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Clean Final Draft of the Appendices
December 5th , 2025

New York Control Area Installed Capacity Requirement

For the Period May 2026 To April 2027

December 5, 2025

New York State Reliability Council, LLC
Installed Capacity Subcommittee

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Appendix A

NYCA Installed Capacity Requirement

Reliability Calculation Models and Assumptions

Description of the GE MARS Program: Load, Capacity, Transmission, Outside World Model, and Assumptions

A. Reliability Calculation Models and Assumptions – Appendix A

The reliability calculation process for determining the New York Control Area (NYCA) Installed Reserve Margin (IRM) requirement utilizes a probabilistic approach. This technique calculates the probabilities of outages of generating units, in conjunction with load and transmission models, to determine the number of days per year of expected capacity shortages. The General Electric Multi-Area Reliability Simulation (GE-MARS) is the primary computer program used for this probabilistic analysis. The result of the calculation for "Loss of Load Expectation" (LOLE) provides a consistent measure of system reliability. The various models used in the NYCA IRM calculation process are depicted in Figure A.1 below.

Table A.1 lists the study parameters, the source for the study assumptions, and where the assumptions are described in Appendix A. Finally, section A.3 compares the assumptions used in the 2025-2026 and 2026-2027 IRM reports.

Figure A.1 NYCA Installed Capacity (ICAP) Modeling

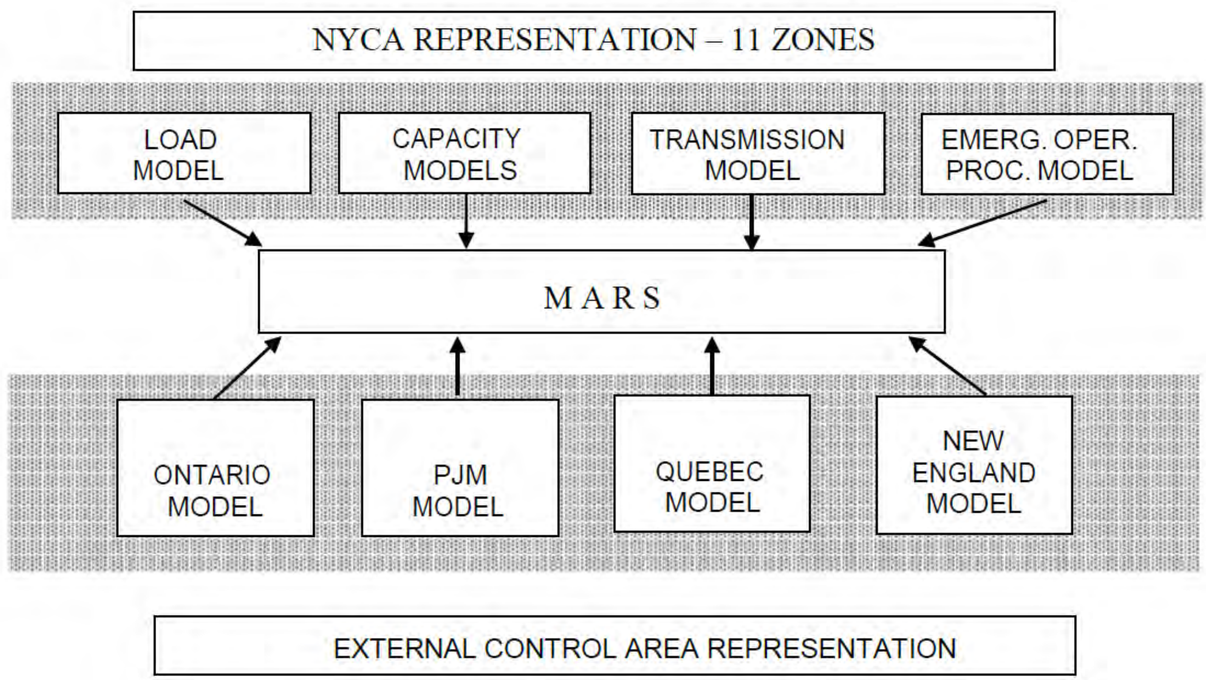


Table A.1 Modeling Details

#	Parameter	Description	Source	Reference
Internal NYCA Modeling				
1	GE-MARS	General Electric Multi-Area Reliability Simulation Program		Section A.1
2	11 Zones	Load Areas	Fig A.1	NYISO Accounting & Billing Manual
3	Zone Capacity Models	Generator models for each generating in Zone Generator availability Unit ratings	GADS data 2025 Gold Book[1]	Section A.3.4
4	Emergency Operating Procedures	Reduces load during emergency conditions to maintain operating reserves	NYISO	Section A.3.5
5	Zone Load Models	Hourly loads	NYCA load shape and peak forecasts	Section A.3.1
6	Load Uncertainty Model	Account for forecast uncertainty due to weather conditions	Historical data	Section A.3.3
7	Transmission Capacity Model	Emergency transfer limits of transmission interfaces between Zones	NYISO Transmission Studies	Section A.3.5
External Control Area Modeling				
8	Ontario, Quebec, ISONE, PJM Control Area Parameters	See items 9-12 in this table	Supplied by External Control Area	
9	External Control Area Capacity models	Generator models in neighboring Control Areas	Supplied by External Control Area	Section A.3.6
10	External Control Area Load Models	Hourly loads	Supplied by External Control Area	Section A.3.6
11	External Control Area Load Uncertainty Models	Account for forecast uncertainty due to weather conditions	Supplied by External Control Area	Section A.3.6
12	Interconnection Capacity Models	Emergency transfer limits of transmission interfaces between control areas.	Supplied by External Control Area	Section A.3.6

[1] 2025 Load and Capacity Data report ("2025 Gold Book"), https://www.nyiso.com/documents/20142/2226333/2025-Gold-Book-Public.pdf

A.1 GE-MARS

As the primary probabilistic analysis tool used for establishing NYCA IRM requirements, the GE-MARS program includes a detailed load, generation, and transmission representation for 11 NYCA Load Zones, as well as the four external Control Areas (Outside World Areas) interconnected to the NYCA (see Section A.3 for a description of these Load Zones and Outside World Areas).

A sequential Monte Carlo simulation forms the basis for GE-MARS. The Monte Carlo method provides a fast, versatile, and easily expandable program that can be used to fully model many different types of generation, transmission, and demand-side options. GE-MARS calculates the standard reliability indices of daily and hourly LOLE (event-days/year and event-hours/year) and Loss of Energy Expectation (LOEE in MWh/year). The use of sequential Monte Carlo simulation allows for the calculation of time-correlated measures such as frequency (outages/year) and duration (hours/outage). The program also calculates the need for initiating Emergency Operating Procedures (EOPs), expressed in days/year (see Section A.3.5).

In addition to calculating the expected values for the reliability indices, GE-MARS also produces probability distributions that show the actual yearly variations in reliability that the NYCA could be expected to experience. In determining NYCA reliability, there are several types of randomly occurring events that must be taken into consideration. Among these are the forced outages of generating units and transmission capacity. Monte Carlo simulation models the effects of such random events. Deviations from the forecasted loads are captured using a load forecast uncertainty model.

Monte Carlo simulation approaches can be categorized as “non-sequential” and “sequential.” A non-sequential simulation process does not move through time chronologically or sequentially but rather considers each hour independent of every other hour. Because of this, non-sequential simulation cannot accurately model issues that involve time correlations, such as maintenance outages, and cannot be used to calculate time-related indices such as frequency and duration.

Sequential Monte Carlo simulation (used by GE-MARS) steps through the year chronologically, recognizing the status of equipment is not independent of its status in adjacent hours. Equipment forced outages are modeled by taking the equipment out of service for contiguous hours, with the length of the outage period being determined from the equipment’s mean time to repair. Sequential simulation can model issues of concern that involve time correlations and can be used to calculate indices such as frequency and duration. It also models transfer limitations between individual areas.

Because the GE-MARS program is based on a sequential Monte Carlo simulation, it uses state transition rates, rather than state probabilities, to describe the random forced outages of the thermal units. State probabilities give the probability of a unit being in a given capacity state at any particular time and can be used if one assumes that the unit's capacity state for a given hour is independent of its state at any other hour. Sequential Monte Carlo simulation recognizes the fact that a unit's capacity state in any given hour is dependent on a given state in previous hours and influences its state in future hours. It thus requires additional information that is contained in the transition rate data.

For each unit, a transition rate matrix is input that shows the transition rates to go from each capacity state to each other capacity state. The transition rate from state A to state B is defined as the number of transitions from A to B per unit of time in state A (Equation A.1).

Equation A.1 Transition Rate Definition

$$Transition\ (A\ to\ B) = \frac{Number\ of\ Transitions\ from\ A\ to\ B}{Total\ Time\ in\ State\ A}$$

Table A.2 shows the calculation of the state transition rates from historic data for one year. The "Time-in-State Data" shows the amount of time that the unit spent in each of the available capacity states during the year; the unit was on planned outage for the remaining 760 hours of the year. The "Transition Data" shows the number of times that the unit transitioned from each state to each other state during the year. The "State Transition Rates" can be calculated from this data. For example, the transition rate from state 1 to state 2 equals the number of transitions from 1 to 2 divided by the total time spent in state 1 (Equation A.2).

Equation A.2 Transition Rate Calculation Example

$$Transition\ (1\ to\ 2) = \frac{(10\ Transitions)}{5{,}000\ Hours} = 0.0002$$

Table A.2 State Transition Rate Example

Time in State Data				Transition Data			
State	MW	Hours		From State	To State 1	To State 2	To State 3
1	200	5000		1	0	10	5
2	100	2000		2	6	0	12
3	0	1000		3	9	8	0

State Transition Rates			
From State	To State 1	To State 2	To State 3
1	0.000	0.002	0.001
2	0.003	0.000	0.006
3	0.009	0.008	0.000

From the state transition rates for a unit, the program calculates the two important quantities that are needed to model the random forced outages on the unit: the average time that the unit resides in each capacity state, and the probability of the unit transitioning from each state to each other state.

Whenever a unit changes capacity states, two random numbers are generated. The first is used to calculate the amount of time that the unit will spend in the current state; it is assumed that the time in a state is exponentially distributed, with a mean as computed from the transition rates. This time in state is added to the current simulation time to calculate when the next random state change will occur. The second random number is combined with the state transition probabilities to determine the state to which the unit will transition when it leaves its current state. The program thus knows for every unit on the system, its current state, when it will be leaving that state, and the state to which it will go next.

Each time a unit changes state, because of random state changes, the beginning or ending of planned outages, or mid-year installations or retirements, the total capacity available in the unit's area is updated to reflect the change in the unit's available capacity. This total capacity is then used in computing the area margins each hour.

(1) <u>Error Analysis</u>

An important issue in using Monte Carlo simulation programs such as GE-MARS is the number of years of artificial history (or replications) that must be created to achieve an acceptable level of statistical convergence in the expected value of the reliability index of interest. The degree of statistical convergence is measured by the standard deviation of the estimate of the reliability index that is calculated from the simulation data.

The standard deviation has the same physical units (*e.g.,* days/year) as the index being estimated, and thus its magnitude is a function of the type of index being estimated. Because the standard deviation can assume a wide range of values, the degree of convergence is often measured by the standard error, which is the standard deviation of the estimated mean expressed as a per unit of the mean.

Convergence can also be expressed in terms of a confidence interval that defines the range in which you can state, with a given level of confidence that the actual value falls within the interval. For example, a range centered on the mean of two standard deviations in each direction (plus and minus) defines a confidence interval of 95%.

Prior to the Tan45, the Final Base Case required 2,069 replications to converge to a standard error of 0.05 and required 8,581 replications to converge to a standard error of 0.025. For the final parametric case prior to the Tan45, the model was run to 8,750 replications at which point the daily LOLE of 0.100 Event-Days/year for NYCA was met with a standard error less than 0.025. The significant number of replications required to meet the standard error criteria would significantly increase the runtime of the Tan45 case. In order to complete the 2026-2027 IRM study on time, an exception was granted by the Executive Committee to reduce the confidence level to 90% instead of 95% for the Tan45 of the Final Base Case and associated Special Sensitivity Case. Potential longer-term solutions to address the possibility that similar concerns could arise in future IRM study cycles will be reviewed in 2026. The Final Base Case Tan45 was conducted with 3,000 replications, finishing with a standard error of 0.0299 and representing a 94% confidence level. The confidence interval at this point ranges from 25.0% to 25.5%.

(2) Conduct of the GE-MARS analysis

The study was performed using Version 5.8.3837 of the GE-MARS software program. This version has been benchmark tested by the NYISO.

The current base case is the culmination of the individual changes made to last year's base case. Each change, however, is evaluated individually against last year's base case. The LOLE results of each of these pre-base case simulations are reviewed to confirm that the reliability impact of the change is reasonable and explainable.

General Electric was asked to review the input data for errors. They have developed a program called "Data Scrub" which processes the input files and flags data that appears to be out of the ordinary. For example, it can identify a unit with a forced outage rate significantly higher than all the others in that size and type category. If something is found, the NYISO reviews the data and either confirms that it is correct as is or institutes a correction. The results of this data scrub are shown in Section A.4.

The top three summer peak loads of all Areas external to NYCA are aligned to be on the same days as that of NYCA, even though they may have historically occurred at different times. This is a conservative approach, using the assumption that peak conditions could be the result of a widespread heat wave. This would result in reducing the amount of assistance that NYCA could receive from the external Areas.

A.2 Unified Methodology

The 2026-2027 IRM study continues to use the Unified Methodology that simultaneously provides a basis for the NYCA installed reserve requirements and the preliminary locational installed capacity requirements (referred to as related Minimum Locational Capacity Requirements or "MLCRs"). The IRM/MLCR characteristic consists of a curve function, "a knee of the curve" and straight-line segments at the asymptotes. The curve function is represented by a quadratic (second order) curve which is the basis for the Tan 45 inflection point calculation. Inclusion of IRM/MLCR point pairs remote to the "knee of the curve" may impact the calculation of the quadratic curve function used for the Tan 45 calculation.

The procedure for determining the best fit curve function used for the calculation of the Tan 45 inflection point to define the base case requirement is based on the following methodology:

1) Start with all points on IRM/MLCR characteristic.
2) Develop regression curve equations for all different point to point segments consisting of at least four consecutive points.
3) Rank all the regression curve equations based on the following:
   - Sort regression equations with highest R2.
   - Remove any equations which show a negative coefficient in the first term. This is the constant labeled 'a' in the quadratic equation: ax^2+bx+c
   - Ensure the calculated IRM is within the selected point pair range (*e.g.*, if the curve fit was developed between 14% and 18% and the calculated IRM is 13.9%, the calculation is invalid).

- In addition, there must be at least one statewide reserve margin point to the left and right of the calculated Tan 45 point.
- Determine that the calculated IRM and corresponding MLCR do not violate the 0.1 Event-Days/year LOLE criteria.
- Check results to determine that they are consistent with visual inspection methodology used in past years' studies.

This approach identifies the quadratic curve functions with highest R^2 correlations as the basis for the Tan 45 calculation. The final IRM is obtained by averaging the Tan 45 IRM points of the New York City and Long Island curves. The Tan 45 points are determined by solving for the first derivatives of each of the "best fit" quadratic functions as a slope of -1. Lastly, the resulting MLCR values are identified.

A.3 Base Case Modeling Assumptions

A.3.1 Load Model

Table A.3 Load Model

Parameter	2025-2026 Study Assumption	2026-2027 Study Assumption	Explanation
Peak Load	2024 Fall Load Forecast NYCA: 31,649.7 MW NYC: 11,043.9 MW LI: 5,092.1 MW G-J: 15,205.1 MW	2025 Fall Load Forecast NYCA: 31,648.2 MW NYC: 11,088.8 MW LI: 5,127.8 MW G-J: 15,304.8 MW	Forecast based on examination of 2025 weather normalized peaks, 2026 economic and expected weather projections, and Transmission Owner projections.
Peak Load Winter		2025 Fall Load Forecast NYCA: 24,522.6 MW NYC: 7,642.4 MW LI: 3,327.4 MW G-J: 10,775.4 MW	New for 2026-2027 IRM study with the adoption of the Enhanced Load Modeling and Behind-the-Meter (BTM) Solar Modeling enhancements.

Table A.3 Continued on Top of Next Page

Parameter	2025-2026 Study Assumption	2026-2027 Study Assumption	Explanation
Load Shape Model	Multiple Load Shapes Model using years: 2013 (Bins 1 & 2), 2018 (Bins 3 & 4), and 2017 (Bin 5-7)	Multiple Load Shapes Model using years: 2013 (Bins 1 & 2), 2018 (Bins 3 & 4), and 2017 (Bin 5-7)	No change for the 2025-2026 IRM Study
Load Forecast Uncertainty (LFU) Models	Statewide and zonal models updated to reflect current data	Statewide and zonal models reviewed based on current data	No change for the summer and a small change for winter

(1) Peak Load Forecast Methodology

The procedure for preparing the IRM forecast is very similar to that described in the NYISO Load Forecasting Manual for the ICAP market forecast. The NYISO and transmission owners developed regression models to evaluate the relationship between regional weather and transmission district summer weekday peak loads, using data from the summer of 2025 and other recent summers as needed. The resulting estimates of weather response (*i.e.*, the MW increase in load per degree of increase in the weather variable) by transmission district were used to develop 2025 transmission district weather adjustments, which normalize the peaks to typical summer peak weather conditions. For purposes of the IRM and ICAP market forecasts, the NYISO evaluates the system peak load that occurs during non-holiday weekdays in July and August. In 2025, the system peak load during this period was on July 29th, the hour beginning 18:00. The aggregate system peak load of 30,377.9 MW is shown by transmission district in Table A.4 (col. 2). The total MW adjustment (col. 3), including the weather adjustment, and estimated demand response and municipal self-generation impacts were added to the system peak, producing the 2025 weather normalized peak load 31,330.1 MW (col. 4). Load and weather data from other summer 2025 high load days were considered in the determination of final 2025 transmission district weather adjustments for the 2026-2027 IRM study forecast.

Several transmission owners developed updated estimates of the regional load growth factor (RLGF) for their respective territories. The RLGF represents the ratio of forecasted 2026 summer peak load to the 2025 weather normalized peak, based on the anticipated load growth or decline in the territory (excluding large load projects). Summer peak load growth rates from the NYISO's 2025 Load & Capacity Data report (Gold Book) forecast and other NYISO analyses were used to determine RLGFs for transmission owners that did not provide their own values. The final RLGFs (col. 6) were reviewed by the NYISO and discussed with the transmission owners as needed. The 2026 summer peak load forecast before adjustments (col. 7) is the product of the 2025 weather normalized peaks (excluding large loads) and the RLGFs. Summer 2026 large load projections are then added (col. 8). The resulting sum (col. 9) represents the 2026-2027 IRM study coincident peak forecast of 31,551.6 MW before Behind-the-Meter Net Generation (BTM:NG) adjustments. This forecast is a 1.4% decrease relative to the 2026 peak load forecast from the 2025 Gold Book. For purposes of modeling in the IRM study, the forecast of BTM:NG resource load is added (col. 10), producing a total forecast of 31,648.2 MW inclusive of BTM:NG resource load (col. 11).

