(534)	(1,005)	(1,526)	(2,514)	(3,176)	(3,867)	(4,537)
Pilgrim GT1	41.9	(4.40)	37.50	(135)	486	16	(496)	(967)	(1,488)	(2,477)	(3,138)	(3,829)	(4,499)
Pilgrim GT2	41.9	(4.40)	37.50	(135)	486	16	(496)	(967)	(1,488)	(2,477)	(3,138)	(3,829)	(4,499)
Pinelawn Power 1	73.4	(3.25)	70.15	(168)	453	(16)	(529)	(1,000)	(1,521)	(2,510)	(3,171)	(3,862)	(4,532)
Caithness_CC_1	306.9	(13.60)	293.30	(391)	230	(239)	(752)	(1,223)	(1,744)	(2,733)	(3,394)	(4,085)	(4,755)
Islip (RR)	8.5	(0.89)	7.61	(105)	516	46	(466)	(937)	(1,459)	(2,447)	(3,108)	(3,799)	(4,469)
Babylon (RR)	15.6	(1.64)	13.96	(111)	509	40	(473)	(944)	(1,465)	(2,453)	(3,115)	(3,806)	(4,476)
Huntington (RR)	24.7	(2.59)	22.11	(120)	501	32	(481)	(952)	(1,473)	(2,461)	(3,123)	(3,814)	(4,484)

Notes

1. Utilizes the Higher Demand Statewide System Margin for Summer Peak with Expected Weather.
2. Utilizes the next largest generation contingency outage which is the loss of the Cricket Valley CC1, CC2, & CC3.

Figure 65: AOI - Lower Hudson Valley Transmission Security Margin

Additional Outage Impacts - Lower Hudson Valley													
			Year	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Lower Hudson Valley Transmission Security Margin, Summer Peak - High Demand Forecast Expected Summer Weather, Normal Transfer Criteria (MW) (1)				1,193	2,256	2,107	1,959	1,749	1,456	762	436	81	(267)
Unit Name	Summer DMNC (MW)	NERC 5-Year Class Average De-Rate (MW)	Summer De-Rated Capability (MW)	Transmission Security Margin Considering Outage of Generator/Plant (Retire, Mothball, or IIFO)									
Bowline 1 & 2	1,143.0	(120.02)	1,022.99	170	1,233	1,084	936	726	433	(261)	(587)	(942)	(1,290)
Bowline 1	577.8	(60.67)	517.13	676	1,739	1,590	1,442	1,232	939	245	(81)	(436)	(784)
Bowline 2	565.2	(59.35)	505.85	687	1,750	1,601	1,453	1,243	950	256	(70)	(425)	(773)
Danskammer 1, 2, 3, & 4	499.4	(52.44)	446.96	746	1,809	1,660	1,512	1,302	1,009	315	(11)	(366)	(714)
Danskammer 1	68.5	(7.19)	61.31	1,132	2,195	2,046	1,898	1,688	1,395	701	374	20	(329)
Danskammer 2	65.0	(6.83)	58.18	1,135	2,198	2,049	1,901	1,691	1,398	704	378	23	(325)
Danskammer 3	140.1	(14.71)	125.39	1,068	2,131	1,982	1,833	1,623	1,331	636	310	(44)	(393)
Danskammer 4	225.8	(23.71)	202.09	991	2,054	1,905	1,757	1,547	1,254	560	234	(121)	(469)
Roseton 1 & 2	1,228.2	(128.96)	1,099.24	94	1,157	1,008	860	650	357	(337)	(663)	(1,018)	(1,366)
Roseton 1	615.7	(64.65)	551.05	642	1,705	1,556	1,408	1,198	905	211	(115)	(470)	(818)
Roseton 2	612.5	(64.31)	548.19	645	1,708	1,559	1,411	1,201	908	214	(112)	(467)	(815)
Hillburn GT	36.0	(3.31)	32.69	1,160	2,224	2,074	1,926	1,716	1,423	729	403	49	(300)
Shoemaker GT	35.4	(3.25)	32.15	1,161	2,224	2,075	1,927	1,717	1,424	730	404	49	(299)
DCRRA	6.2	(0.65)	5.55	1,188	2,251	2,101	1,953	1,743	1,451	756	430	76	(273)
CPV Valley CC1 & CC2	645.4	(28.59)	616.81	576	1,640	1,490	1,342	1,132	839	145	(181)	(536)	(884)
CPV Valley CC1	322.7	(14.30)	308.40	885	1,948	1,799	1,650	1,440	1,148	453	127	(227)	(576)
CPV Valley CC2	322.7	(14.30)	308.40	885	1,948	1,799	1,650	1,440	1,148	453	127	(227)	(576)
Cricket Valley CC1, CC2, & CC3	1,050.8	(46.55)	1,004.25	189	1,252	1,103	955	745	452	(242)	(568)	(923)	(1,271)
Cricket Valley CC1	347.1	(15.38)	331.72	861	1,925	1,775	1,627	1,417	1,124	430	104	(250)	(599)
Cricket Valley CC2	345.0	(15.28)	329.72	863	1,927	1,777	1,629	1,419	1,126	432	106	(248)	(597)
Cricket Valley CC3	358.7	(15.89)	342.81	850	1,914	1,764	1,616	1,406	1,113	419	93	(262)	(610)
Wheelabrator Westchester	52.5	(5.51)	46.99	1,146	2,209	2,060	1,912	1,702	1,409	715	389	34	(314)
Arthur Kill ST 2 & 3	884.9	(92.91)	791.99	401	1,464	1,315	1,167	957	664	(30)	(356)	(711)	(1,059)
Arthur Kill ST 2	362.2	(38.03)	324.17	869	1,932	1,783	1,635	1,425	1,132	438	112	(243)	(591)
Arthur Kill ST 3	522.7	(54.88)	467.82	725	1,789	1,639	1,491	1,281	988	294	(32)	(387)	(735)
Brooklyn Navy Yard	247.5	(10.96)	236.54	957	2,020	1,870	1,722	1,512	1,220	525	199	(155)	(504)
Astoria 2, 3, & 5	916.9	(96.27)	820.63	372	1,436	1,286	1,138	928	635	(59)	(385)	(739)	(1,088)