The Locality forecasts are reported in Table A.5. These forecasts are the product of the weather normalized coincident peak load in the Locality, the non-coincident to coincident peak (NCP to CP) ratio in the Locality, and the RLGF(s) of the transmission district(s) in the Locality, plus any applicable large load growth in the Locality. The Locality NCP to CP ratios were calculated using the historical 15-year ratio (excluding outlier years). The Locality forecasts of 11,088.8 MW (Load Zone J), 5,127.8 MW (Load Zone K), and 15,304.8 MW (G-J Locality), inclusive of BTM:NG loads, are shown in column 11 of Table A.5.

Table A.6 provides the final zonal annual energy and summer and winter peak forecasts for the 2026-2027 IRM study. The zonal energy forecasts shown in Table A.6 include the projected impacts of BTM:NG resource load and large load projects.

Zonal summer coincident peak forecasts were generally derived using sub-zonal load shares (transmission district to Load Zone), based upon peak and near-peak load hours from recent summers. Zonal non-coincident peak forecasts were calculated by multiplying the coincident peak forecast by zonal NCP to CP ratios.

With implementation of the Enhanced Load Modeling (ELM) procedure for the 2026-2027 IRM study, the load shapes included in the GE Multi-Area Reliability Simulation software program (MARS) model are calibrated to zonal annual energy and winter peaks, in addition to summer peaks. Zonal annual energy and winter peak forecasts from the 2025 Gold Book were updated solely to account for updated large load and BTM:NG resource load projections.

The peak load forecasts, along with the regression models, weather adjustments, RLGFs, large load projections, zonal load shares, and NCP to CP ratios used to derive such forecasts were discussed and approved by the NYISO Load Forecasting Task Force (LFTF) and the NYSRC Installed Capacity Subcommittee (ICS).

Table A.4 2026 Final NYCA Peak Load Forecast – Coincident Peak

2026 IRM Summer Coincident Peak Forecast										
(1)	(2)	(3)	(4) =(2)+(3)	(5)	(6)	(7) =(5)*(6)	(8)	(9) =(7)+(8)	(10)	(11) =(9)+(10)
Transmission District	2025 Actual MW, 7/29/2025 HB 18	Total Adjustment (Demand Response + Muni Self-Gen + Wthr Adjustment) MW	2025 Weather Normalized Coincident Peak MW	2025 WN Peak MW Excluding Large Loads	Regional Load Growth Factor	2026 Forecast, Before Adjustments MW	Large Loads MW	2026 IRM Forecast, With Large Loads, Before BTM:NG Adjustments MW	BTM:NG Forecast MW	TO Forecast, With Large Loads and BTM:NG Adjustments MW
Con Edison	11,785.1	515.9	12,301.0	12,301.0	1.0064	12,379.1	0.0	12,379.1	17.4	12,396.5
Cen Hudson	1,115.0	-11.6	1,103.4	1,103.4	1.0038	1,107.6	0.0	1,107.6	0.0	1,107.6
LIPA	5,209.5	-151.3	5,058.2	5,058.2	0.9888	5,001.3	0.0	5,001.3	38.4	5,039.7
Nat Grid	6,357.2	358.2	6,715.4	6,519.9	1.0000	6,519.9	351.0	6,870.9	1.6	6,872.5
NYPA	306.9	169.5	476.4	316.4	1.0000	316.4	160.0	476.4	0.0	476.4
NYSEG	3,053.5	39.5	3,093.0	3,093.0	0.9930	3,071.3	0.0	3,071.3	2.6	3,073.9
O&R	1,120.0	-21.8	1,098.2	1,066.2	1.0264	1,094.4	72.0	1,166.4	0.0	1,166.4
RG&E	1,430.7	53.8	1,484.5	1,484.5	0.9960	1,478.6	0.0	1,478.6	36.6	1,515.2
NYCA	30,377.9	952.2	31,330.1	30,942.6	1.0008	30,968.6	583.0	31,551.6	96.6	31,648.2

2026 Forecast from 2025 Gold Book	31,990.0
Change from 2025 Gold Book	-438.4
Percent Change	-1.4%

Table A.5 2026 Final NYCA Peak Load Forecast – Locality Peaks

2026 IRM Summer Locality Peak Forecasts										
(1)	(2)	(3)	(4)	(5)	(6) =(3)*(4)+(5)	(7)	(8) =(7)-(6)	(9) =(8)/(7)	(10)	(11) =(9)+(10)
Locality	2025 Locality Peak MW	2025 Weather Normalized Locality Peak MW	Regional Load Growth Factor	Large Load Growth MW	2026 IRM Locality Peak Forecast Before BTM:NG Adjustments MW	2026 Forecast from 2025 Gold Book MW	Change from Gold Book Forecast MW	Percent Change from Gold Book Forecast	BTM:NG Forecast MW	Locality Peak Forecast, Including BTM:NG Adjustments MW
Zone J - NYC	10,360.7	11,001.5	1.0064	0.0	11,071.4	11,030.0	41.4	0.4%	17.4	11,088.8
Zone K - LIPA	5,352.8	5,147.2	0.9888	0.0	5,089.4	5,072.0	17.4	0.3%	38.4	5,127.8
Zones G-to-J	14,586.9	15,136.1	1.0074	40.0	15,287.4	15,280.0	7.4	0.0%	17.4	15,304.8

Table A.6 Final 2026-2027 Zonal Load Forecasts

2026-27 IRM Zonal Forecasts Including BTM:NG Adjustments for Final Base Case

Annual Energy - GWh												
Year	A	B	C	D	E	F	G	H	I	J	K	NYCA
2026	16,124.0	9,600.6	14,302.7	5,620.0	7,190.0	11,240.0	9,590.0	2,790.0	5,910.0	50,252.4	20,376.3	152,996.0

Summer Coincident Peak Demand - MW												
Year	A	B	C	D	E	F	G	H	I	J	K	NYCA
2026	2,914.4	1,882.3	2,582.1	658.8	1,274.6	2,261.1	2,290.1	599.9	1,321.2	10,824.0	5,039.7	31,648.2

Summer Non-Coincident Peak Demand - MW											
Year	A	B	C	D	E	F	G	H	I	J	K
2026-27	3,018.1	1,944.3	2,671.1	671.3	1,313.6	2,330.1	2,350.1	614.6	1,353.6	11,088.8	5,127.8

Summer G-to-J Locality Peak Demand - MW												
Year	A	B	C	D	E	F	G	H	I	J	K	G-to-J
2026							2,331.3	610.6	1,345.0	11,017.9		15,304.8

Winter Coincident Peak Demand - MW												
Year	A	B	C	D	E	F	G	H	I	J	K	NYCA
2026	2,314.6	1,561.6	2,513.6	827.0	1,333.0	1,917.0	1,672.0	525.0	947.0	7,597.4	3,314.4	24,522.6

Winter Non-Coincident Peak Demand - MW											
Year	A	B	C	D	E	F	G	H	I	J	K
2026-27	2,342.6	1,572.6	2,523.6	852.0	1,358.0	1,930.0	1,677.0	536.0	953.0	7,647.4	3,327.4

Winter G-to-J Locality Peak Demand - MW												
Year	A	B	C	D	E	F	G	H	I	J	K	G-to-J
2026							1,667.0	523.0	943.0	7,642.4		10,775.4

(2) Zonal Load Forecast Uncertainty

Each year, the NYISO and the applicable transmission owners review load and weather data from the most recent summer and winter to determine whether updated load forecast uncertainty (LFU) models are needed. Based on an analysis of the winter 2024-2025 weather data, the NYISO determined that the base winter LFU model should be updated.

The summer LFU models were not updated in 2025, and the summer LFU multipliers used in the 2025-2026 IRM study are retained for the 2026-2027 IRM study. Summer peak temperatures were below normal in summer 2024. Since peak temperatures were below normal for the summer, there was no additional information to benefit the fit of load to the extreme upper-bin weather conditions impactful to resource adequacy modeling, and the summer LFU models were not updated. The current summer LFU models were developed during the spring of 2023. The NYISO and pertinent transmission owners developed updated load-weather regression models inclusive of summer 2022 data.

(3) Review of Load-Weather Relationship

Summer regression models were developed for all LFU modeling regions (Load Zones A-E, Load Zones F&G, Load Zones H&I, Load Zone J, and Load Zone K) to establish the recent load-weather relationship. The NYISO developed models for the Load Zones A-E and Load Zones F&G regions. Models for the Load Zones H&I and Load Zone J areas were developed in conjunction with Consolidated Edison. The Load Zone K model was developed by Long Island Power Authority (LIPA) and reviewed by the NYISO. The ICS initially approved the 2023 LFU model results for use in the 2024-2025 IRM study. Due to the lack of extreme weather over recent summers, the resulting LFU multipliers are retained for the 2026-2027 IRM study.

The NYISO regional summer models established the load-weather relationship through polynomial regressions (generally 3rd order, or cubic). Pooled models using 2019, 2021, and 2022 summer data were developed. Multiple model structure combinations were investigated for each region. The optimal pooled model was selected for each LFU area based on statistical model accuracy and the resulting weather sensitivity. The weather distribution used to define the LFU bin reference temperatures was calculated using 30 years of system peak-producing weather days. This distribution was applied to the load-weather relationship established by the selected regression models to calculate the LFU multipliers for each area. LIPA's splined linear model for Load Zone K utilized data from the 2013 through 2022 summers.

The NYISO developed an updated system-level winter LFU model for the 2026-2027 IRM study, reflecting the load-weather relationship observed during the 2024-2025 winter.[2] The NYCA winter model utilized a 2nd order polynomial regression fit through winter 2018-2019, 2022-2023, & 2024-2025 load and weather data. The winter LFU model used the winter weather variable developed as part of the LFU Phase 3 analysis, based on temperature and wind speed. The resulting multipliers were quite similar to the prior winter LFU multipliers, with slight increases in the upper-bin values, suggesting a minor increase in winter load sensitivity to weather. All model results were presented to and reviewed by the LFTF and ICS.

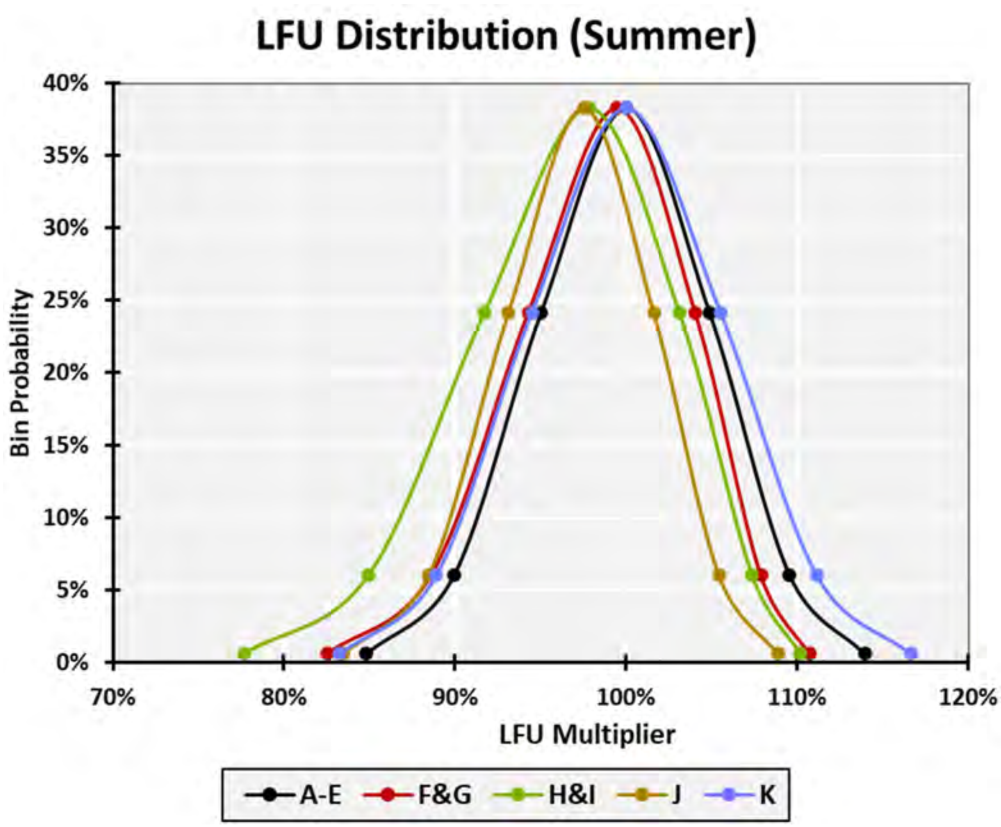
The 2026-2027 IRM study LFU multipliers are presented in Table A.7. The rows list the seven bin levels and their probability of occurrence, along with the associated per-unit load multipliers by LFU area. These results are presented graphically in Figure A.2.

[2] 2026 LFU Model Updates: https://www.nysrc.org/wp-content/uploads/2025/05/2026_LFU_Updates_ICS06042025.pdf

Table A.7 2026-2027 IRM Study Summer and Winter Load Forecast Uncertainty Multipliers

			Summer					Winter
Bin	Bin z	Bin Probability	A-E	F&G	H&I	J	K	NYCA
Bin 1	2.74	0.62%	113.93%	110.69%	110.18%	108.88%	116.62%	110.48%
Bin 2	1.79	6.06%	109.54%	107.86%	107.34%	105.42%	111.14%	106.68%
Bin 3	0.89	24.17%	104.86%	104.04%	103.09%	101.61%	105.52%	103.22%
Bin 4	0.00	38.29%	100.00%	99.46%	97.81%	97.51%	100.00%	100.00%
Bin 5	-0.87	24.17%	95.00%	94.29%	91.70%	93.12%	94.48%	96.96%
Bin 6	-1.79	6.06%	89.91%	88.61%	84.93%	88.45%	88.89%	94.02%
Bin 7	-2.74	0.62%	84.79%	82.53%	77.65%	83.48%	83.27%	91.16%

Figure A.2 Summer LFU Distributions



(4) <u>Additional Discussion LFU Models and Forecast Uncertainty</u>

The LFU models measure the load response to weather at extreme peak-producing temperatures and describe the variability in peak-day load caused by the uncertainty in peak-day weather. Other sources of uncertainty such as economic growth are not captured in LFU modeling. However, economic uncertainty is relatively small compared to temperature uncertainty one year ahead. As a result, the LFTF, the NYISO, and the ICS have agreed that it is sufficient to confine the LFU one year ahead to weather alone.

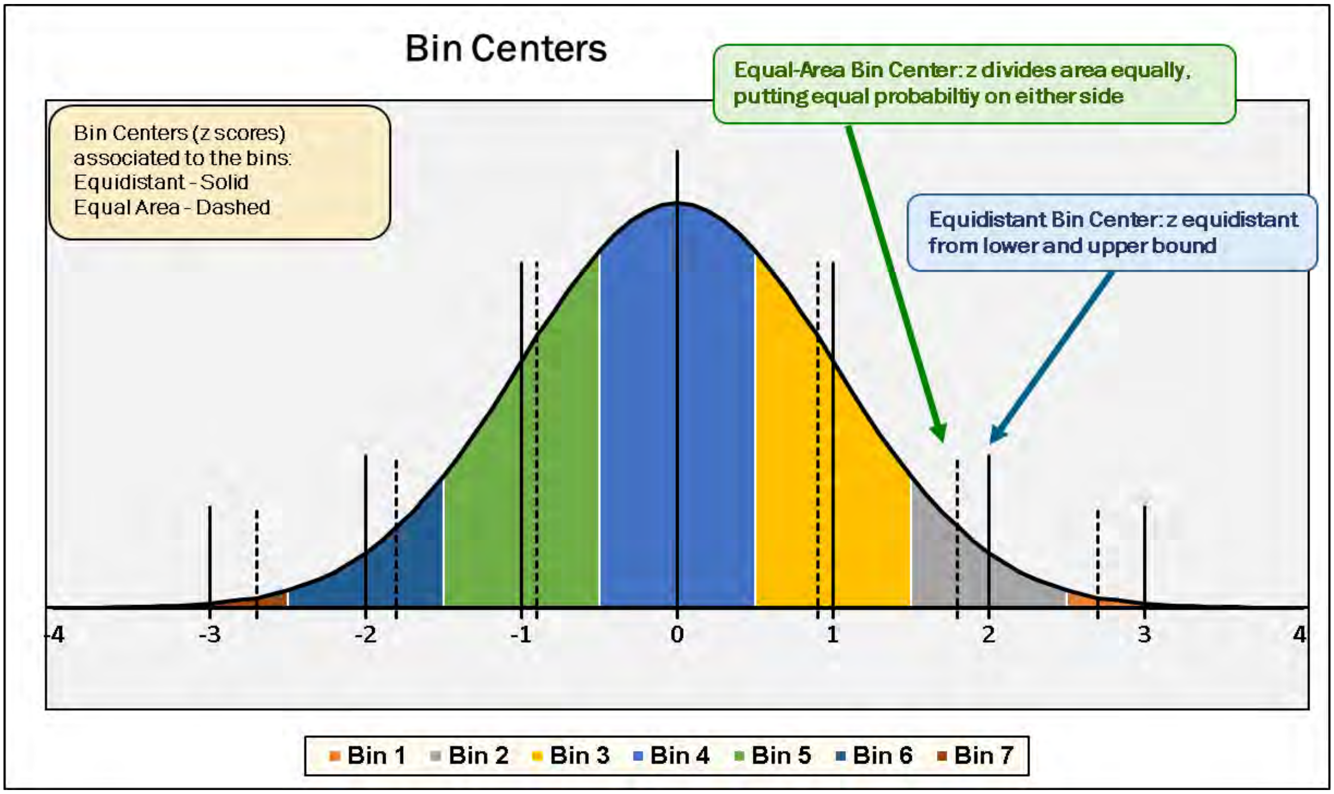
LFU multipliers are largely driven by the slope of load vs. temperature, or the weather response of load. If the weather response of load increases, the slope of load vs. temperature will increase, and the upper-bin LFU multipliers (Bins 1-3) will increase. Conversely, if the weather response of load decreases, upper-bin LFU multipliers will decrease.

The Consolidated Edison and Orange & Rockland summer peak load forecasts are based on peak weather conditions with a 1-in-3 probability of occurrence (67th percentile). All other transmission owners design their forecasts at a 1-in-2 probability of occurrence (50th percentile). The resulting design conditions are 50th percentile for the Load Zones A-E and Load Zone K LFU areas, above 50th percentile for Load Zones F&G and Load Zones H&I, and 67th percentile for Load Zone J. The NYCA aggregate design condition reflected in the summer LFU multipliers is the 57th percentile.

(5) LFU Bin Z-Values

Beginning with the LFU models used in the 2022-2023 IRM study, LFU bin centers are based on Z-values which divide the area of each bin equally. In prior LFU modeling, bin centers were defined using the x-axis, equidistant from the upper and lower bounds of each bin based on the Z-value. The equal-area Z-values reflect an improved representation of the LFU multiplier's probability of occurrence. The comparison between equidistant and equal area based bin structure is shown in Figure A.3 top of next page.

Figure A.3 Bin Centers (Equidistant v. Equal Area)



(6) <u>Review of Historical Zonal Load Shapes for Load Bins</u>

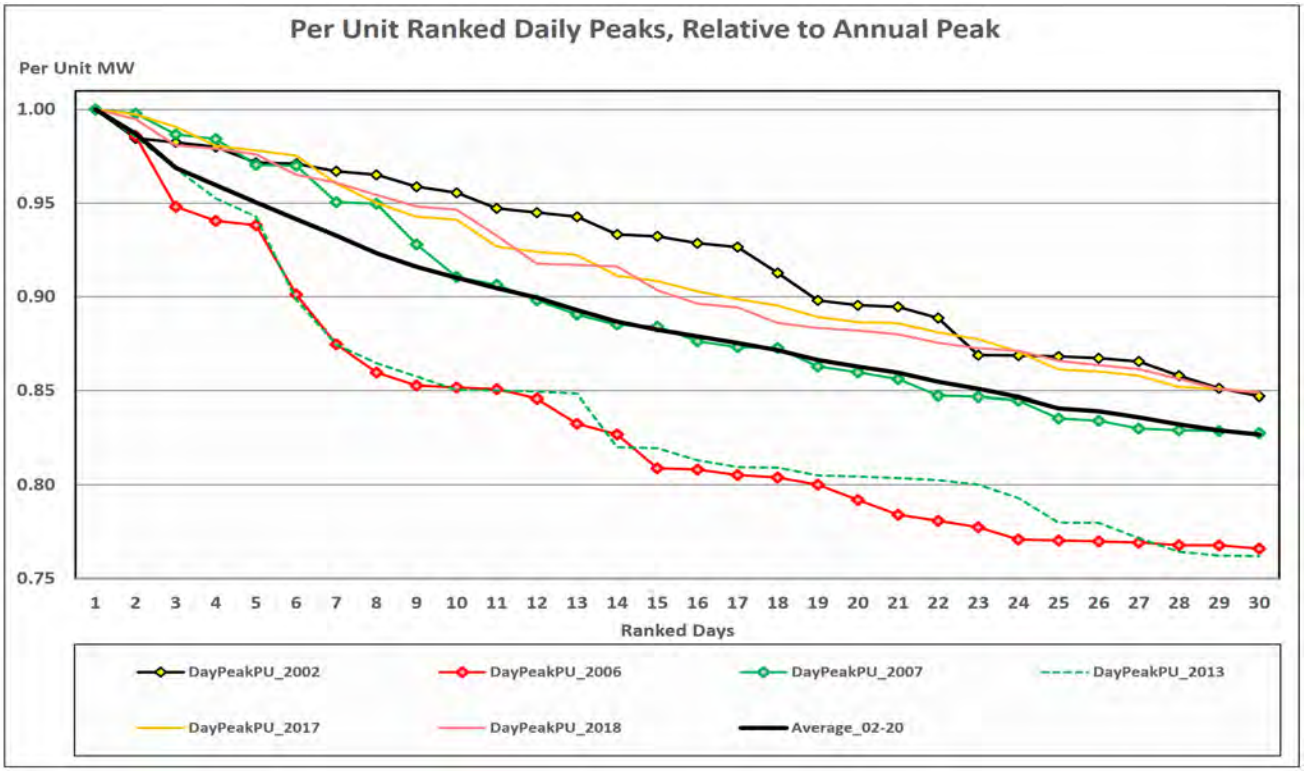
Beginning with the 2014-2015 IRM study, multiple years of historical load shapes were assigned to the load bins used in the study. Three historical years were selected from those available, as discussed in the NYISO's 2013 report, 'Modeling Multiple Load Shapes in Resource Adequacy Studies'. The year 2007 was assigned to the lowest five bins (from cumulative probability 0% to 93.32%). The year 2002 was assigned to the second highest bin, with a probability of 6.06%. The year 2006 was assigned to the highest bin (bin 1), with a probability of 0.62%.

Following the completion of the LFU Phase 2 analysis in 2022, the NYISO recommended and the ICS approved the use of the 2013, 2017, and 2018 load shapes beginning with the 2023-2024 IRM study.

A key finding of LFU Phase 2 was that extreme summers with hot weather and high peak loads typically have steep load duration curves, meaning that daily peak loads drop quickly relative to the summer peak load on a per-unit basis. Based on this finding, the 2013 load shape is assigned to bins 1 and 2 (upper 6.68% probability of occurrence). The 2013 load shape is reflective of a hot summer peak day and a very high peak load level.

The 2018 load shape, reflective of fairly typical peak day weather, is assigned to bins 3 and 4 (62.46% probability of occurrence, including the average load level). Finally, the 2017 load shape, reflective of a mild summer, is assigned to bins 5 through 7 (lower 30.85% probability of occurrence). Figure A.4 shows a comparison of the daily load duration curve for the 2002, 2006, 2007, 2013, 2017, and 2018 summers.

Figure A.4 Per Unit Summer Load Shapes



An additional LFU Phase 2 recommendation was to properly scale the historical load shapes to reflect the increasing capacity of behind-the-meter (BTM) solar in future years. BTM solar is modeled as a supply resource in the 2026-2027 IRM study base case, and input load shapes have been scaled to reflect the impacts associated with projected 2026 BTM solar capacity levels.

A.3.2 Capacity Model

The capacity model includes all NYCA generating units, including new and planned units, as well as units that are physically outside New York State that have met specific criteria to offer capacity in the New York Control Area. The 2025 Load and Capacity Data Report (commonly referred to as the "Gold Book") is the primary data source for these resources.

Table A.8 provides a summary of the capacity resource assumptions in the 2025-2026 IRM study.

Table A.8 Capacity Resources

Parameter	2025-2026 Study Assumption	2026-2027 Study Assumption	Explanation
Generating Unit Capacities	2024 Gold Book values. Use min (DMNC vs. CRIS) capacity value	2025 Gold Book values. Use min (DMNC vs. CRIS) capacity value	2025 Gold Book publication
Planned Generator Units	47.0 MW summer re-rating for thermal resources	0 MW of new units or summer re-rating for thermal resources	NYISO recommendation based on documented process[3]
Proposed and Existing Wind Resources	0 MW of offshore Wind Capacity additions with wind summer capability totaling 2,566.2 MW of qualifying wind.	277.6 MW of land-based wind capacity additions. 2,828.3 MW of qualifying wind	ICAP is based on clean energy standard (CES) agreements, interconnection queue, and ICS input.
Land Based Wind Shape	Actual hourly plant output over the period 2019-2023. New units will use zonal hourly averages or nearby units.	Actual hourly plant output over the period 2020-2024. New units will use zonal hourly averages or nearby units.	Program randomly selects a wind shape of hourly production over the years 2020-2024 for each model iteration.
Offshore Wind Shape	Normalized offshore wind shapes as published by NYISO over the period 2017-2021	Normalized offshore wind shapes as published by NYISO over the period 2020-2024	Program randomly selects a wind shape of hourly production from the five-year period for each model iteration

[3] The process includes the latest Gold Book publication, NYISO interconnection queue, and generation notifications.

Parameter	2025-2026 Study Assumption	2026-2027 Study Assumption	Explanation
Proposed and Existing Solar Resources	267 MW of utility-scale solar capacity additions totaling 571.4 MW of qualifying solar capacity.	0 MW of utility-scale solar capacity additions totaling 573.4 MW of qualifying solar capacity.	ICAP Resources connected to Bulk Electric System
Solar Shape	Actual hourly plant output over the period 2019-2023. New units will use zonal hourly averages or nearby units.	Actual hourly plant output over the period 2020-2024. New units will use zonal hourly averages or nearby units.	Program randomly selects a solar shape of hourly production over the years 2020-2024 for each model iteration.
BTM- NG Program	No new BTM:NG resources, total of 182.2 MW	No new BTM:NG resources, total Net ICAP of 265.2 MW (361.8 MW Gen, 96.6 MW Load)	Both the load and generation of the BTM:NG Resources are modeled.
Retirements, Mothballed units, and ICAP ineligible units	165.4 MW unit deactivations	851.9 MW generator deactivations and removals	2025 Gold Book publication and generator notifications
Forced and Partial Outage Rates	Five-year (2019-2023) GADS data for each unit represented. Those units with less than five years – use representative data.	Five-year (2020-2024) GADS data for each unit represented. Those units with less than five years – use representative data.	Transition Rates representing the Equivalent Forced Outage Rates (EFORd) during demand periods over the most recent five-year period (2020-2024)
Planned Outages	Based on schedules received by the NYISO. Not modeled for the 2025-2026 IRM study.	Based on schedules received by the NYISO. Not modeled for the 2026-2027 IRM study.	Modeling of generator maintenance in future IRM studies under review

Parameter	2025-2026 Study Assumption	2026-2027 Study Assumption	Explanation
Summer Maintenance	Nominal 50 MW – divided equally between Load Zones J & K	Nominal 50 MW – divided equally between Load Zones J & K	Review of most recent data
Gas Turbine Ambient Derate	De-rate based on provided temperature correction curves.	De-rate based on provided temperature correction curves.	Operational history indicates de-rates in line with manufacturer's curves
Small Hydro Resources	Actual hourly plant output over the period 2019-2023.	Actual hourly plant output over the period 2020-2024.	Program randomly selects a Hydro shape of hourly production over the years 2020-2024 for each model iteration.
Large Hydro	Probabilistic Model based on 5 years of GADS data 2019-2023.	Probabilistic Model based on 5 years of GADS data 2020-2024	Transition Rates representing the Equivalent Forced Outage Rates (EFORd) during demand periods over the most recent five-year period (2020-2024)
Landfill Gas (LFG)	Actual hourly plant output over the period 2019-2022	Actual hourly plant output over the period 2020-2024	Program randomly selects an LFG shape of hourly production from the most recent five-year period for each model iteration
Energy Limited Resources (ELRS)	Based upon elections made by August 1, 2024 ES and small EL3 output limitations lifted at HB14	Based upon elections made by August 1, 2025. ES and small EL3 output limitations lifted at HB14	Existing elections are made by August 1st and will be incorporated into the model.
Energy Storage Resources (ESRs)	0 MW of new battery storage additions. 20 MW of existing battery storage modeled	18 MW of new battery storage scheduled. 35 MW of battery storage modeled	ICAP based on NYSERDA/utility agreements, interconnection queue and ICS input.

Parameter	2025-2026 Study Assumption	2026-2027 Study Assumption	Explanation
Distributed Energy Resources (DERs)	N/A	480.5 MW of total DERs	New for 2026-2027 IRM study. Modeled according to the modeling principles outlines in the Phase 1 2024 DER Whitepaper. Modeled MW based on submitted enrollment by August 1st and accounting for resources transitioning from SCR program and Demand Side Ancillary Services Program (DSASP).

(1) Generating Unit Capacities

The capacity rating for each thermal generating unit is based on its Dependable Maximum Net Capability (DMNC). The source of DMNC ratings are seasonal tests required by procedures in the NYISO Installed Capacity Manual. Additionally, each generating resource has an associated Capacity Resource Interconnection Service (CRIS) value. When the associated CRIS value is less than the DMNC rating, the CRIS value is modeled. Wind units are rated at the lower of their CRIS value or their nameplate value in the model. The 2025 Gold Book, issued by the NYISO, is the source of those generating units and their ratings included on the capacity model.

(2) Planned Generator Units

There are 0 MW thermal unit additions or unit re-ratings (summer ratings).

(3) Wind Modeling

Wind generators are modeled as hourly load modifiers using hourly production data over the period 2020-2024. Each calendar production year represents an hourly wind shape for each wind facility from which the GE-MARS program will randomly select. New units will use the zonal hourly averages of current units within the same zone. As shown in Table A.9 a total of 2,828.3 MW of installed capacity is associated with wind.

Table A.9 Wind Generation

Wind				
Resource	Zone	CRIS (MW)	Summer Capability (MW)	Lesser of Summer Capability vs. CRIS
Arkwright Summit Wind Farm [WT]	A	78.4	78.4	78.4
Ball Hill Wind [WT]	A	100	107.5	100
Bliss Wind Power [WT]	A	100.5	100.5	100.5
Cassadaga Wind [WT]	A	126	126	126
Erie Wind [WT]	A	15	15	15
Steel Wind [WT]	A	20	20	20
Baron Winds (Phase 1 and 2) [WT]	C	300	238.4	238.4
Canandaigua Wind Power [WT]	C	125	125	125
Eight Point Wind Energy Center [WT]	C	101.2	111.2	101.2
High Sheldon Wind Farm [WT]	C	112.5	118.1	112.5
Howard Wind [WT]	C	57.4	55.4	55.4
Orangeville Wind Farm [WT]	C	94.4	93.9	93.9
Wethersfield Wind Power [WT]	C	126	126	126
Altona Wind Power [WT]	D	97.5	97.5	97.5
Chateaugay Wind Power [WT]	D	106.5	106.5	106.5
Clinton Wind Power [WT]	D	100.5	100.5	100.5
Ellenburg Wind Power [WT]	D	81	81	81
Jericho Rise Wind Farm [WT]	D	77.7	77.7	77.7
Marble River Wind [WT]	D	215.2	215.2	215.2
Bluestone Wind [WT]	E	124.2	111.8	111.8
Hardscrabble Wind [WT]	E	74	74	74
Maple Ridge Wind [WT01]	E	231	231	231
Maple Ridge Wind [WT02]	E	90.7	90.8	90.7
Munnsville Wind Power [WT]	E	34.5	34.5	34.5
Number 3 Wind Energy [WT]	E	105.8	103.9	103.9
Roaring Brook [WT]	E	79.7	79.7	79.7
South Fork Wind Farm (Offshore)	K	136	132	132
Total		**2,910.70**	**2,851.50**	**2,828.30**

(4) Solar Modeling

Solar generators are modeled as hourly load modifiers using hourly production data over the period 2019-2023. Each calendar production year represents an hourly solar shape for each solar facility which the GE-MARS program will randomly select from. As shown in Table A.10 top of next page, a total of 573.4 MW of solar capacity was modeled.

Table A.10 Solar Generation

Solar				
Resource	Zone	CRIS (MW)	Summer Capability (MW)	Lesser of Summer Capability vs. CRIS
Janis Solar [PV]	C	20.0	20.0	20.0
Morris Ridge Solar Energy Center	C	179.0	179.0	179.0
Puckett Solar [PV]	C	20.0	20.0	20.0
Albany County	F	20.0	20.0	20.0
Albany County II	F	20.0	20.0	20.0
Branscomb Solar [PV]	F	20.0	20.0	20.0
Darby Solar [PV]	F	20.0	20.0	20.0
East Point Solar	F	50.0	50.0	50.0
Grissom Solar [PV]	F	20.0	20.0	20.0
High River Solar	F	90.0	90.0	90.0
Pattersonville Solar [PV]	F	20.0	20.0	20.0
Regan Solar [PV]	F	20.0	20.0	20.0
ELP Stillwater Solar [PV]	F	20.0	20.0	20.0
Calverton Solar Energy Center [PV]	K	22.9	22.9	22.9
Long Island Solar Farm [PV]	K	31.5	31.5	31.5
Total		**573.4**	**573.4**	**573.4**

(5) Retirements/Deactivations/ ICAP Ineligible

There are 40 units totaling 851.9MW that are being deactivated for the 2026-2027 IRM study.

(6) Unforced Capacity Deliverability Rights (UDRs)

The capacity model includes UDRs, which are capacity rights that allow the owner of an incremental controllable transmission project to provide locational capacity benefits. Non-locational capacity, when coupled with a UDR to deliver capacity to a Locality, can be used to satisfy locational capacity requirements. The owners of the UDRs elect whether they will utilize their capacity deliverability rights on a confidential basis by August 1st for the upcoming Capability Year (*i.e.*, August 1, 2025 for the Capability Year beginning on May 1, 2026). This decision determines how this transfer capability will be represented in the GE-MARS model. The IRM modeling accounts for both the availability of the resource that is identified for each UDR line as well as the availability of the UDR facility itself. The following facilities are represented in the 2026-2027 IRM study as having UDR capacity rights: LIPA's 330 MW High Voltage Direct Current (HVDC) Cross Sound Cable, LIPA's 660 MW HVDC Neptune Cable, the 315 MW Linden Variable Frequency

Transformer and, new for the 2026-2027 IRM study, the Champlain Hudson Power Express: 1,250 MW UDR from HQ to Load Zone J.

The owners of these facilities have the option, on an annual basis, of selecting the MW quantity of UDRs they plan on utilizing for capacity contracts over these facilities. Any remaining capability on the cable can be used to support emergency assistance, which may reduce locational and IRM capacity requirements. The 2026-2027 IRM study incorporates the confidential elections that these facility owners made for the 2026-2027 Capability Year. Hudson Transmission Partners 660 MW HVDC Cable has been granted UDR rights but has lost its right to import capacity and therefore is modeled as being fully available to support emergency assistance in Bins 3-7, Bin 1 is modeled with 90 MW and Bin 2 is modeled with 173 MW.

(7) Energy Limited Resources

The capacity model includes Energy Limited Resources (ELRs). The NYISO filed, and FERC approved tariff changes that enhance the ability of duration limited resources to participate in the NYISO markets. These rules allow output limited resources to participate in the markets consistent with those limitations and requires owners of those resources to inform the NYISO of their elected energy output duration limitations. Effective May 1, 2021, generation resources may participate in an ELR program administered by the NYISO. Under this program, participating generators are required to submit their elected limitations to the NYISO on a confidential basis by August 1st for the upcoming Capability Year (*i.e.*, August 1, 2025 for the Capability Year beginning on May 1, 2026).

(8) Distributed Energy Resources (DER)

On April 16, 2024, the NYISO implemented the DER participation model to facilitate participation of DER in the NYISO-administered markets. Aggregated resources with different fuel types and dispatchable demand side resources (DSR) have not been previously modeled in the IRM study as a supply-side resource. A DER may be one of the following categories of facilities electrically located in the NYCA: 1) a facility comprising two or more different technology types (e.g., wind, solar) located behind a single point of interconnection with a maximum Injection Limit of 20 MW, 2) a DSR, or 3) a Generator with a maximum Injection Limit of 20 MW. The NYISO developed a participation model for DER to participate in the NYISO administered markets, including the ICAP market. Under this participation model, various resource types (including aggregations thereof) can participate in the NYISO-administered markets and will be required to follow the NYISO's dispatch instructions. With this participation model and expected enrollment of resources, two modeling principles have been established to support the modeling of different types of DER Aggregations in IRM studies:

Modeling Principle 1: Combines single resource type Aggregations that have energy duration limitations and DER Aggregations consisting of either DSR only or mixed generation resources into one unit by zone, technology type, and duration limitation.