Astoria 2	171.2	(17.98)	153.22	1,040	2,103	1,954	1,806	1,596	1,303	609	283	(72)	(420)
Astoria 3	372.4	(39.10)	333.30	860	1,923	1,774	1,626	1,416	1,123	429	103	(252)	(601)
Astoria 5	373.3	(39.20)	334.10	859	1,922	1,773	1,625	1,415	1,122	428	102	(253)	(601)
Ravenswood ST 01, 02, & 03	1,729.6	(181.61)	1,547.99	(68)	708	559	411	201	(92)	(786)	(1,112)	(1,467)	(1,815)
Ravenswood ST 01	367.0	(38.54)	328.47	865	1,928	1,778	1,630	1,420	1,128	433	107	(247)	(596)
Ravenswood ST 02	375.3	(39.41)	335.89	857	1,920	1,771	1,623	1,413	1,120	426	100	(255)	(603)
Ravenswood ST 03	987.3	(103.67)	883.63	597	1,373	1,223	1,075	865	572	(122)	(448)	(802)	(1,151)
Ravenswood CC 04	228.6	(10.13)	218.47	975	2,038	1,888	1,740	1,530	1,238	543	217	(137)	(486)
East River 1, 2, 6, & 7	620.5	(46.55)	573.95	619	1,682	1,533	1,385	1,175	882	188	(138)	(493)	(841)
East River 1	151.5	(6.71)	144.79	1,048	2,112	1,962	1,814	1,604	1,311	617	291	(64)	(412)
East River 2	155.0	(6.87)	148.13	1,045	2,108	1,959	1,811	1,601	1,308	614	288	(67)	(415)
East River 6	131.6	(13.82)	117.78	1,075	2,139	1,989	1,841	1,631	1,338	644	318	(37)	(385)
East River 7	182.4	(19.15)	163.25	1,030	2,093	1,944	1,796	1,586	1,293	599	273	(82)	(430)
Linden Cogen	737.1	(32.65)	704.45	489	1,552	1,402	1,254	1,044	752	57	(269)	(623)	(972)
KIAC_JFK (BTM:NG)	106.4	(4.71)	101.69	1,091	2,155	2,005	1,857	1,647	1,354	660	334	(20)	(369)
Gowanus 5 & 6	79.9	(8.39)	71.51	1,122	2,185	2,035	1,887	1,677	1,385	690	364	10	(339)
Gowanus 5	40.0	(4.20)	35.80	1,157	2,221	2,071	1,923	1,713	1,420	726	400	45	(303)
Gowanus 6	39.9	(4.19)	35.71	1,157	2,221	2,071	1,923	1,713	1,420	726	400	46	(303)
Kent	46.0	(4.83)	41.17	1,152	2,215	2,066	1,918	1,708	1,415	721	395	40	(308)
Pouch	45.4	(4.77)	40.63	1,152	2,216	2,066	1,918	1,708	1,415	721	395	41	(308)
Hellgate 1 & 2	79.5	(8.35)	71.15	1,122	2,185	2,036	1,888	1,678	1,385	691	365	10	(338)
Hellgate 1	39.9	(4.19)	35.71	1,157	2,221	2,071	1,923	1,713	1,420	726	400	46	(303)
Hellgate 2	39.6	(4.16)	35.44	1,158	2,221	2,071	1,923	1,713	1,421	726	400	46	(303)
Harlem River 1 & 2	79.5	(8.35)	71.15	1,122	2,185	2,036	1,888	1,678	1,385	691	365	10	(338)
Harlem River 1	39.9	(4.19)	35.71	1,157	2,221	2,071	1,923	1,713	1,420	726	400	46	(303)
Harlem River 2	39.6	(4.16)	35.44	1,158	2,221	2,071	1,923	1,713	1,421	726	400	46	(303)
Vernon Blvd 2 & 3	79.9	(8.39)	71.51	1,122	2,185	2,035	1,887	1,677	1,385	690	364	10	(339)
Vernon Blvd 2	40.0	(4.20)	35.80	1,157	2,221	2,071	1,923	1,713	1,420	726	400	45	(303)
Vernon Blvd 3	39.9	(4.19)	35.71	1,157	2,221	2,071	1,923	1,713	1,420	726	400	46	(303)
Astoria CC 1 & 2	474.0	(21.00)	453.00	740	1,803	1,654	1,506	1,296	1,003	309	(17)	(372)	(720)
Astoria CC 1	237.0	(10.50)	226.50	967	2,030	1,880	1,732	1,522	1,230	535	209	(145)	(494)
Astoria CC 2	237.0	(10.50)	226.50	967	2,030	1,880	1,732	1,522	1,230	535	209	(145)	(494)
Astoria East Energy CC1 & CC2	579.2	(25.66)	553.54	640	1,703	1,553	1,405	1,195	903	208	(118)	(472)	(821)
Astoria East Energy - CC1	289.6	(12.83)	276.77	916	1,980	1,830	1,682	1,472	1,179	485	159	(196)	(544)
Astoria East Energy - CC2	289.6	(12.83)	276.77	916	1,980	1,830	1,682	1,472	1,179	485	159	(196)	(544)