Modeling Principle 2: Combines single resource type Aggregations without energy duration limitations by zone and technology type.

For the 2026-2027 IRM study DER totaled 480.5 MW with 480.4 MW located in Zones A through E with 0.1 MW in Zones G-I.

(9) Behind-the-Meter (BTM) Solar

Starting with the 2026-2027 IRM study, BTM solar is being modeled as a supply-side resource instead of load modifier. It is modeled as a positive DSM resource which offsets the negative DSM modeled in developing the gross load. However, the calculation for the IRM will remain unchanged. The net load will continue to be used in the denominator while the BTM solar will not be counted in the total ICAP. The output of these facilities is based on production profiles derived from existing facilities operating within the NYCA over the same five-year period that is used for conventional units.

(10) Performance Data

Performance data for thermal generating units in the model includes forced and partial outages, which are modeled by inputting a multi-state outage model that is representative of the EFORd for each unit. Generation owners provide outage data to the NYISO using Generating Availability Data System (GADS) data in accordance with the NYISO Installed Capacity Manual. The NYSRC is continuing to use a five-year historical period for the 2026 2027 IRM study.

Figure A.5 shows a rolling 5-year weighted average by zone of this data.

Figures A.6 and A.7 show the availability trends of the NYCA broken out by fuel type.

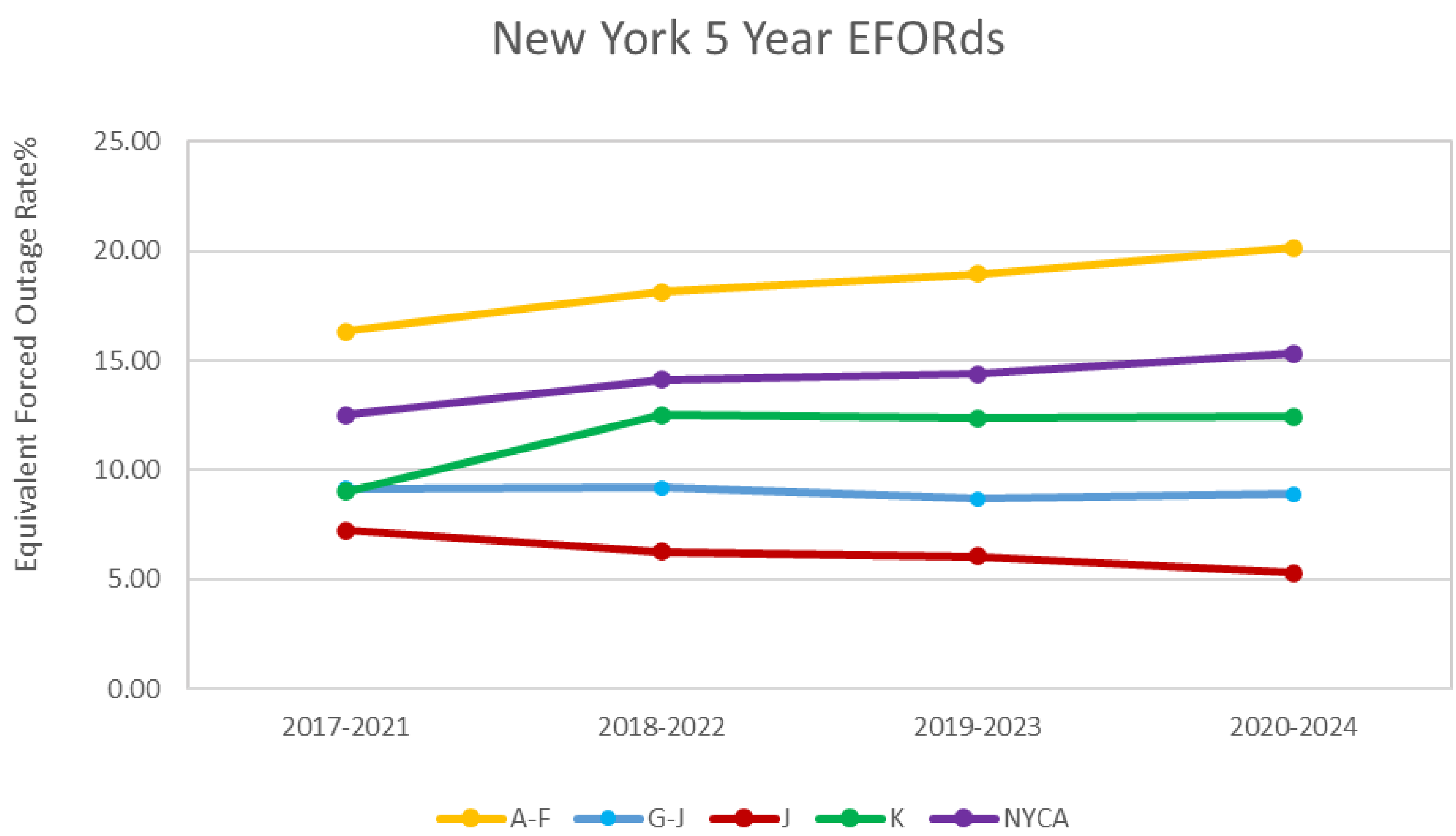
The multi-state model for each unit is derived from five years of historic events if it is available. For units with less than five years of historic events, the available years of event data for the unit is used if it appears to be reasonable. For the remaining years, the unit NERC class-average data is used.

The unit forced outage states for the most of the NYCA units were obtained from the five-year NERC GADS outage data collected by the NYISO for the years 2020 through 2024.

This hourly data represents the availability of the units for all hours. From this, full and partial outage states and the frequency of occurrence were calculated and put in the required format for input to the GE-MARS program.

Figures A.8 and A.9 show the unit availabilities of the entire NERC fleet on an annual and 5-year historical basis.

Figure A.5.a Five-Year Weighted Annual Average of Zonal EFORds



The resources included in the calculation of these values include thermal, large hydro, wind, solar, landfill gas, and run-of-river resources with CRIS. These values are the average EFORd of NYCA resources except for external resources such as UDR backing generators, firm imports, firm exports, and SCRs.

Figure A.6 NYCA Annual Weighted Average Availability

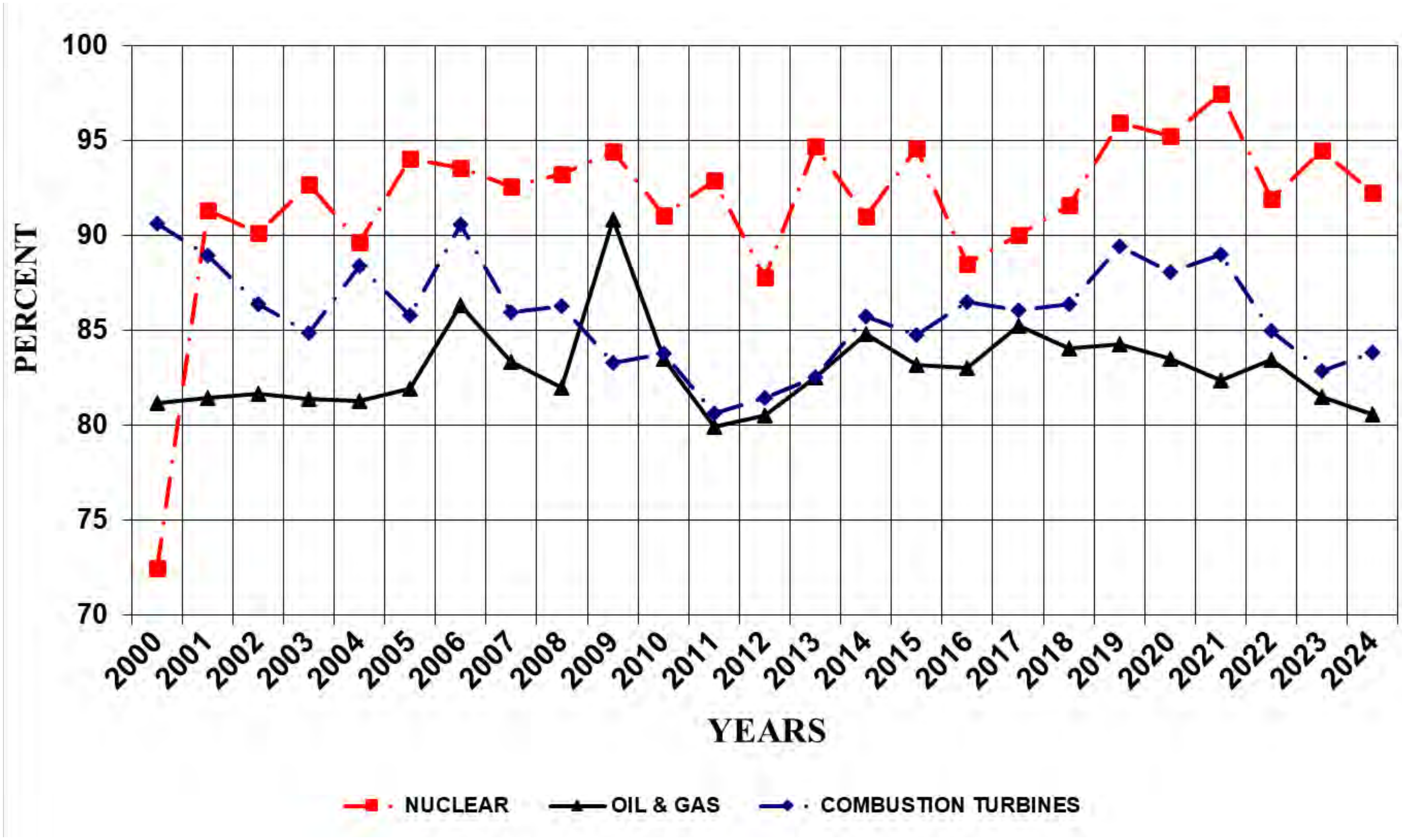


Figure A.7 NYCA Five-Year Weighted Average Availability

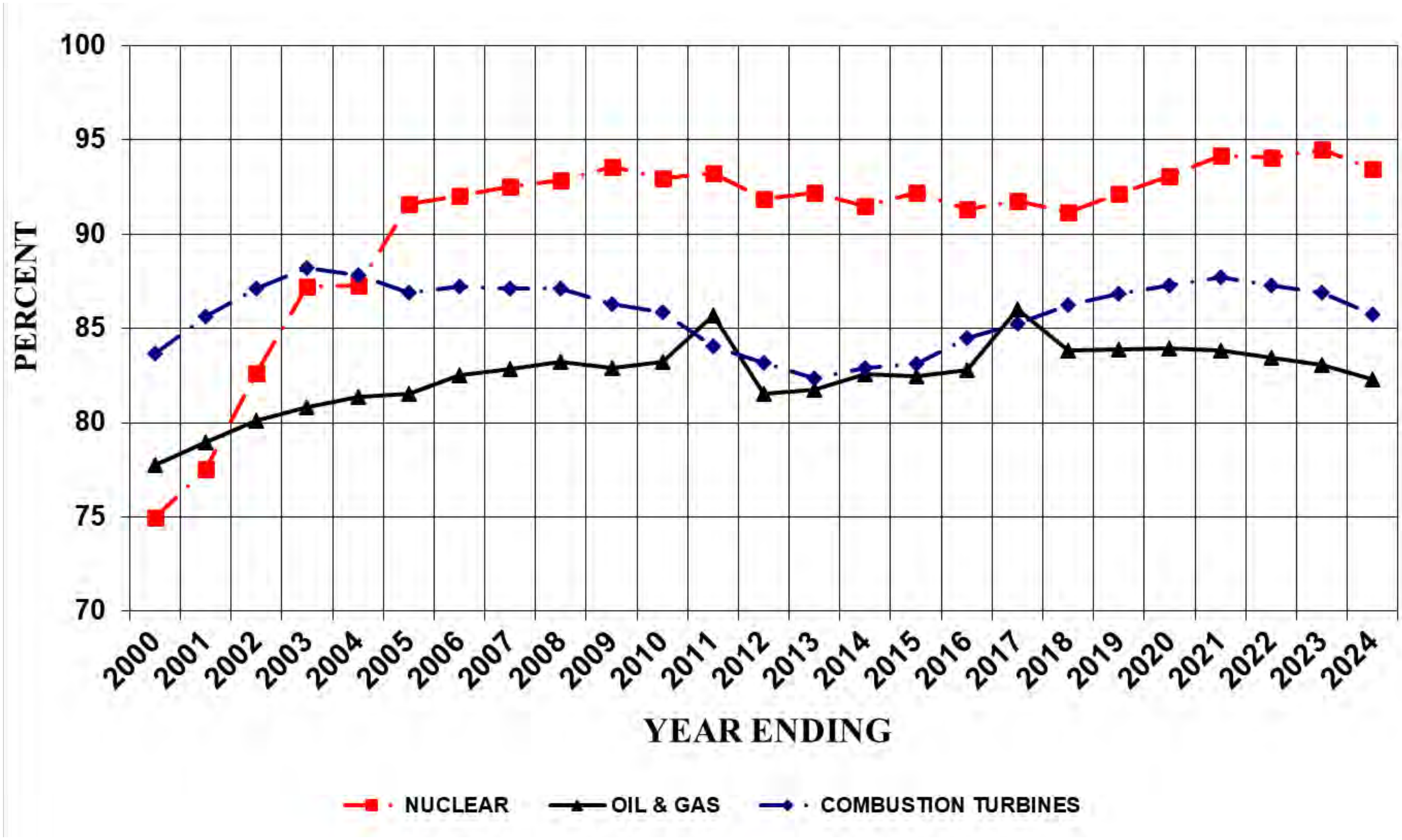
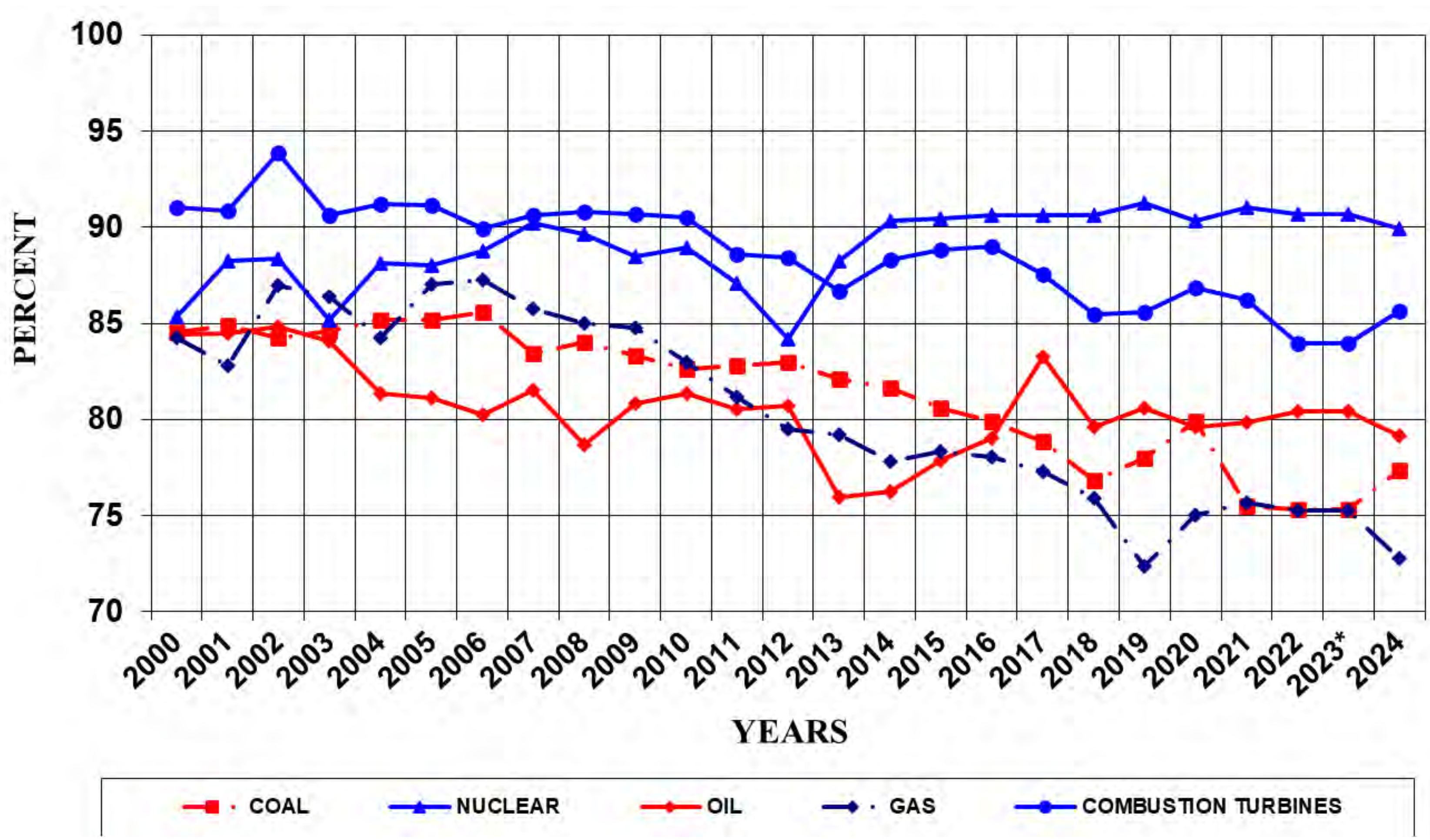
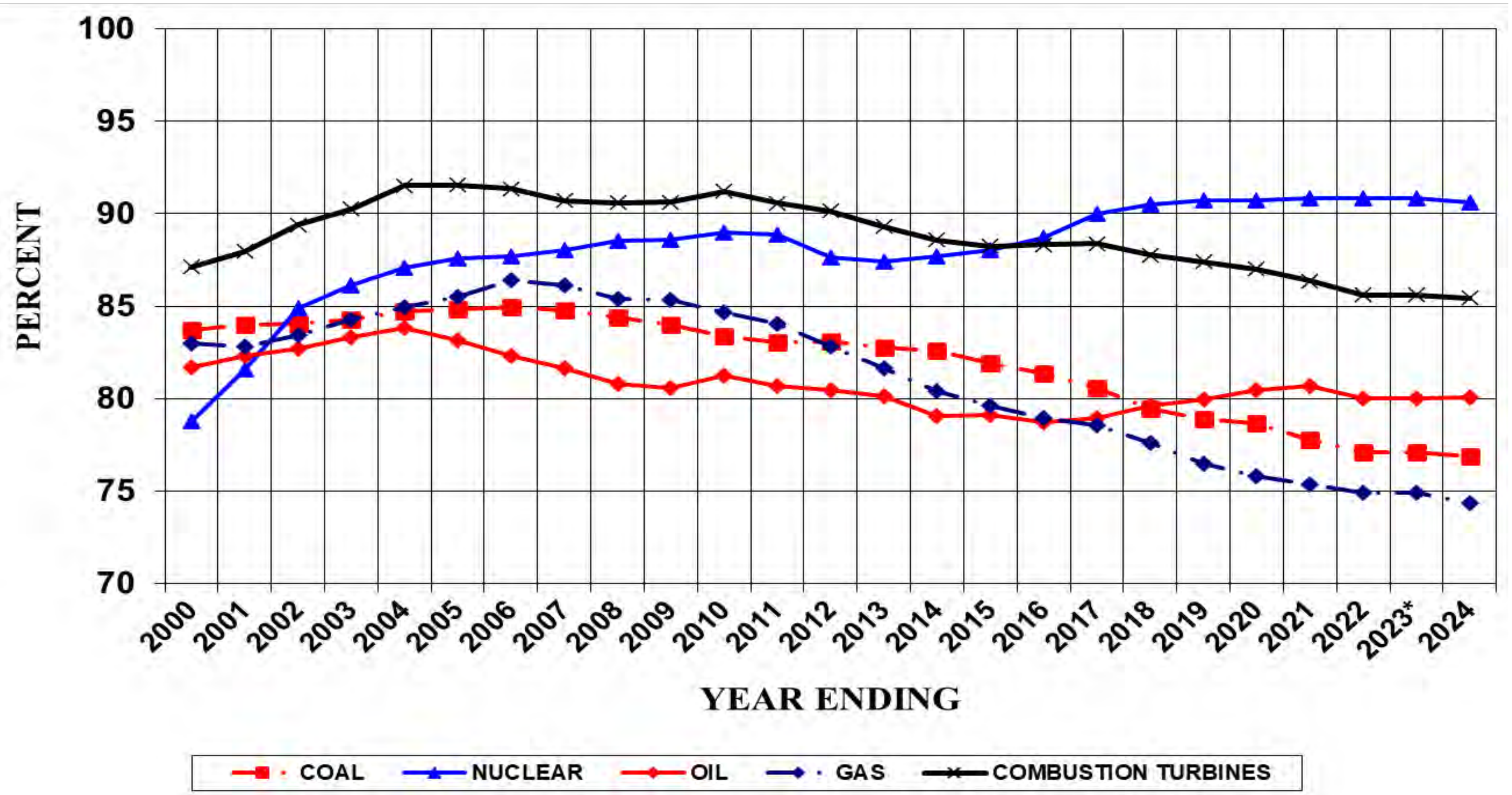


Figure A.8 NERC Weighted Annual Average Availability



*2023 NERC Class Averages were not posted by the time the FBC Assumptions were finalized. 2022 NERC Class Averages were used for 2023. Same applies to Figure A.9 2022 data was used for 2023.