Additional Outage Impacts - Lower Hudson Valley													
			Year	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Lower Hudson Valley Transmission Security Margin, Summer Peak - High Demand Forecast Expected Summer Weather, Normal Transfer Criteria (MW) (1)				1,193	2,256	2,107	1,959	1,749	1,456	762	436	81	(267)
Unit Name	Summer DMNC (MW)	NERC 5-Year Class Average De-Rate (MW)	Summer De-Rated Capability (MW)	Transmission Security Margin Considering Outage of Generator/Plant (Retire, Mothball, or IIFO)									
Astoria Energy 2 - CC3 & CC4	570.6	(25.28)	545.32	648	1,711	1,562	1,413	1,203	911	217	(110)	(464)	(813)
Astoria Energy 2 - CC3	285.3	(12.64)	272.66	920	1,984	1,834	1,686	1,476	1,183	489	163	(191)	(540)
Astoria Energy 2 - CC4	285.3	(12.64)	272.66	920	1,984	1,834	1,686	1,476	1,183	489	163	(191)	(540)
Bayonne EC CT G1 through G10	598.6	(55.01)	543.59	650	1,713	1,563	1,415	1,205	913	218	(108)	(462)	(811)
Bayonne EC CTG1	62.0	(5.70)	56.30	1,137	2,200	2,051	1,903	1,693	1,400	706	380	25	(324)
Bayonne EC CTG2	58.0	(5.33)	52.67	1,140	2,204	2,054	1,906	1,696	1,403	709	383	29	(320)
Bayonne EC CTG3	58.0	(5.33)	52.67	1,140	2,204	2,054	1,906	1,696	1,403	709	383	29	(320)
Bayonne EC CTG4	61.1	(5.62)	55.48	1,138	2,201	2,051	1,903	1,693	1,401	706	380	26	(323)
Bayonne EC CTG5	58.5	(5.38)	53.12	1,140	2,203	2,054	1,906	1,696	1,403	709	383	28	(320)
Bayonne EC CTG6	59.0	(5.42)	53.58	1,140	2,203	2,053	1,905	1,695	1,403	708	382	28	(321)
Bayonne EC CTG7	59.3	(5.45)	53.85	1,139	2,202	2,053	1,905	1,695	1,402	708	382	27	(321)
Bayonne EC CTG8	60.0	(5.51)	54.49	1,139	2,202	2,052	1,904	1,694	1,402	707	381	27	(322)
Bayonne EC CTG9	61.3	(5.63)	55.67	1,137	2,201	2,051	1,903	1,693	1,400	706	380	26	(323)
Bayonne EC CTG10	61.4	(5.64)	55.76	1,137	2,201	2,051	1,903	1,693	1,400	706	380	26	(323)

Notes

1. Utilizes the High Demand Transmission Security Margin for Summer Peak with Expected Weather.
2. In 2025 the most limiting contingency combination includes the loss of Ravenswood 3. For this calculation the margin based on the loss of two transmission elements is utilized. Other combinations with loss of generation may be more limiting.