Figure A.9 NERC Five-Year Weighted Average Availability



(11) Outages and Summer Maintenance

For the 2022-2023 IRM study, planned and scheduled maintenance was removed because it caused excess EOP usage. This had no impact on LOLE or IRM. Like the 2024-2025 IRM study, planned and scheduled maintenance was not modeled for the 2025-2026 IRM study and is being continued for the 2026-2027 IRM study. The nominal 50 MW of summer maintenance, however, remained constant. The amount is nominally divided equally between Load Zone J and Load Zone K.

(12) Gas Turbine Ambient De-rate

Operation of combustion turbine units at temperatures above DMNC test temperature results in reduction in output. These reductions in gas turbine and combined cycle capacity output are captured in the GE-MARS model using de-ratings based on ambient temperature correction curves. Based on the past reviews of historical data, no changes to the existing combined cycle temperature correction curves are proposed by the NYISO staff. These temperature corrections curves, provided by the Market Monitoring Unit of the NYISO, show unit output versus ambient temperature conditions over a range starting at 60 degrees F to over 100 degrees F. Because generating units are required to report their DMNC output at peak or "design" conditions (an average of temperatures obtained at the time of the transmission district previous four like capability period load peaks), the temperature correction for the combustion turbine units is derived for and applied to temperatures above transmission district peak loads.

(13) Large Hydro De-rates

Hydroelectric projects are modeled like thermal units, using a probability capacity model reflecting five years of performance data. Except in the case were an election such as ELR status would override the unit being modeled as a thermal unit. See Table A.8 above.

(14) Winter Fuel Availability Constraints

As reliability risks during the winter season become more prominent across the NYCA system, the availability of gas and oil during winter conditions will become a critical input in the IRM study. A six-tiered fuel constraint model grouped by different NYCA winter load conditions and associated constraints has been developed to capture this risk starting with the 2026-2027 Capability Year IRM Study . The winter fuel availability constraints model is intended to reflect the available fuel, from both gas and oil generating capacity in Load Zones F through K, under different NYCA load levels. This model will be reviewed and updated as needed for each IRM study cycle. Table A.11 presents the six-tiered fuel constraint model.

Table A.11 NYCA Winter Six-Tiered by Load Level Oil and Gas Fuel Availability Model

Fuel Constraint Derate by Tier*						
Tier	**NYCA Load Conditions (MW)**	**Available Gas (MW)**	**Available Oil (MW)**	**Total Available Fuel (MW) (Gas + Oil)**	**Modeled UCAP (MW)**	**Derate (%)****
1	>26,000	288	11,400	11,688	19,100	39%
2	25,000 - 26,000	575		11,975		37%
3	24,000 - 25,000	2,550		13,950		27%
4	23,000 - 24,000	4,200		15,600		18%
5	22,000 - 23,000	5,550		16,950		11%
6	<22,000	No Constraint		No Constraint		No Constraint

* Assumed values for "available gas" and "available oil" reflect adjustments to address deactivations and resources not accounted for in developing the values presented to the NYSRC Executive Committee on 4/11/2025. https://www.nysrc.org/wp-content/uploads/2025/04/4.1.2-Fuel-Availability-Constraints-Modeling-Phase-2-r1-04112025-EC-Attachment-4.1.2.pdf

** Values represent aggregate level derate. Actual derate % applied on each unit may vary.

A.3.3 Transmission System Model

A detailed transmission system model is represented in the GE-MARS topology. The transmission system topology, which includes eleven NYCA Load Zones and four External Control Areas, along with transfer limits, is shown in Figure A.10. The transfer limits employed for the 2026-2027 IRM study were developed from emergency transfer limit analyses included in various studies performed by the NYISO and based upon input from Transmission Owners and neighboring regions. The transfer limits are further refined by other assessments conducted by the NYISO. The assumptions for the transmission model included in the 2026-2027 IRM study are listed in Table A.12, which reflects changes from last year's model. The changes captured in this year's model include: 1) the Dysinger East forward limit was reduced due to load changes in Load Zone A; 2) the Central East forward limit increased with Marcy STATCOM back in service; (3) the West–Central reverse limit increased following redistribution of system flows; 4) the Moses South forward limit increased with the Smart Path Connect project modeled as in service; 5) the Sprain Brook and Dunwoodie South forward limits decreased due to pre-contingency loading tied to the Dunwoodie–Mott Haven 345 kV rating; 6) the Load Zone K- I/J export limit was reduced due to de-rate of the short-term emergency (STE) rating on the Barrett–Valley Stream circuit and higher load west of Newbridge; 7) the Load Zone K-J export limit was reduced due to the same Barrett–Valley Stream STE rating de-rate; 8) the Load Zone K-Norwalk Harbor export and import limits decreased due to a Norwalk Northport Cable (NNC) phase angel regulator (PAR) rating de-rate; 9) the Load Zone I-K export limit decreased due to the Barrett–Valley Stream STE rating de-rate and increased load west of Newbridge; and 10) the total export capability from Load Zone K toward the west ties was reduced.

Forced transmission outages are included in the GE-MARS model for the underground cables that connect New York City and Long Island to surrounding zones. The GE-MARS model uses transition rates between operating states for each interface, which were calculated based on the probability of occurrence from the most recent ten years of historic failure rates and the time to repair. Transition rates into the different operating states for each interface were calculated based on the circuits comprising each interface, including failure rates and repair times for the individual cables, and for any transformer and/or phase angle regulator associated with that cable. The applicable Transmission Owners provided updated transition rates for their associated cable interfaces.

Table A.12 Transmission System Model

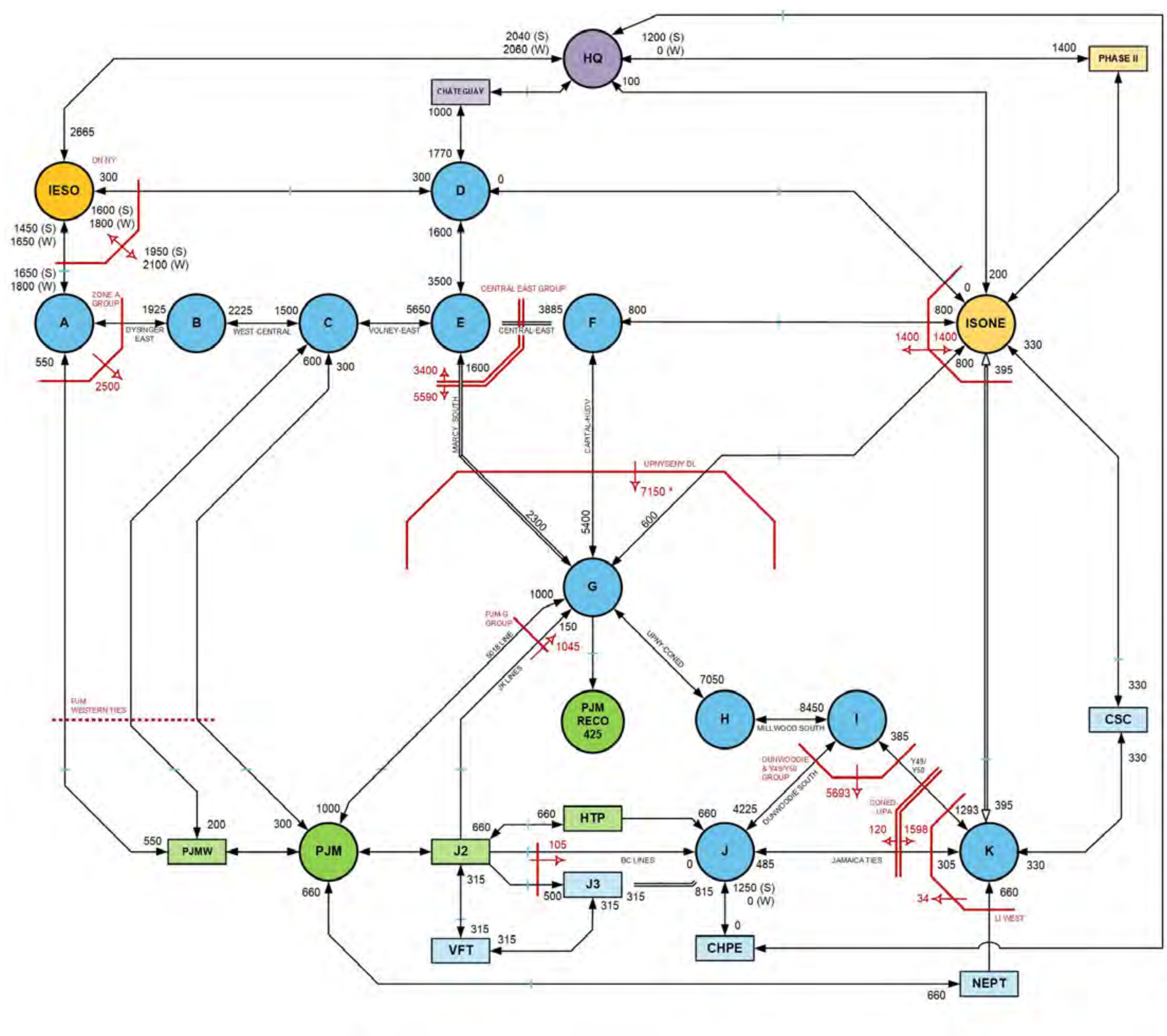
Parameter	2025-2026 Model	2026-2027 Model Assumptions Recommended	Basis for Recommendation
UPNY-ConEd Interface Limit	No modeling change from 2024-2025 IRM study assumptions	No modeling change from 2025-2026 IRM study assumptions	
West-Central NY Limits	Load Zone B to Load Zone A limit reduced to 2,200 MW	Reverse limit increased to 2,225 MW	Redistribution of flows in Load Zones A and B
Cedars Import Limit	No modeling change from 2024-2025 IRM study assumptions	No modeling change from 2025-2026 IRM study assumptions	
IESO/NYISO PARS in Zone D	No modeling change from 2024-2025 IRM study assumptions	No modeling change from 2025-2026 IRM study assumptions	
Central East and Central East + Marcy Group Transfer Limit	Central East dynamic limit table ranging from 3,810 MW to 3,385 MW	Central East dynamic limit table ranging from 3,885 MW to 3,460 MW	Marcy STATCOM is modeled as in service for the 2026-2027 IRM study
UPNY-SENY Transfer Limit	No modeling change from 2024-2025 IRM study assumptions	No modeling change from 2025-2026 IRM study assumptions	
Moses South Transfer Limit	No modeling change from 2024-2025 IRM study assumptions	Forward limit increased to 3,500 MW	Smart Path Connect project is modeled as in service for 2026-2027 IRM study

Table A.12 Transmission System Model (Continued)

Parameter	2025-2026 Model	2026-2027 Model Assumptions Recommended	Basis for Recommendation
Sprain Brook Dunwoodie South	No modeling change from 2024-2025 IRM study assumptions	Forward limit reduced to 4,225 MW	Due to Dunwoodie – Mott Haven 345 kV rating from pre-contingency loading
Load Zone K - Load Zone I/J	No modeling change from 2024-2025 IRM study assumptions	Export limit reduced to 120 MW	Derate on the Barrett to Valley Stream Circuit
Load Zone K – Load Zone I/J/PJM	No modeling change from 2024-2025 IRM study assumptions	Export limit reduced to 34 MW	Reduction is due to both the new methodology and increase in load in West LI area
Load Zone K – Load Zone I	No modeling change from 2024-2025 IRM study assumptions	Export limit reduced to 385 MW	STE de-rate on the Barrett to Valley Stream circuit and load increase in west of Newbridge region
Load Zone K – Load Zone J	No modeling change from 2024-2025 IRM study assumptions	Export Limit reduced to 485 MW	Derate on the Barrett to Valley Stream Circuit
Norwalk Harbor - Zone K Limit	No modeling change from 2024-2025 IRM study assumptions	The import and export limit was reduced to 395 MW	Due to NNC PAR derate

Table A.12 Transmission System Model (Continued)			
Parameter	2025-2026 Model	2026-2027 Model Assumptions Recommended	Basis for Recommendation
Dysinger East Transfer Limit	No modeling change from 2024-2025 IRM study assumptions	Forward limit reduced to 1,925 MW	Due to load changes in Load Zone A
Cable Forced Outage Rates	All existing Cable forced outage rates updated for NYC and LI to reflect most recent ten-year history	All existing Cable forced outage rates updated for NYC and LI to reflect most recent ten-year history	
UDR line Unavailability	Ten-year history of forced outages	Ten-year history of forced outages CHPE interface utilizing class average outage rate for existing cables	

Figure A.10 2026-2027 IRM Topology



Notes

1. PJM to NY emergency assistance (EA) assumption for calculating the PJM-NY Western ties, PJM-G Group, and ABC Line Group flow distribution limit: 1500MW
2. NYCA EA simultaneous import limit: 3,500 MW
3. External areas representation based upon information received from the NPCC CP-8 WG

Legend

- Interface
- Unidirectional Interface
- Interface w/ Dynamic Ratings
- Interface Group
- Interface Group w/ Dynamic Ratings
- Monitoring Interface Group
- NYCA EA Interface Group Marker
- XX "Dummy Bubble" i.e. no load

NOTE: An interface is considered to not have a MW limitation if no number is specified

Table A.13 shows the interface limits including dynamic limits used in the 2026 IRM study topology VS. the 2025 IRM study.

Table A.13 2026-2027 IRM Transmission Topology Interface Limits

	2025-2026		2026-2027		Delta	
Interface	**Forward**	**Reverse**	**Forward**	**Reverse**	**Forward**	**Reverse**
Load Zone A to Load Zone B	2, 100 MW	-	1,925 MW	-	+175	-
Load Zone A Export Limit	2,500 MW	-	2,500 MW	-	0 MW	-
Load Zone B to Load Zone C	1,500 MW	2,200 MW	1,500 MW	2,225 MW	0 MW	+25 MW
Load Zone E to D	2,650 MW	1,600 MW	3,500 MW	1,600 MW	+850 MW	0 MW
Chateauguay to Load Zone D	1,770 MW	1,000 MW	Summer: 1,770 MW Winter: varied by month	1,000 MW	Summer: 0 MW Winter: varied by month	0 MW
Central East	3,810/3,730/ 3,650/3,565/ 3,465/3,385 MW	-	3,885/3,805/ 3,725/3,640/ 3,540/3,460 MW	-	+75/+75/+75/+ 75+75/+75	-
Central East + Marcy Group	5,590/5,475/5 ,360/5,235/5, 080/4,945 MW	-	5,590/5,475/5,3 60/5,235/5,080 /4,945 MW	-	0 MW	-
UPNY-SENY	7,150 MW. No dynamic limits	-	7,150 MW. No dynamic limits	-	0 MW	-
Load Zone K to Load Zones I and J Group	1,598 MW	170/170/1 5 MW	1,598 MW	120/110/0 MW	0 MW	-50/-60/-15 MW
Sprain Brook Dunwoodie South	4,400 MW	-	4,225 MW	-	-175 MW	-
Load Zone K to Load Zone J	505 MW	305 MW	485 MW	305 MW	-20 MW	0 MW

Table A.13 IRM Transmission Topology Interface Limits (continued)

	2025-2026		2026-2027		Delta	
Interface	**Forward**	**Reverse**	**Forward**	**Reverse**	**Forward**	**Reverse**
Load Zone K to Load Zone I/J/PJM Group	84 MW	-	34 MW	-	-50 MW	0 MW
Norwalk Harbor to Load Zone K	404 MW	414 MW	395 MW	395 MW	-9 MW	-19 MW
Load Zone K to Load Zone I	460 MW	1,293 MW	385 MW	1,293 MW	-75 MW	0 MW
Load Zone J to J3	315 MW	425/700/815/ 750/750/ 815 MW	315 MW	425/700/815 / 750/750/ 815 MW	0 MW	0 MW

The Topology for the 2026-2027 IRM study features the following changes from the 2025-2026 IRM study:

1. **Update to Central East Forward Limit due to Marcy STATCOM Return to Service:** The Central East voltage collapse limit was increased from 3,810 MW to 3,885 MW; each dynamic limit is also increased by 75 MW. The Central-East Voltage Limit Study (CEVC 2023) provides the voltage collapse limit for the Central East interface under different system conditions. This data identifies a 75 MW derate for an outage of the Marcy STATCOM for all Oswego Complex combinations. The proposed Central East forward transfer limits remove the prior 75 MW derate resulting in dynamic limits that align with the Oswego Complex limits in the 2023 Central-East Voltage Study report with the Marcy STATCOM modeled as in service.

2. **Update to the West Central Reverse Limit:** The West Central reverse limit was increased from 2,200 MW to 2,225 MW. This update is driven by redistribution of flows.

3. **Update to Dysinger East Forward Limit:** The Dysinger East forward limit decreased from 2100 MW to 1925 MW. This change is driven by changes in load pattern in Load Zone A

4. **Update to Moses South Forward Limit due to Smart Path Connect Project:** The Moses South Forward Limit increased from 2,650 MW to 3,500 MW. The 2025 NYISO Summer Operating Study does not incorporate the Smart Path Connect Project and therefore does not reflect this higher limit. The updated thermal limit was established to more accurately represent the system topology with the Smart Path Connect Project modeled as in-service, which better aligns with the expected configuration for the 2026–2027 Capability Year.

5. **Update to Sprain-Brook Dunwoodie-South Forward Limit:** The Sprain Brook and Dunwoodie South forward limit decreased from 4,400 MW to 4,225 MW due to the Dunwoodie- Mott Haven 345kV rating from pre-contingency loading.

6. **Update to Load Zone K – Load Zone I/J Export Limit (Total NYISO Export):** The export limit from Load Zone K to Load Zones I/J has been reduced from 170 MW to 120 MW under all lines in-service conditions. This update was provided by PSEG Long Island as part of their annual transmission study. The reduction in transfer capability is primarily attributed to an STE rating de-rate on the Barrett–Valley Stream circuit and an increase in load in the West of Newbridge region. The dynamic limits, which vary based on the operational status of the Barrett 1 and 2 generating units, also decreased by approximately 30–60 MW.

7. **Update to Load Zone K- Load Zone J Export Limit (Total Jamaica Export):** The export limit from Load Zone K to Load Zones J reduced from 505 MW to 485 MW for all lines in-service condition. This update was provided by PSEG Long Island as part of their annual transmission study. The reduction in transfer capability is a result of an STE rating de-rate on the Barrett–Valley Stream circuit. The dynamic limits, which vary based on the operational status of the Barrett 1 and 2 generating units, have decreased by 20 MW as well.

8. **Update to Load Zone K- Norwalk Harbor Export Limit (NNC Export):** The Load Zone K to Norwalk Harbor export limit decreased from 414 MW to 395 MW. These updates were provided by PSEG Long Island as part of their annual transmission study. The reduction is due to NNC PAR de-rate.

9. **Update to Norwalk Harbor -– Load Zone K Import Limit (NNC Import):** Norwalk Harbor to Zone K import limit decreased from 404 MW to 395 MW. This update was provided by PSEG Long Island as part of their annual transmission study. The reduction is due to NNC PAR de-rate.

10. **Update to Load Zone I – Load Zone K Export Limit (Y49-Y50):** The export limit between Load Zone I and Load Zone K decreased from 460 MW to 385 MW. This update was provided by PSEG Long Island as part of their annual transmission study. The reduction in transfer capability is primarily attributed to an STE rating de-rate on the Barrett–Valley Stream circuit and an increase in load in the West of Newbridge region.

11. **Update to Load Zone K- Load Zone I/J/PJM Export Limit (Total Export towards West Ties):** The total export limit towards west ties reduced from 84 MW to 34 MW. This update was provided by PSEG Long Island as part of their annual transmission study.

A.3.4 External Area Representations

NYCA reliability depends in part on emergency assistance (EA) from its interconnected Control Area neighbors (New England, Ontario, Quebec and PJM) based on reserve sharing agreements with these external Control Areas. Load and capacity models of these areas are therefore represented in the GE-MARS analyses with data received directly from the areas and through NPCC sources.

The primary consideration for developing the final load and capacity models for the external Control Areas is to avoid over-dependence on the external Control Areas for emergency capacity support.

For this reason, a limit is placed on the amount of emergency capacity support that the NYISO can receive from external Control Areas in the IRM study. The 2023-2024 IRM study the limit was 3,500 MW for all LFU bins. For the 2024-2025 IRM study, the EA limit was updated to vary by LFU bin or load level. Based on a study and recommendation from the NYISO[4] that considered the amount of extra reserves that are available in the external Control Areas above each area's required operating reserve by load level, the 3,500 MW limit was modified as follows: LFU Bin 1: 1,470 MW; LFU Bin 2: 2,600 MW; LFU Bin 3-7: 3,500 MW. Also, Interface limits between the NYISO and neighboring external Control Areas were adjusted such that the total EA from all external Control Areas does not exceed the EA limit by LFU Bin. During the 2025-2026 IRM study, the dynamic emergency assistance modeling was expanded to include the HVDC lines to reflect the proportional limits to emergency assistance from the external control areas. For the 2026-2027 IRM study, the emergency assistance limit from Quebec was decreased to 0 MW during the winter season (November – April).

[4] See Installed Capacity Subcommittee Meeting No. 278 — June 28, 2023 – NYSRC **Agenda Item 9 "**EOP Review Whitepaper Update" and Installed Capacity Subcommittee Meeting No. 279 — August 2, 2023 **Agenda Item 13 "**EOP Whitepaper Preliminary Recommendations for study details".

In addition, an external Control Area's LOLE assumed in the IRM study cannot be lower than its LOLE criteria and its reserve margin can be no higher than its minimum requirement. If an external Control Area's reserve margin is lower than its requirement and/or its LOLE is higher than its criterion, pre-emergency demand response can be represented. In other words, the neighboring external Control Areas are assumed to be equally or less reliable than NYCA.

Another consideration for developing models for the external Control Areas is to recognize internal transmission constraints within the external Control Areas that may limit emergency assistance to the NYCA. This recognition is considered implicitly for those external Control Areas that have not supplied internal transmission constraint data. Additionally, EOPs are removed from the external Control Area models.

Finally, the top three summer peak load days of an external Control Area should be specified in the load model to be coincident with the NYCA top three peak load days. The purpose of this is to capture the higher likelihood that there will be considerably less load diversity between the NYCA and external Control Areas on the hot summer days.

For this study, both New England and PJM continue to be represented as multi-area models, based on data provided by these Control Areas. Ontario and Quebec are represented as single area models. The load forecast uncertainty model for the outside world model was supplied from the external Control Areas. PJM is no longer updating their MARS model for NPCC and therefore remains unchanged from the 2025-2026 IRM study in the 2026-2027 IRM Study.

Modeling of the neighboring Control Areas in the base case in accordance with Policy 5-1919 is as follows:(see Table A.14 top of next page)

Table A.14 External Area Representations

Parameter	2025-2026 Study Assumption	2026-2027 Study Assumption	Explanation
Capacity Purchases	Grandfathered amounts: PJM – 1,013 MW HQ – 1,190 MW All contracts modeled as equivalent contracts	Grandfathered amounts: PJM – 1,080 MW HQ – 1,190 MW in Summer, Varied (0 – 914 MW) in Winter All contracts modeled as equivalent contracts	Grandfathered Rights, Existing Transmission Capacity for Native Load (ETCNL), and other awarded long-term rights.
Capacity Sales	Long term firm sales of 266.6 MW (Summer)	Long term firm sales of 266.7 MW (Summer)	Long-term contracts.
External Area Modeling	Single Area representations for Ontario and Quebec. Five areas modeled for PJM. Thirteen zones modeled for New England	Single Area representations for Ontario and Quebec. Five areas modeled for PJM. Thirteen zones modeled for New England	The load and capacity data are provided by the neighboring areas. This updated data may then be adjusted as described in Policy 5. PJM is no longer updating their MARS model for NPCC.
Reserve Sharing	All NPCC Control Areas have indicated that they will share reserves equally	All NPCC Control Areas have indicated that they will share reserves equally	Per NPCC CP-8 working group assumption.

Table A.15 top of next page shows the final reserve margins and LOLEs for the Control Areas external to NYCA. The 2025 external area model was updated from 2024 but with a modified MW limit for emergency assistance imports during any given hour as described above. As per Table 7-1 of the IRM study report, the difference between the isolated case and the final base case was 4.78% in the 2026-2027 IRM study compared to 5.5% in the 2025-2026 IRM study.

Table A.15 Outside World Reserve Margins

Area	2025-2026 Study Reserve Margin	2026-2027 Study Reserve Margin	2025-2026 Study LOLE (Event-Days/Year)	2026-2027 Study LOLE (Event-Days/Year)
Quebec	8.4%	10.5%	0.103	0.136
Ontario	5.1%	11.5%	0.126	0.119
PJM	16.1%	15.2%	0.120	0.117
New England	5.8%	12.7%	0.107	0.164

A.3.5 Emergency Operating Procedures (EOPs)

There are many steps that the system operator can take in an emergency to avoid disconnecting load. EOP steps 2 through 10 listed in Table A.17 were provided by the NYISO based on operator experience. Table A.16 lists the assumptions modeled.

The values in Table A.16 are based on a NYISO forecast that incorporates 2024 (summer) operating results. This forecast is applied to a 2026 peak load forecast of 31,648.2MW. The table shows the most likely order that these steps will be initiated. The actual order will depend on the type of the emergency. The amount of assistance that is provided by EOPs related to load, such as voltage reduction, will vary with the load level.

Table A.16 Assumptions for Emergency Operating Procedures

Parameter	2025-2026 Study Assumption	2026-2027 Study Assumption	Explanation
Special Case Resources	July 2024 – 1,486.7 MW based on registrations and modeled with maximum capacity of 1,280.8 MW derated by hourly response rates. Utilize a new energy limited resource (ELR) functionality to model SCRs as duration limited resources with hourly response rates and limited to one call per day. Monthly variation based on historical experience.	July 2025 – 898.1 MW based on registrations and modeled with maximum capacity of 724.2 MW derated by hourly response rates. Output limitations will be lifted 3 hours prior to the preliminary base case weighted average summer peak net load hour for Load Zones A-F (HB16) and G-K (HB14).	Summer values calculated from July 2025 registrations accounting for updated historical performance. Also accounts for the transition of resources from the SCR program to the DER participation model. SCRs transitioning to the DER participation model and represented as DER for the 2026-2027 IRM study have been removed from the SCR values.
Other EOPs	400 MW of 10-min reserves maintained at load shedding Voluntary Curtailment and Public Appeals are limited to 3 calls per year.804.6 MW of non-SCR/non-EDRP resources	400 MW of 10-min reserves maintained at load shedding Voluntary Curtailment are limited to 3 calls per month. Public Appeals are limited to 3 calls per year. 866.8 MW of non-SCR/non-EDRP resources	Based on Whitepaper and NYISO updated analysis recommendation Based on TO information, measured data, and NYISO forecasts

Table A.16 Continued on Next Page

Parameter	2025-2026 Study Assumption	2026-2027 Study Assumption	Explanation
EOP Structure	10 EOP Steps Modeled	10 EOP Steps Modeled	Based on ICS recommendation

Table A.17 Emergency Operating Procedures Values

Step	Procedure	2025-2026 IRM MW Value	2026-2027 IRM MW Value
1	Special Case Resources – Load, Gen	1,486.7 MW Enrolled/ Varies Hourly 1,280.8 MW Max Capacity Modeled	898.1 MW Enrolled / 724.15 MW Modeled
2	5% manual voltage Reduction	63.38 MW	64.58 MW
3	Thirty-minute reserve to zero	655 MW	655 MW
4	Voluntary industrial curtailment	260.74 MW (limited to 3 calls per year)	267.12 MW (limited to 3 calls per month)
5	General Public Appeals	74 MW (limited to 3 calls per year)	74 MW (limited to 3 calls per year)
6	5% remote voltage reduction	406.49 MW	461.06 MW
7	Emergency Purchases	Varies	Varies
8	Ten-minute reserves to zero	910 MW (400 MW maintained at load shedding)	910 MW (400 MW maintained at load shedding)
9	Customer disconnections	As needed	As needed
10	Adjustment used if IRM is lower than technical study margin	As needed	As needed

A.3.6 Locational Capacity Requirements

The GE-MARS model used in the IRM study provides an assessment of the adequacy of the NYCA transmission system to deliver assistance from one Load Zone to another for meeting load requirements. Previous studies have identified transmission constraints into certain Load Zones that could impact the LOLE of these Zones, as well as the statewide LOLE. To minimize these potential LOLE impacts, these Load Zones require a minimum portion of their NYCA ICAP requirement, *i.e.,* locational ICAP, to be met by resources that be electrically located within the Load Zone to ensure that enough energy and capacity are available in that Zone and that NYSRC Reliability Rules are met. For the purposes of the IRM study, locational ICAP requirements are applicable to two transmission-constrained Load Zones, New York City and Long Island, and are normally expressed as a percentage of each Zone's annual peak load.

These locational ICAP requirements, recognized by NYSRC Reliability Rule A.2 and monitored by the NYISO, supplement the statewide IRM requirement. This report using the unified methodology determines the minimum locational requirements for different levels of installed reserve. The NYSRC chooses the IRM to be used for the coming year and the NYISO chooses the final value of the locational requirements to be met by the LSEs.

A.3.7 Special Case Resources (SCRs)

SCRs are loads capable of being interrupted, and distributed generators, rated at 100 kW or higher, that are not directly telemetered. SCRs are ICAP resources that only provide energy/load curtailment when activated in accordance with the NYISO Emergency Operating Manual. Performance factors for SCRs are shown in Table A.18.

Table A.18 SCR Performance

SCR Performance for 2026-2027 IRM Study									
Super Zones	SCR Enrollments (MW)	Response Rate (%) by Hour of SCR Activation							Superzonal ACL to CBL Translation Factor (%)
		Event Hour 1	Event Hour 2	Event Hour 3	Event Hour 4	Event Hour 5	Event Hour 6	Event Hour 7	
A - E	260.5	82.33%	85.85%	85.54%	79.20%	75.61%	0%	0%	91.85%
F	87.8	72.95%	79.54%	82.43%	83.29%	83.40%	70.40%	66.99%	89.18%
G - I	73.9	61.08%	69.85%	72.12%	73.52%	74.47%	71.50%	0%	83.46%
J	453.0	57.53%	62.61%	66.97%	70.70%	72.29%	66.09%	0%	72.92%
K	23.1	51.20%	57.99%	63.12%	65.49%	64.82%	63.35%	52.63%	75.13%
All Zones	898.1	66.77%	72.08%	74.61%	74.35%	73.83%	66.38%	58.14%	

Table A.18 note 1: The SCR performance for 2026-2027 IRM study reflects the "Enhanced SCR Modeling" construct.[5] The introduction of this modeling construct starting with the 2025-2026 IRM study increased the significance of the output window and highlighted the need for differentiated start times based on historical activation data and regional peak load profiles. The Phase 1 ELR whitepaper efforts developed a new methodology to define SCR start times based on peak net load for the summer.[6] This methodology was adopted into the 2026-2027 IRM Final Base Case (FBC). The start time for SCRs in Load

[5] https://www.nysrc.org/wp-content/uploads/2024/01/SCR-Modeling-ICS-01302024-Market-Sensitive27154.pdf
[6] https://www.nysrc.org/wp-content/uploads/2025/11/ELR-Phase-2-Whitepaper-ICS11112025-Draft-v2-clean.pdf

Zones A-F changed from HB14 to HB16 while the start time for SCRs located in Load Zones G-K remained at HB14.

GE-MARS model accounts for SCRs as an EOP step and will activate this step before degrading 30-minute reserve capability consistent with the rules for when the program is activated. Both GE-MARS and NYISO operations only activate EOPs in zones where they are capable of being delivered.

SCRs are modeled with monthly values. The registered value is 898.1 MW. An effective value of 724.2 MW is used in the model. Summer values calculated from July 2025 registrations accounting for updated historical performance. The values also account for the transition of resources from the SCR program to the Distributed Energy Resource (DER) participation model. SCRs transitioning to the DER participation model and represented as DER for the 2026-2027 IRM study have been removed from the SCR values.

A.4 Data Scrub

A.4.1 GE Data Scrub

General Electric (GE) was asked to review the input data for errors. GE performs a "Data Scrub" which processes the input files and flags data that appears to be out of the ordinary. For example, it can identify a unit with a forced outage rate significantly higher than all the others in that size and type category. If something is found, the NYISO reviews the data and confirms that it is the right value as is or institutes an update. The results of this data scrub are shown in Table A.19 for the preliminary base case.

Table A.19 GE MARS Data Scrub

Item	Description	Disposition	Data Change	Parametric Effect
1	8 units had changes in capacity that exceeded 10 MW; 9 units were identified with greater than 5% EFORd changes	These changes were part of larger annual update, and confirmed to be correct	N	N/A
2	18 interface limits were found to be inconsistent between the model database and the Assumptions Matrix	Inconsistencies caused by modeling of contracts along the interfaces; Database and Assumptions Matrix confirmed to be correct	N	N/A
			Total	0.00

A.4.2 NYISO Data Scrub

The NYISO also performs a review of the MARS data independently from GE. The result of this review is listed below

Table A.20 NYISO Data Scrub

Item	Description	Disposition	Data Change	Parametric Effect
1	The NYISO found no MARS data issues to report	No issues to report	N	N/A
			Total	0.00

A.4.3 Transmission Owner Data Scrub

In addition to the above reviews, two transmission owners scrub the data and assumptions using a masked database provided by the NYISO. Their findings are listed below.

Table A.21 Transmission Owner Data Scrub

Item	Description	Disposition	Data Change	Parametric Effect
1	Transmission owners found no MARS data issues to report	no issues to report	N	N/A
			Total	0.00

Appendix B

Details of Study Results

B. Details for Study Results – Appendix B

B.1 Implementing Emergency Operating Procedures

In addition to SCRs, the NYISO will implement several other types of EOPs, such as voltage reductions, as required, to avoid or minimize customer disconnections. Projected 2025 EOP capacity values are based on recent actual data and NYISO forecasts. SCR calls were limited to 1 call per day; voluntary load curtailment are limited to 3 calls per month and public appeals are limited to 3 calls per year. Table B.1 below presents the expected EOP frequencies for the 2026-2027 Capability Year, assuming the 25.3% base case IRM with ELR modeling.

Table B.1 Implementation of EOP steps

Step	EOP	Expected Implementation (Days/Year)	
		IRM 2026-2027 PBC Tan45	IRM 2026-2027 FBC Tan45
1	Require SCRs (Load and Generator)	7.5	6.3
2	5% manual voltage reduction	6.3	5.3
3	30-minutes reserve to zero	6.1	5.1
4	Voluntary load curtailment	4.4	3.2
5	Public appeals	4.2	2.7
6	5% remote controlled voltage reduction	4.1	2.6
7	Emergency purchases	3.4	2.1
8	10-minutes reserve to 400 MW	0.2	0.2
9	Customer disconnections	0.1	0.1

Note: The expected implementation days per year reported in each Emergency Operating Procedure (EOP) step are the expected number of days that MARS calls for that EOP step. If an EOP step has a limitation on the number of days that it can provide relief, such as the 3 calls per year for Public Appeals or 3 calls per month for Voluntary Curtailment, it will provide no load relief after the 3rd call. Special Case Resources (SCRs) are modeled utilizing a duration limitation with hourly response rates and a 1 call per day limitation.