Figure 66: AOI - New York City Transmission Security Margin

Additional Outage Impacts - New York City													
			Year	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
New York City Transmission Security Margin, Summer Peak - High Demand Forecast Expected Summer Weather, Normal Transfer Criteria (MW) (1)				(461)	209	160	30	(100)	(140)	(647)	(807)	(967)	(1,137)
Unit Name	Summer DMNC (MW)	NERC 5-Year Class Average De-Rate (MW)	Summer De-Rated Capability (MW)	Transmission Security Margin Considering Outage of Generator/Plant (Retire, Mothball, or IIFO)									
Arthur Kill ST 2 & 3	884.9	(92.91)	791.99	(1,253)	(583)	(632)	(762)	(892)	(932)	(1,439)	(1,599)	(1,759)	(1,929)
Arthur Kill ST 2	362.2	(38.03)	324.17	(785)	(115)	(164)	(294)	(424)	(464)	(971)	(1,131)	(1,291)	(1,461)
Arthur Kill ST 3	522.7	(54.88)	467.82	(929)	(259)	(308)	(438)	(568)	(608)	(1,115)	(1,275)	(1,435)	(1,605)
Brooklyn Navy Yard	247.5	(10.96)	236.54	(698)	(28)	(76)	(206)	(336)	(376)	(883)	(1,043)	(1,203)	(1,373)
Astoria 2, 3, & 5	916.9	(96.27)	820.63	(1,282)	(612)	(660)	(790)	(920)	(960)	(1,468)	(1,628)	(1,788)	(1,958)
Astoria 2	171.2	(17.98)	153.22	(615)	55	7	(123)	(253)	(293)	(800)	(960)	(1,120)	(1,290)
Astoria 3	372.4	(39.10)	333.30	(795)	(125)	(173)	(303)	(433)	(473)	(980)	(1,140)	(1,300)	(1,470)
Astoria 5	373.3	(39.20)	334.10	(795)	(125)	(174)	(304)	(434)	(474)	(981)	(1,141)	(1,301)	(1,471)
Ravenswood ST 01, 02, & 03 (2)	1,729.6	(181.61)	1,547.99	(1,822)	(1,152)	(1,200)	(1,330)	(1,460)	(1,500)	(2,008)	(2,168)	(2,328)	(2,498)
Ravenswood ST 01	367.0	(38.54)	328.47	(790)	(120)	(168)	(298)	(428)	(468)	(975)	(1,135)	(1,295)	(1,465)
Ravenswood ST 02	375.3	(39.41)	335.89	(797)	(127)	(176)	(306)	(436)	(476)	(983)	(1,143)	(1,303)	(1,473)
Ravenswood ST 03 (2)	987.3	(103.67)	883.63	(1,158)	(488)	(156)	(666)	(796)	(836)	(1,343)	(1,503)	(1,663)	(1,833)
Ravenswood CC 04	228.6	(10.13)	218.47	(680)	(10)	(58)	(188)	(318)	(358)	(865)	(1,025)	(1,185)	(1,355)
East River 1, 2, 6, & 7	620.5	(46.55)	573.95	(1,035)	(365)	(414)	(544)	(674)	(714)	(1,221)	(1,381)	(1,541)	(1,711)
East River 1	151.5	(6.71)	144.79	(606)	64	16	(114)	(244)	(284)	(792)	(952)	(1,112)	(1,282)
East River 2	155.0	(6.87)	148.13	(609)	61	12	(118)	(248)	(288)	(795)	(955)	(1,115)	(1,285)
East River 6	131.6	(13.82)	117.78	(579)	91	43	(87)	(217)	(257)	(765)	(925)	(1,085)	(1,255)
East River 7	182.4	(19.15)	163.25	(625)	45	(3)	(133)	(263)	(303)	(810)	(970)	(1,130)	(1,300)
Linden Cogen	737.1	(32.65)	704.45	(1,166)	(496)	(544)	(674)	(804)	(844)	(1,351)	(1,511)	(1,671)	(1,841)
KIAC_JFK (BTM:NG)	106.4	(4.71)	101.69	(563)	107	59	(71)	(201)	(241)	(749)	(909)	(1,069)	(1,239)
Gowanus 5 & 6	79.9	(8.39)	71.51	(533)	137	89	(41)	(171)	(211)	(718)	(878)	(1,038)	(1,208)
Gowanus 5	40.0	(4.20)	35.80	(497)	173	124	(6)	(136)	(176)	(683)	(843)	(1,003)	(1,173)
Gowanus 6	39.9	(4.19)	35.71	(497)	173	125	(5)	(135)	(175)	(683)	(843)	(1,003)	(1,173)
Kent	46.0	(4.83)	41.17	(502)	168	119	(11)	(141)	(181)	(688)	(848)	(1,008)	(1,178)