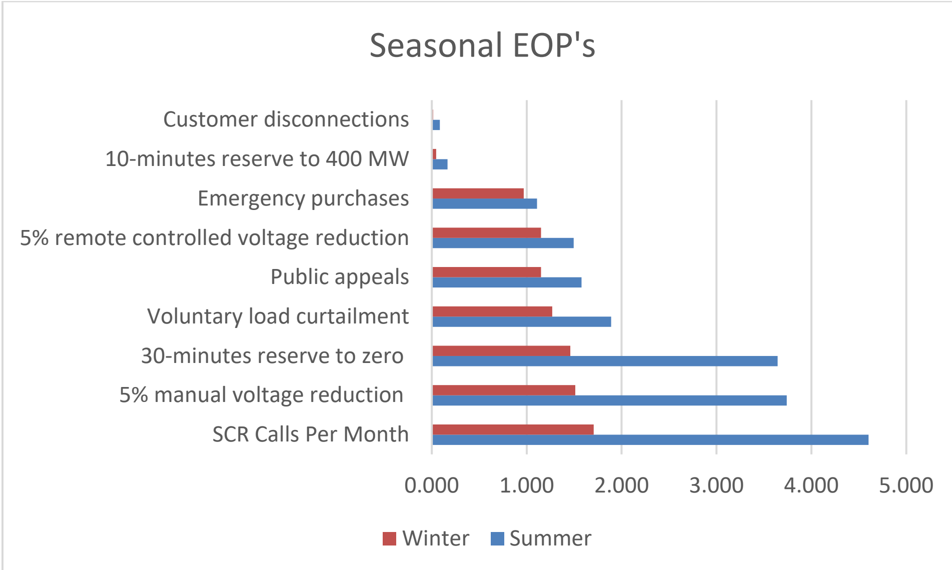
Table B.2 presents EOP calls by months and season and Figure B.3 shows the seasonal results graphically. While the final "Customer Disconnects" shows roughly 14% of the risk occurring in the winter, some of the other EOP's show almost 50% of the risk in the winter months. This represents a significant shift from previous years.

Table B.2 EOP Calls Per Month

	SCR Calls Per Month	5% manual voltage reduction	30-minutes reserve to zero	Voluntary load curtailment	Public appeals	5% remote controlled voltage reduction	Emergency purchases	10-minutes reserve to 400 MW	Customer disconnections
Month	Days/Month								
JAN	1.208	1.068	1.029	0.893	0.805	0.805	0.679	0.029	0.009
FEB	0.111	0.088	0.084	0.065	0.054	0.054	0.039	0.002	0.000
MAR	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
APR	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
MAY	0.001	0.001	0.001	0.000	0.000	0.000	0.000	0.000	0.000
JUN	0.087	0.072	0.070	0.018	0.012	0.011	0.007	0.001	0.001
JUL	1.648	1.389	1.348	0.806	0.719	0.695	0.561	0.130	0.065
AUG	1.940	1.588	1.555	0.754	0.611	0.565	0.399	0.025	0.015
SEP	0.926	0.690	0.669	0.311	0.236	0.224	0.142	0.010	0.005
OCT	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
NOV	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
DEC	0.387	0.356	0.347	0.310	0.291	0.291	0.250	0.015	0.005

	SCR Calls Per Month	5% manual voltage reduction	30-minutes reserve to zero	Voluntary load curtailment	Public appeals	5% remote controlled voltage reduction	Emergency purchases	10-minutes reserve to 400 MW	Customer disconnections
Summer	4.602	3.740	3.643	1.889	1.578	1.496	1.108	0.166	0.085
Winter	1.706	1.512	1.460	1.268	1.151	1.151	0.969	0.046	0.014
Annual	6.309	5.252	5.104	3.158	2.729	2.646	2.077	0.212	0.099

Figure B.1 Seasonal EOP Calls

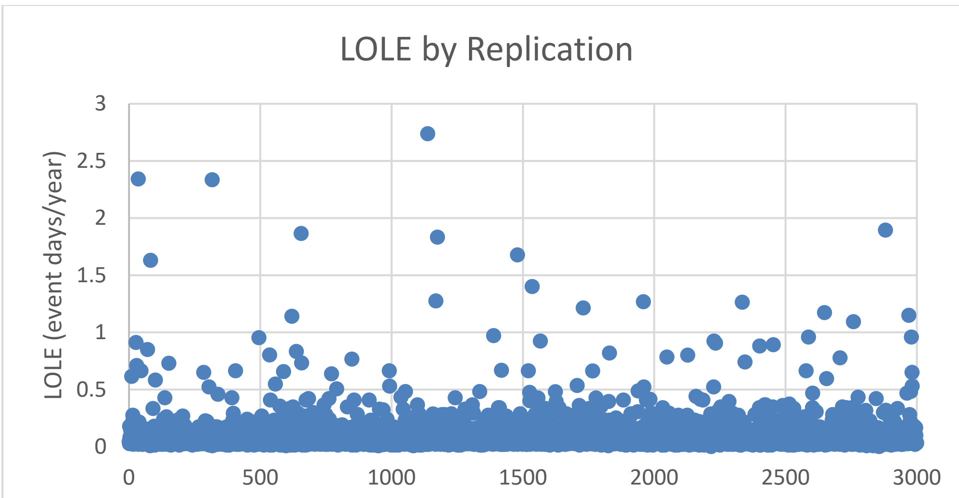


B.2 Review of LOLE Results and Additional Reliability Metrics

B.2.1 Review of LOLE Results

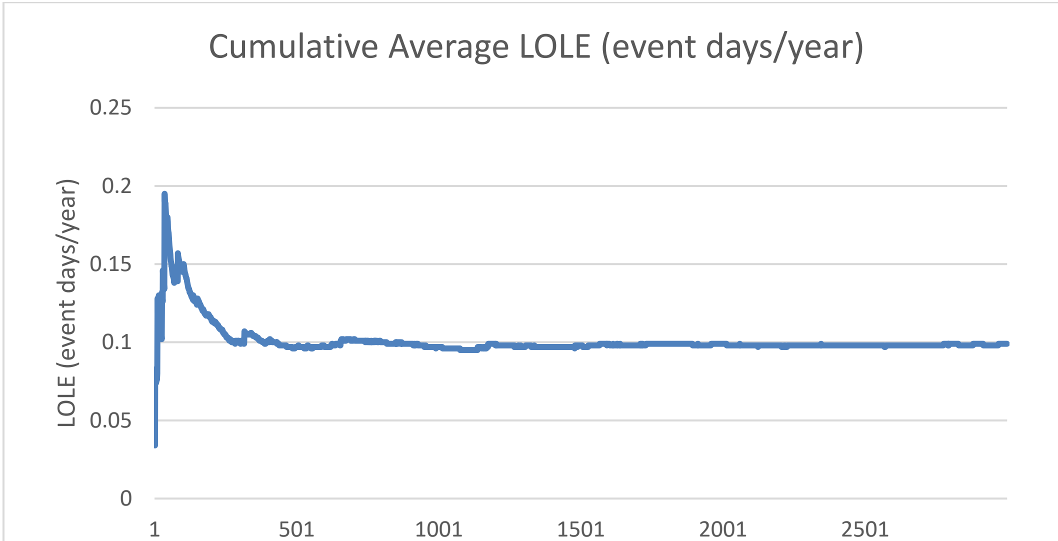
By design, the 2026-2027 IRM study final base case (FBC) had an average Loss of Load Expectation (LOLE) of 0.100 events/year. However, that doesn't tell the whole story. The Monte Carlo logic simulated the system for 3,000 replication years and the annual values ranged from a minimum of 0.006 events/year to a maximum of 3.242 events/year. The figure B.2 below shows the value of the LOLE for each of the replication years.

Figure B.2 Value of LOLE by Replication Year



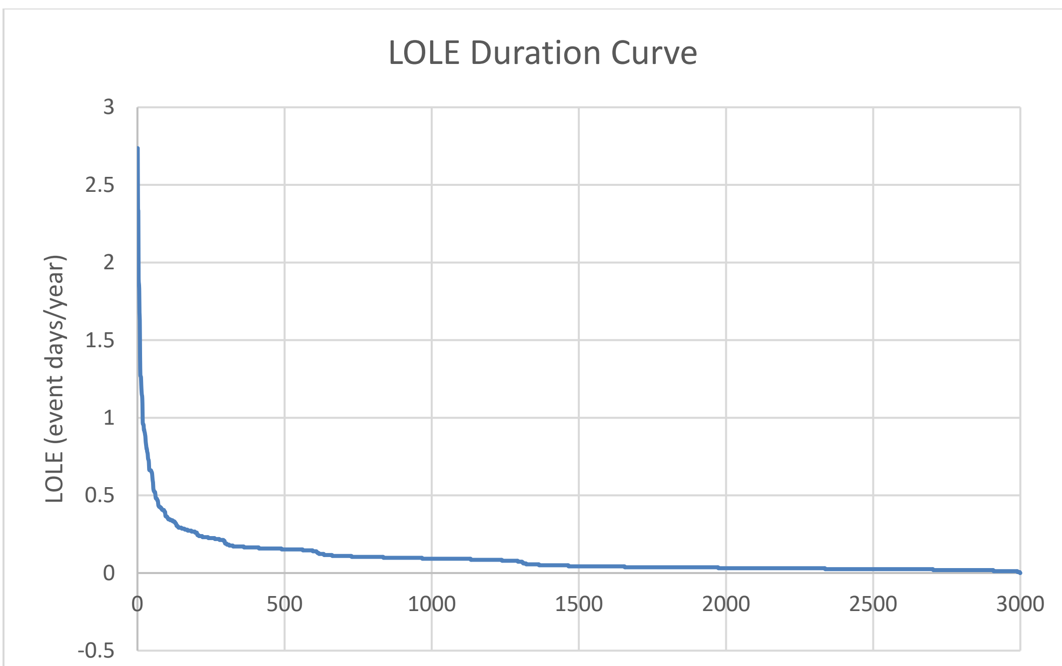
The next curve, figure B.3 top of next page shows the cumulative average over the course of the replications. After some initial fluctuations the value can be seen to settle out after about 500 replications and is fairly constant after 1,250 replications.

Figure B.3 LOLE Cumulative Average Over Replication Years



The Figure B.4 below shows a duration curve of the 3,000 values. While the average value is 0.100 there are hundreds of replications where the value was much higher.

Figure B.4 LOLE Duration Curve



B.2.2 Additional Metrics

In addition to calculating the LOLE in Event-days/year the model also calculated the Hourly Loss of Load Expectation (HLOLE) in Event-hours/year and the Expected Unserved Energy (EUE) in MWH/year. In addition, the expected Duration in hours/event can be determined by dividing the HLOLE by the LOLE and the expected Magnitude in MW/event can be calculated as EUE/HLOLE. The table below shows the minimum, maximum and average values for these metrics. Although the average duration of outages was roughly 3.7 hours, events of over 11 hours occurred.

Table B.3 Additional Metrics

3000 Replications	Minimum	Maximum	Average
LOLE (event days/year)	0	2.74	0.10
HLOLE (event hours/year)	0	10.35	0.36
LOEE (MWh/year)	0	2849.94	169.51
Duration (Hours/event)	0	11.01	3.71
Magnitude (MW/event)	0	1292.14	509.44

The table B.4 below shows the results broken down by weather year. Although the average LOLE over all of the replications was 0.100 Event-Days/year there were variations by Weather Year. This database uses the last five years of operating history.

Table B.4 Results by Weather Year

Weather Year	Count	Minimum	Maximum	Average
2020	635	0.019	1.864	0.111
2021	607	0.006	2.341	0.106
2022	595	0.000	1.677	0.086
2023	594	0.006	2.737	0.100
2024	569	0.000	1.400	0.092

B.2.3 Conclusions

Although these supplemental metrics add important new insights into the reliability of the system, the range of the values across all of the replications adds an even greater dimension. It will be important to calculate not only these new metrics in future studies, but also the distribution of the values for base cases and sensitivities.

B.3 Review of EUE and NYCA Risk Profiles by Zone and Locality

B.3.1 Expected Unserved Energy (EUE) for the NYCA and Localities

The table B.5 shows the monthly Expected Unserved Energy (EUE) in megawatt-hours (MWh) for the 2026-2027 IRM Study final base case (FBC). The color shading indicates the EUE magnitude, where darker red represents higher values and white represents zero values (i.e., no EUE). The month of July exhibits the highest values, with significant contributions from Load Zones J and K (over 40 MWh each). However, the presence of notable EUE in January is evidence of emerging winter risks.

Table B.5 Monthly EUE

Monthly EUE (MWh/month)

	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
NYCA	14.110	0.272	0.000	0.000	0.000	0.159	140.340	7.712	1.530	0.000	0.000	5.384
ROS	4.953	0.105	0.000	0.000	0.000	0.000	25.503	0.015	0.000	0.000	0.000	1.928
GHI	3.907	0.080	0.000	0.000	0.000	0.000	28.062	0.014	0.000	0.000	0.000	1.405
J	5.251	0.087	0.000	0.000	0.000	0.057	43.824	0.643	0.828	0.000	0.000	2.050
K	0.004	0.000	0.000	0.000	0.000	0.103	43.084	7.039	0.701	0.000	0.000	0.004

A breakdown of the NYCA monthly EUE values by hour is provided below. The table below demonstrates the large spread of risk hours during the peak summer and winter months.

Table B.6 Monthly EUE Values by Hour

NYCA EUE per month and hour (MWh/hr)

HB	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23
JAN	0.000	0.000	0.000	0.000	0.000	0.000	0.213	1.494	0.537	0.131	0.063	0.045	0.041	0.030	0.001	0.222	1.520	7.299	0.823	0.372	1.246	0.075	0.000	0.000
FEB	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.003	0.017	0.017	0.030	0.002	0.004	0.001	0.000	0.000	0.000	0.073	0.064	0.005	0.055	0.000	0.000	0.000
MAR	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
APR	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
MAY	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
JUN	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.002	0.002	0.043	0.029	0.026	0.017	0.021	0.010	0.005	0.003	0.000	0.000	0.000
JUL	0.002	0.000	0.000	0.000	0.000	0.000	0.000	0.048	0.804	1.882	3.129	5.264	12.259	11.901	6.081	19.723	23.737	22.911	14.029	5.764	9.075	3.471	0.257	0.003
AUG	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.158	0.257	0.709	0.776	1.261	1.617	1.238	1.020	0.555	0.113	0.006	0.000	0.000
SEP	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.011	0.000	0.118	0.197	0.230	0.537	0.394	0.042	0.000	0.000	0.000	0.000	0.000
OCT	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
NOV	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
DEC	0.000	0.000	0.000	0.000	0.000	0.020	0.547	0.884	0.057	0.014	0.019	0.005	0.005	0.011	0.000	0.139	1.153	1.690	0.119	0.042	0.667	0.011	0.001	0.000

B.3.2 EUE Heatmaps for the NYCA

The Figures B.5 and B.6 depict the annual EUE across the NYCA zones measured in megawatt-hours per year (MWh/yr) for the 2026-2027 IRM Study FBC (see Figure B.5) and from the 2025-2026 IRM Study (see Figure B.6). The figures illustrate the spatial variation in reliability risk through the use of heatmaps which are a data visualization tool that uses color to represent values in a two-dimensional grid, making complex data easier to understand at a glance. The white areas indicate lower EUE values and red areas representing higher EUE values. Most zones exhibit relatively low EUE values, while the highest values occur in New York City (i.e., Load Zone J) and Long Island (i.e., Load Zone K). The comparison of both study years shows that the downstate zones have higher EUE values. Although the maximum annual EUE value occurred in Load Zone J for both study years, the value for the 2026-2027 IRM Study FBC is lower than the 2025-2026 IRM Study FBC. The 2026-2027 IRM Study FBC also demonstrates a higher annual value in Load Zone K compared to last year's study.