Pouch	45.4	(4.77)	40.63	(502)	168	120	(10)	(140)	(180)	(688)	(848)	(1,008)	(1,178)
Hellgate 1 & 2	79.5	(8.35)	71.15	(532)	138	89	(41)	(171)	(211)	(718)	(878)	(1,038)	(1,208)
Hellgate 1	39.9	(4.19)	35.71	(497)	173	125	(5)	(135)	(175)	(683)	(843)	(1,003)	(1,173)
Hellgate 2	39.6	(4.16)	35.44	(497)	173	125	(5)	(135)	(175)	(682)	(842)	(1,002)	(1,172)
Harlem River 1 & 2	79.5	(8.35)	71.15	(532)	138	89	(41)	(171)	(211)	(718)	(878)	(1,038)	(1,208)
Harlem River 1	39.9	(4.19)	35.71	(497)	173	125	(5)	(135)	(175)	(683)	(843)	(1,003)	(1,173)
Harlem River 2	39.6	(4.16)	35.44	(497)	173	125	(5)	(135)	(175)	(682)	(842)	(1,002)	(1,172)
Vernon Blvd 2 & 3	79.9	(8.39)	71.51	(533)	137	89	(41)	(171)	(211)	(718)	(878)	(1,038)	(1,208)
Vernon Blvd 2	40.0	(4.20)	35.80	(497)	173	124	(6)	(136)	(176)	(683)	(843)	(1,003)	(1,173)
Vernon Blvd 3	39.9	(4.19)	35.71	(497)	173	125	(5)	(135)	(175)	(683)	(843)	(1,003)	(1,173)
Astoria CC 1 & 2	474.0	(21.00)	453.00	(914)	(244)	(293)	(423)	(553)	(593)	(1,100)	(1,260)	(1,420)	(1,590)
Astoria CC 1	237.0	(10.50)	226.50	(688)	(18)	(66)	(196)	(326)	(366)	(873)	(1,033)	(1,193)	(1,363)
Astoria CC 2	237.0	(10.50)	226.50	(688)	(18)	(66)	(196)	(326)	(366)	(873)	(1,033)	(1,193)	(1,363)
Astoria East Energy CC1 & CC2	579.2	(25.66)	553.54	(1,015)	(345)	(393)	(523)	(653)	(693)	(1,200)	(1,360)	(1,520)	(1,690)
Astoria East Energy - CC1	289.6	(12.83)	276.77	(738)	(68)	(116)	(246)	(376)	(416)	(924)	(1,084)	(1,244)	(1,414)
Astoria East Energy - CC2	289.6	(12.83)	276.77	(738)	(68)	(116)	(246)	(376)	(416)	(924)	(1,084)	(1,244)	(1,414)
Astoria Energy 2 - CC3 & CC4	570.6	(25.28)	545.32	(1,007)	(337)	(385)	(515)	(645)	(685)	(1,192)	(1,352)	(1,512)	(1,682)
Astoria Energy 2 - CC3	285.3	(12.64)	272.66	(734)	(64)	(112)	(242)	(372)	(412)	(920)	(1,080)	(1,240)	(1,410)
Astoria Energy 2 - CC4	285.3	(12.64)	272.66	(734)	(64)	(112)	(242)	(372)	(412)	(920)	(1,080)	(1,240)	(1,410)
Bayonne EC CT G1 through G10	598.6	(55.01)	543.59	(1,005)	(335)	(383)	(513)	(643)	(683)	(1,190)	(1,350)	(1,510)	(1,680)
Bayonne EC CTG1	62.0	(5.70)	56.30	(518)	152	104	(26)	(156)	(196)	(703)	(863)	(1,023)	(1,193)
Bayonne EC CTG2	58.0	(5.33)	52.67	(514)	156	108	(22)	(152)	(192)	(700)	(860)	(1,020)	(1,190)
Bayonne EC CTG3	58.0	(5.33)	52.67	(514)	156	108	(22)	(152)	(192)	(700)	(860)	(1,020)	(1,190)
Bayonne EC CTG4	61.1	(5.62)	55.48	(517)	153	105	(25)	(155)	(195)	(702)	(862)	(1,022)	(1,192)
Bayonne EC CTG5	58.5	(5.38)	53.12	(514)	156	107	(23)	(153)	(193)	(700)	(860)	(1,020)	(1,190)
Bayonne EC CTG6	59.0	(5.42)	53.58	(515)	155	107	(23)	(153)	(193)	(700)	(860)	(1,020)	(1,190)
Bayonne EC CTG7	59.3	(5.45)	53.85	(515)	155	106	(24)	(154)	(194)	(701)	(861)	(1,021)	(1,191)
Bayonne EC CTG8	60.0	(5.51)	54.49	(516)	154	106	(24)	(154)	(194)	(701)	(861)	(1,021)	(1,191)
Bayonne EC CTG9	61.3	(5.63)	55.67	(517)	153	105	(25)	(155)	(195)	(703)	(863)	(1,023)	(1,193)
Bayonne EC CTG10	61.4	(5.64)	55.76	(517)	153	105	(25)	(155)	(195)	(703)	(863)	(1,023)	(1,193)

Notes

1. Utilizes the Higher Demand Transmission Security Margin for Summer Peak with Expected Weather.
2. In all years the most limiting contingency includes the loss of Ravenswood 3. For this calculation the margin based on the loss of two transmission elements is utilized. Other combinations with loss of generation may be more limiting.

Figure 67: AOI - Long Island Transmission Security Margin

Additional Outage Impacts - Long Island													
			Year	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Long Island Transmission Security Margin, Summer Peak - High Demand Forecast Expected Summer Weather, Normal Transfer Criteria (MW) (1)				368	437	409	372	326	2,228	2,113	2,024	1,923	1,821
Unit Name	Summer DMNC (MW)	NERC 5-Year Class Average De-Rate (MW)	Summer De-Rated Capability (MW)	Transmission Security Margin Considering Outage of Generator/Plant (Retire, Mothball, or IIFO)									
Greenport IC 4, 5, & 6	5.6	(0.80)	4.80	363	432	404	368	321	2,223	2,108	2,019	1,918	1,816
Greenport IC 4	1.0	(0.14)	0.86	367	436	408	372	325	2,227	2,112	2,023	1,922	1,820
Greenport IC 5	1.5	(0.21)	1.29	366	436	408	371	325	2,226	2,112	2,022	1,922	1,820
Greenport IC 6	3.1	(0.44)	2.66	365	434	406	370	323	2,225	2,111	2,021	1,920	1,818
Freeport 1-2, 1-3, & 2-3	21.1	(2.42)	18.68	349	418	390	354	307	2,209	2,095	2,005	1,904	1,802
Freeport 1-2	2.5	(0.36)	2.14	366	435	407	370	324	2,226	2,111	2,022	1,921	1,819
Freeport 1-3	2.9	(0.42)	2.48	365	435	406	370	323	2,225	2,111	2,021	1,921	1,819
Freeport 2-3	15.7	(1.65)	14.05	354	423	395	358	312	2,214	2,099	2,010	1,909	1,807
Charles P Killer 09 through 14	16.0	(1.50)	14.50	353	423	394	358	311	2,213	2,099	2,009	1,909	1,807
Charles P Keller 09	1.9	(0.18)	1.72	366	435	407	371	324	2,226	2,112	2,022	1,921	1,819
Charles P Keller 10	1.9	(0.18)	1.72	366	435	407	371	324	2,226	2,112	2,022	1,921	1,819
Charles P Keller 11	2.8	(0.26)	2.54	365	434	406	370	323	2,225	2,111	2,021	1,921	1,819
Charles P Keller 12	3.0	(0.28)	2.72	365	434	406	370	323	2,225	2,111	2,021	1,920	1,818
Charles P Keller 13	3.0	(0.28)	2.72	365	434	406	370	323	2,225	2,111	2,021	1,920	1,818
Charles P Keller 14	3.4	(0.32)	3.08	365	434	406	369	323	2,225	2,110	2,021	1,920	1,818
Wading River 1, 2, & 3	231.4	(24.30)	207.10	161	230	202	165	119	2,021	1,906	1,817	1,716	1,614
Wading River 1	79.7	(8.37)	71.33	296	366	338	301	255	2,156	2,042	1,952	1,852	1,750
Wading River 2	76.4	(8.02)	68.38	299	369	341	304	257	2,159	2,045	1,955	1,855	1,753
Wading River 3	75.3	(7.91)	67.39	300	370	342	305	258	2,160	2,046	1,956	1,856	1,754
Barrett ST 01 & 02	383.0	(40.22)	342.79	25	94	66	30	(17)	1,885	1,770	1,681	1,580	1,478
Barrett ST 01	195.0	(20.48)	174.53	193	263	234	198	151	2,053	1,939	1,849	1,749	1,647
Barrett ST 02	188.0	(19.74)	168.26	199	269	241	204	158	2,060	1,945	1,855	1,755	1,653
Barrett GT 01 through 12	246.2	(23.90)	222.30	145	215	187	150	104	2,005	1,891	1,801	1,701	1,599
Barrett GT 01	14.0	(1.47)	12.53	355	425	396	360	313	2,215	2,101	2,011	1,911	1,809
Barrett GT 02	13.6	(1.43)	12.17	356	425	397	360	314	2,216	2,101	2,012	1,911	1,809
Barrett 03	13.7	(1.44)	12.26	355	425	397	360	314	2,216	2,101	2,011	1,911	1,809
Barrett 04	15.8	(1.66)	14.14	354	423	395	358	312	2,214	2,099	2,010	1,909	1,807
Barrett 05	13.5	(1.42)	12.08	356	425	397	360	314	2,216	2,101	2,012	1,911	1,809
Barrett 06	14.1	(1.48)	12.62	355	424	396	360	313	2,215	2,101	2,011	1,911	1,809
Barrett 08	12.3	(1.29)	11.01	357	426	398	361	315	2,217	2,102	2,013	1,912	1,810
Barrett 09	31.2	(2.87)	28.33	339	409	381	344	298	2,199	2,085	1,995	1,895	1,793
Barrett 10	39.6	(3.64)	35.96	332	401	373	336	290	2,192	2,077	1,988	1,887	1,785
Barrett 11	39.0	(3.58)	35.42	332	402	374	337	290	2,192	2,078	1,988	1,888	1,786
Barrett 12	39.4	(3.62)	35.78	332	401	373	337	290	2,192	2,077	1,988	1,887	1,785
Northport 1, 2, 3, and 4	1,553.9	(163.16)	1,390.74	(1,023)	(954)	(982)	(1,018)	(1,065)	837	722	633	532	430
Northport 1	398.0	(41.79)	356.21	12	81	53	16	(30)	1,872	1,757	1,667	1,567	1,465
Northport 2	399.4	(41.94)	357.46	10	80	51	15	(32)	1,870	1,756	1,666	1,566	1,464
Northport 3	388.5	(40.79)	347.71	20	89	61	25	(22)	1,880	1,766	1,676	1,575	1,473
Northport 4	368.0	(38.64)	329.36	38	108	80	43	(4)	1,898	1,784	1,694	1,594	1,492
Port Jefferson GT 02 & 03	80.6	(8.46)	72.14	296	365	337	300	254	2,156	2,041	1,952	1,851	1,749
Port Jefferson GT 02	40.6	(4.26)	36.34	331	401	373	336	290	2,191	2,077	1,987	1,887	1,785
Port Jefferson GT 03	40.0	(4.20)	35.80	332	401	373	337	290	2,192	2,077	1,988	1,887	1,785
Port Jefferson 3 & 4	383.7	(40.29)	343.41	24	94	66	29	(18)	1,884	1,770	1,680	1,580	1,478
Port Jefferson 3	189.7	(19.92)	169.78	198	267	239	203	156	2,058	1,943	1,854	1,753	1,651
Port Jefferson 4	194.0	(20.37)	173.63	194	263	235	199	152	2,054	1,940	1,850	1,750	1,648
Hempstead (RR)	74.8	(7.85)	66.95	301	370	342	305	259	2,161	2,046	1,957	1,856	1,754
Glenwood GT 02, 04, & 05	146.7	(15.40)	131.30	236	306	278	241	195	2,096	1,982	1,892	1,792	1,690
Glenwood GT 02	59.3	(6.23)	53.07	315	384	356	319	273	2,175	2,060	1,971	1,870	1,768
Glenwood GT 04	43.3	(4.55)	38.75	329	398	370	334	287	2,189	2,074	1,985	1,884	1,782
Glenwood GT 05	44.1	(4.63)	39.47	328	398	369	333	286	2,188	2,074	1,984	1,884	1,782
Holtsville 01 through 10	525.3	(48.28)	477.02	(109)	(40)	(68)	(105)	(151)	1,751	1,636	1,547	1,446	1,344
Holtsville 01	55.0	(5.05)	49.95	318	387	359	322	276	2,178	2,063	1,974	1,873	1,771
Holtsville 02	57.0	(5.24)	51.76	316	385	357	321	274	2,176	2,061	1,972	1,871	1,769
Holtsville 03	51.1	(4.70)	46.40	321	391	363	326	279	2,181	2,067	1,977	1,877	1,775
Holtsville 04	54.3	(4.99)	49.31	318	388	360	323	277	2,178	2,064	1,974	1,874	1,772
Holtsville 05	53.4	(4.91)	48.49	319	389	360	324	277	2,179	2,065	1,975	1,875	1,773
Holtsville 06	49.1	(4.51)	44.59	323	392	364	328	281	2,183	2,069	1,979	1,879	1,777
Holtsville 07	53.0	(4.87)	48.13	320	389	361	324	278	2,180	2,065	1,976	1,875	1,773
Holtsville 08	52.1	(4.79)	47.31	320	390	362	325	279	2,180	2,066	1,976	1,876	1,774
Holtsville 09	54.2	(4.98)	49.22	319	388	360	323	277	2,179	2,064	1,974	1,874	1,772
Holtsville 10	46.1	(4.24)	41.86	326	395	367	331	284	2,186	2,071	1,982	1,881	1,779

Additional Outage Impacts - Long Island													
			Year	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Long Island Transmission Security Margin, Summer Peak - High Demand Forecast Expected Summer Weather, Normal Transfer Criteria (MW) (1)				368	437	409	372	326	2,228	2,113	2,024	1,923	1,821
Unit Name	Summer DMNC (MW)	NERC 5-Year Class Average De-Rate (MW)	Summer De-Rated Capability (MW)	Transmission Security Margin Considering Outage of Generator/Plant (Retire, Mothball, or IIFO)									
Shoreham GT 3 & 4	83.3	(8.75)	74.55	293	362	334	298	251	2,153	2,039	1,949	1,849	1,747
Shoreham GT3	42.1	(4.42)	37.68	330	399	371	335	288	2,190	2,076	1,986	1,885	1,783
Shoreham GT4	41.2	(4.33)	36.87	331	400	372	336	289	2,191	2,076	1,987	1,886	1,784
East Hampton GT 01, 2, 3, & 4	24.2	(2.53)	21.67	346	415	387	351	304	2,206	2,092	2,002	1,901	1,799
East Hampton GT 01	18.2	(1.67)	16.53	351	421	392	356	309	2,211	2,097	2,007	1,907	1,805
East Hampton 2	2.0	(0.29)	1.71	366	435	407	371	324	2,226	2,112	2,022	1,921	1,819
East Hampton 3	2.0	(0.29)	1.71	366	435	407	371	324	2,226	2,112	2,022	1,921	1,819
East Hampton 4	2.0	(0.29)	1.71	366	435	407	371	324	2,226	2,112	2,022	1,921	1,819
Southold 1	9.4	(0.99)	8.41	359	429	401	364	317	2,219	2,105	2,015	1,915	1,813
S Hampton 1	7.8	(0.82)	6.98	361	430	402	365	319	2,221	2,106	2,017	1,916	1,814
Freeport CT 1 & 2	88.9	(9.33)	79.57	288	357	329	293	246	2,148	2,034	1,944	1,844	1,742
Freeport CT 1	45.9	(4.82)	41.08	327	396	368	331	285	2,187	2,072	1,983	1,882	1,780
Freeport CT 2	43.0	(4.52)	38.49	329	399	370	334	287	2,189	2,075	1,985	1,885	1,783
Flynn	139.5	(6.18)	133.32	234	304	276	239	193	2,094	1,980	1,890	1,790	1,688
Greenport GT1	51.2	(4.71)	46.49	321	391	362	326	279	2,181	2,067	1,977	1,877	1,775
Far Rockaway GT1 & GT2	104.6	(9.61)	94.99	273	342	314	277	231	2,133	2,018	1,929	1,828	1,726
Far Rockaway GT1	48.9	(4.49)	44.41	323	393	365	328	281	2,183	2,069	1,979	1,879	1,777
Far Rockaway GT2	55.7	(5.12)	50.58	317	386	358	322	275	2,177	2,063	1,973	1,873	1,771
Bethpage	52.0	(2.30)	49.70	318	387	359	323	276	2,178	2,064	1,974	1,873	1,771
Bethpage 3	76.0	(3.37)	72.63	295	364	336	300	253	2,155	2,041	1,951	1,851	1,749
Bethpage GT4	43.6	(4.58)	39.02	329	398	370	333	287	2,189	2,074	1,985	1,884	1,782
Stony Brook (BTM:NG)	0.0	0.00	0.00	368	437	409	372	326	2,228	2,113	2,024	1,923	1,821
Brentwood	45.0	(4.73)	40.28	327	397	369	332	286	2,187	2,073	1,983	1,883	1,781
Pilgrim GT1 & GT2	83.8	(8.80)	75.00	293	362	334	297	251	2,153	2,038	1,949	1,848	1,746
Pilgrim GT1	41.9	(4.40)	37.50	330	400	371	335	288	2,190	2,076	1,986	1,886	1,784
Pilgrim GT2	41.9	(4.40)	37.50	330	400	371	335	288	2,190	2,076	1,986	1,886	1,784
Pinelawn Power 1	73.4	(3.25)	70.15	298	367	339	302	256	2,158	2,043	1,954	1,853	1,751
Caithness_CC_1	306.9	(13.60)	293.30	74	144	116	79	33	1,934	1,820	1,730	1,630	1,528
Islip (RR)	8.5	(0.89)	7.61	360	429	401	365	318	2,220	2,106	2,016	1,916	1,814
Babylon (RR)	15.6	(1.64)	13.96	354	423	395	358	312	2,214	2,099	2,010	1,909	1,807
Huntington (RR)	24.7	(2.59)	22.11	346	415	387	350	304	2,206	2,091	2,002	1,901	1,799

Notes

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