Figure B.5 NYCA Distribution of EUE 2026-2027 IRM Study

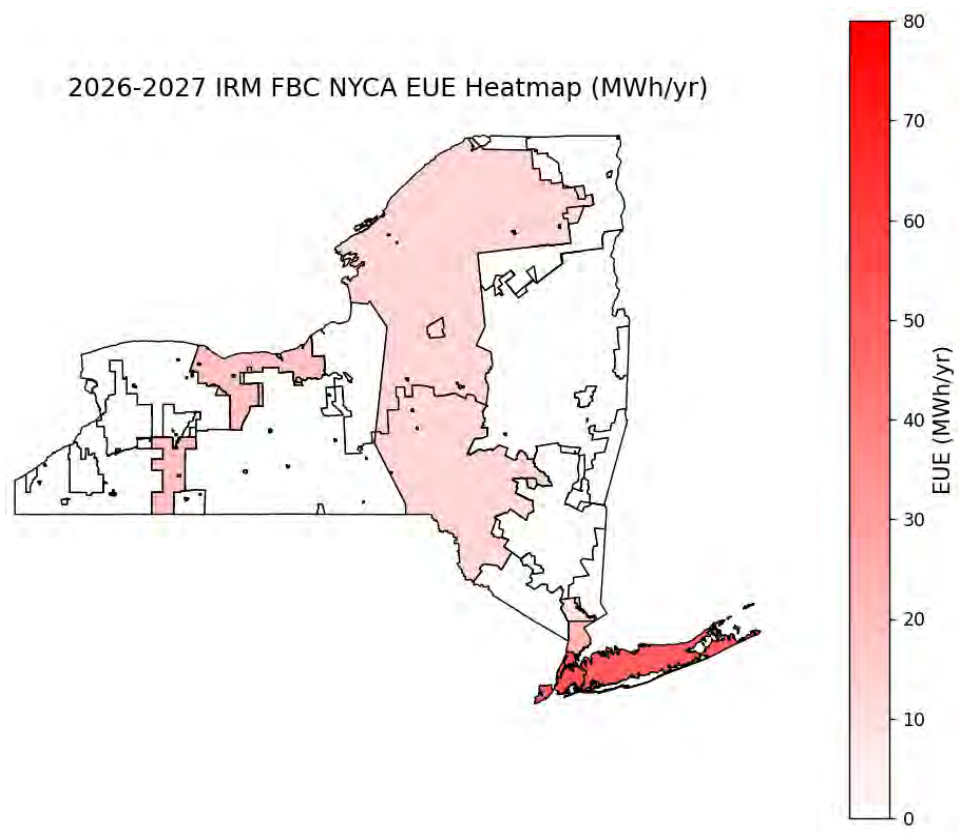
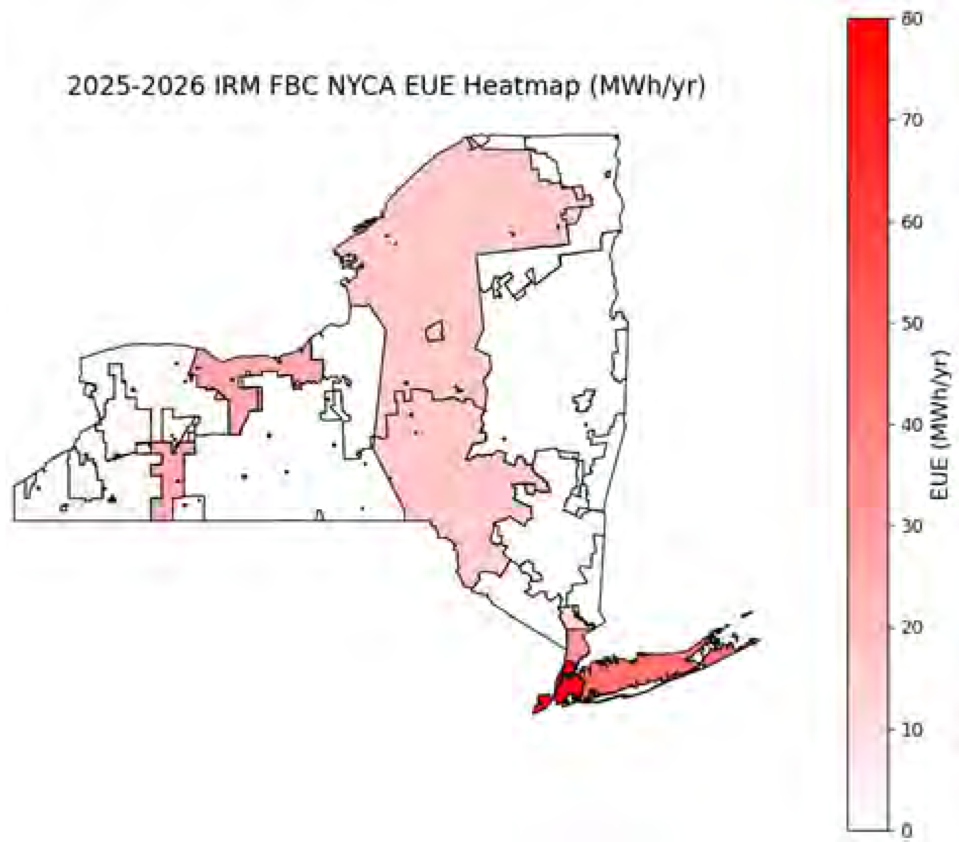


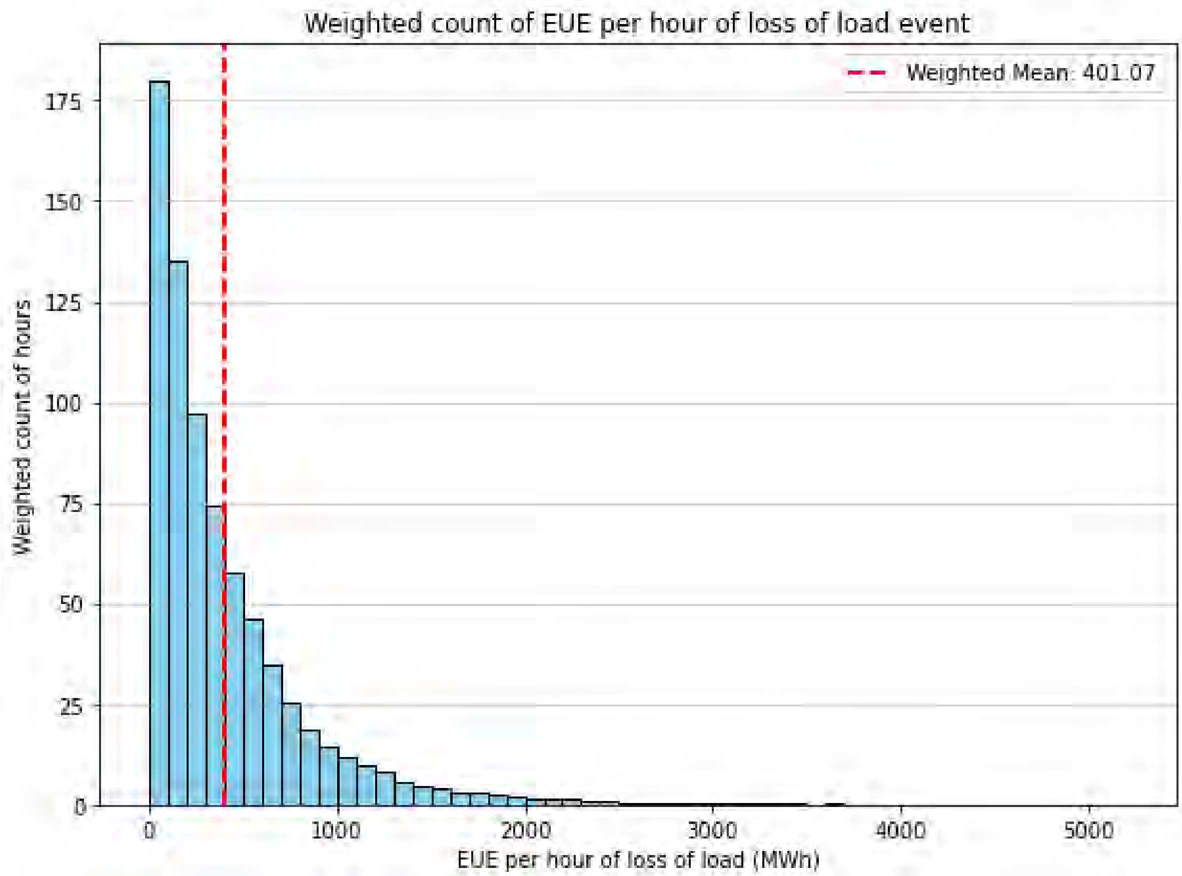
Figure B.6 NYCA EUE Distribution 2025-2026 IRM Study



B.3.3 EUE Hourly Distribution

The Figure B.7 provides the weighted distribution of EUE per hour during loss of load events, measured in MWh, for the 2026-2027 IRM Study FBC. Each histogram bar represents a 100 MWh interval, and the count of hours is weighted by the load level bin in which the event occurs. The distribution is strongly right-skewed, with the majority of events concentrated at lower EUE levels and a long tail representing infrequent but severe high-EUE occurrences. The red dashed line indicates the weighted mean of approximately 401 MWh, representing the average EUE during one hour of a loss of load event.

Figure B.7 NYCA EUE Distribution 2025-2026 IRM Study



Appendix C

Impact of Environmental Regulations

C. Impact of Environmental Regulations- Appendix C

Federal, state, and local government regulatory programs may impact the operation and reliability of New York's bulk power system. Of note, New York enacted the Climate Leadership and Community Protection Act (CLCPA) and promulgated various regulations collectively intended to limit greenhouse gas (GHG) emissions and support the development of new renewable energy, energy storage, and energy efficiency resources. Compliance with state and federal regulatory initiatives and permitting requirements may require investment by the owners of New York's existing thermal power plants to continue in operation. If the owners of those plants must make significant investments to comply, the cost of these investments could lead to retirements, and therefore new resources may be needed to maintain the reliability of the bulk power system. Other regulatory initiatives being undertaken by the State of New York may preclude certain units from continuing in operation in their current configuration. Many of the fossil fuel-fired generators impacted by these emissions regulations have been in operation for more than 50 years, are located in downstate New York, and may be critical to reliable electric system operations until sufficient replacement resources become available. The NYISO executes reliability planning processes to evaluate the implications of resource deactivations or changes in commercial operation in both the short- and long-term. This section reviews the status of various regulatory programs, which may impact power system operations and reliability.

C.1 Combustion Turbine NOX Emission Limits

The New York State Department of Environmental Conservation (DEC) Part 227-3 significantly lowers NO_X emission limits for simple cycle gas turbines (the "Peaker Rule"). The rule is applicable during the ozone season (May 1- September 30) and establishes lower emission limits in two phases, effective May 1, 2023, and May 1, 2025. The rule required compliance actions for units with approximately 3,300 MW of capacity (nameplate) located predominantly in southeastern New York and required the owners of affected facilities to file compliance plans by March 2020. The NYISO used compliance plans submitted by generators under Part 227-3 to develop the assumed outage pattern of the impacted units in its Reliability Planning Process.

The 2023 Quarter 2 Short Term Assessment of Reliability (2023 Q2 STAR), which was completed on July 14, 2023, 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.[7] As of May 1, 2023, 1,027 MW of affected generation deactivated or limited their operation. An additional 590 MW of affected generation were expected to become unavailable beginning May 1, 2025, all of which are located in New York City. With this additional generation unavailable, the 2023 Q2 STAR found Load Zone J deficient by 446 MW for a duration of nine hours.

[7] 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)

On November 20, 2023, the NYISO determined that no proposals could be installed by May 2025, or were sufficient to address the identified deficiency. As a result, consistent with provisions of the Peaker Rule that permit the NYISO to temporarily retain affected generation if no other solutions are viable or sufficient to address an identified reliability need, the NYISO identified generators on the Gowanus 2 & 3 and Narrows 1 & 2 barges (672 MW nameplate) as the temporary solution for the reliability need in New York City. In accordance with the DEC Peaker Rule's reliability provision, the Gowanus and Narrows generators may remain available to operate for up to an additional two years (until May 1, 2029) if the NYISO or Con Edison determine that the reliability need still exists and a permanent solution has been identified and is in the process of construction. The DEC Peaker Rule, however, does not provide for peaker generators to continue operating after this date without meeting the emissions requirements. As of May 1, 2025, an additional 270 MW of affected generation deactivated. The 2025 Quarter 3 Short Term Assessment of Reliability (2025 Q3 STAR) identified generator deactivation and near-term reliability needs in New York City, in part due to the proposed retirement of Gowanus and Narrows. These deficiencies occur during the summer from 2026 through 2030. The reliability needs range from 410–650 MW for six to eight hours in 2026, increasing to 500–1,130 MW for eight to thirteen hours by 2030. On November 10, 2025, the NYISO issued a solution solicitation to address the needs identified in the 2025 Q3 STAR. Following the 60-day solicitation, the NYISO will evaluate the proposed solutions and issue a Short-term Reliability Process Report which shall indicate the NYISO's selection of a solution or combination of solutions, along with a reasoned explanation regarding why particular generation and/or transmission solutions were selected. If needed, interim solutions must also be in-place to keep the grid reliable. This solution selection process is designed to ensure that executing a Reliability Must Run (RMR) Agreement with generators is a last resort to addressing a reliability need.

C.2 U.S. Clean Water Act: Best Technology Available for Plant Cooling Water Intake

The U.S. Environmental Protection Agency (EPA) has issued a new Clean Water Act Section 316b rule providing standards for the design and operation of power plant cooling systems that withdraw more than 2 million gallons per day (mgd) of water from waters of the United States and use at least 25 percent of the water they withdraw exclusively for cooling purposes. This rule is being implemented by the DEC, which has finalized Commissioner Policy 52 for the implementation of the Best Technology Available (BTA) for plant cooling water intake structures. This policy is activated upon renewal of a plant's water withdrawal and discharge permit. Based upon a review of current information available from the DEC, the NYISO has estimated that 13,500 MW of nameplate capacity is affected by this rule, some of which could be required to undertake major system retrofits, including closed-cycle cooling systems. Several generators' permits include a 15% capacity factor limitation over their 5-year water permit term to limit the facilities' environmental impact. Conditions which limit capacity factors could potentially limit generator availability.

Plant	Status as of September 2025
Arthur Kill	BTA in place, verification under review
Astoria	BTA in place, verification under review
Barrett	Permit drafting underway with equipment enhancements, SAPA extended
Bowline	BTA in place, 15% Capacity Factor, BTA Decision made, monitoring
Brooklyn Navy Yard	Permit drafting underway
Danskammer	BTA in place, undergoing permit renewal review
East River	BTA in place
Fitzpatrick	BTA studies being evaluated
Ginna	BTA studies being evaluated
Greenidge	BTA in place, thermal studies underway
Nine Mile Pt 1	BTA studies being evaluated
Northport	BTA in place, verification under review
Oswego	BTA conditions under review
Port Jefferson	BTA in place, 15% Capacity Factor, verification
Ravenswood	BTA in place, additional studies under review
Roseton	BTA in place
Wheelabrator Hudson Falls	Technical review
Wheelabrator Westchester	BTA in place

C.3 New York City Residual Oil Elimination

New York City passed legislation in December 2017 that prohibits the combustion of fuel oil numbers 6 and 4 in electric generators within New York City by 2020 and 2025, respectively. The rule contains an additional compliance pathway providing for conversion directly to fuel oil number 2 by 2023. The rule affected about 3,000 MW of generation in New York City. The affected generators installed new fuel storage and handling equipment and converted their facilities to comply with the law.

C.4 Regional Greenhouse Gas Initiative (RGGI)

RGGI is a multi-state power-sector carbon dioxide (CO_2) emissions cap-and-trade initiative that requires affected generators of 25 MW (nameplate) or larger to procure emissions allowances authorizing them to emit carbon dioxide. The DEC extended RGGI applicability in New York to certain generators of 15 MW (nameplate) or larger in 2021.

In their second program review, the RGGI states agreed to a 30% cap reduction between 2020 and 2030, essentially ratcheting down the availability of allowances to generators that emit CO_2. These emission allowance caps are not likely to trigger reliability concerns as the accompanying program design provides for mechanisms that consider reliability on various timescales, including multi-year compliance periods, allowance banking provisions, the Cost Containment Reserve, and periodic program reviews.

The RGGI states completed their third program review in July 2025. The states agreed to cap trajectories with increased stringency beginning in 2027 at 69.8 million tons and decreasing through 2037 to 9 million tons across the 10-state region. The states agreed to expand and extend the Cost

Containment Reserve, eliminate the Emissions Containment Reserve and replace it with a higher auction reserve price, and to not perform an adjustment to address the bank of allowances. These features are seen as additive to the allowance supply which may be needed given the stringent agreed upon cap levels. The program design changes resulting from the third program review are expected to increase allowance prices going forward. Taken together, these proposals have the potential to constrain generator operations if sufficient allowances are not available to the regulated resources, which in certain instances could lead to reliability concerns. Reductions in operational and financial flexibility may need to be recognized by implementing complementary program design elements that can address these concerns. The RGGI states have committed to beginning the next program review in 2028.

C.5 Distributed Generator NOX Emission Limits

The DEC has adopted Part 222, a rule to limit the NO_X emissions from small behind the meter generators that operate as an economic dispatch source in the New York City Metropolitan Area which are located at facilities with potential NO_X emissions less than 25 tons of NO_X per year and driven by reciprocating or rotary internal combustion engines. The emission limits become effective in two phases, May 1, 2021 and May 1, 2025. Affected facilities were required to either obtain a registration or permit by March 15, 2021 and notify the DEC whether the generator will operate as an economic dispatch source subject to the provisions of Part 222. NYSERDA estimates that approximately 500 MW of generation is affected.[8]

C.6 Cross-State Air Pollution Rule (CSAPR)

The US EPA CSAPR limits emission of SO_2 and NO_X from fossil fuel fired electricity generating units (EGUs) greater than 25 MW in 27 states by establishing emissions caps and restricting allowance trading within various programs. The CSAPR ozone season encompasses May 1-September 30 each year.

The final Revised CSAPR Update became effective June 29, 2021. This rule reduced ozone season NO_X limits in 12 of 22 states within the existing Group 2 ozone season trading program by creating a new Group 3. The total 12 state budget decreased by 37% between 2020 and 2021 to 107,085 tons, compared to 2021 emissions of 90,413 tons. Over the same period, the NY budget went down 33% from 5,135 to 3,416 tons, while NY ozone season emissions were 3,564 tons in 2020, 3,994 tons in 2021, 3,502 tons in 2022, 3,335 tons in 2023 and 3,476 tons in 2024. If NY generators emit significantly above their allowable levels the state may collectively exceed its trading limit, in which case higher emitting resources will need to surrender allowances at a rate of 3:1 for their excess emissions.

The EPA issued the final Good Neighbor Plan (GNP) for the 2015 Ozone NAAQS on March 15, 2023 expanding the Group 3 region from 12 to 22 states. Under the GNP, NY's ozone season NO_X budget

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[8] https://energyplan.ny.gov/-/media/Project/EnergyPlan/files/Draft-2025-Energy-Plan/Transmission-Distribution-Reliability-Report.pdf

in 2023-2025 *increased* to 3,912 tons. Following legal challenges, on June 27, 2024, the Supreme Court of the United States issued a stay of the GNP. In response, on October 29, 2024, the EPA addressed the court's remand by reverting all GNP states back to their prior CSAPR compliance obligations beginning with the 2024 ozone season. Reverting the GNP states to their prior ozone season programs generally resulted in an increased program-wide NO_X emissions cap. However, for New York reverting to the prior CSAPR will reduce the state's ozone season cap in 2024, which will remain at that level in subsequent years. New York is now a member of the Group 2 Expanded ozone season NO_X trading program.

C.7 Federal Greenhouse Gas Standards

The EPA issued final standards for CO_2 emissions from new combustion turbine and existing steam turbine electric generators which became effective on July 8, 2024. States would submit plans categorizing each existing affected steam turbine generator within 2 years. New natural gas- and oil-fired combustion turbine generators would need to achieve CO_2 removal rates of 90% beginning in 2032; as would existing coal-fired steam generators that do not commit to cease operations before 2039. New Yorks' existing oil- and gas-fired steam turbine generators that frequently operate would be required to maintain historically achieved emissions rate levels. On June 11, 2025, EPA proposed to repeal all GHG emissions standards for power plants under Section 111 of the Clean Air Act.[9] On July 29, 2025, the EPA proposed repeal of the 2009 Endangerment Finding which allowed for regulations of GHG under the Clean Air Act.[10]

C.8 New York Power Authority Small Gas Turbine Phase Out

Provisions included in New York State's *2023-24 Enacted State Budget* broadened NYPA's authority to develop renewable energy and required it to phase-out their small natural gas power plants.[11] NYPA was required to publish a plan by May 2025 to phase out the production of electricity from its seven smaller natural gas plants (simple-cycle combustion turbines) in New York City and Long Island totaling 517 MW (nameplate) by December 31, 2030, unless those plants are determined to be necessary for electric system reliability, emergency power service, or energy from other sources that may replace energy from NYPA's affected plants would result in more than a de minimis net increase in emissions within a disadvantaged community. NYPA's plan is required to include recommendations and a proposed strategy to replace some or all of the affected plants with renewable energy systems, if appropriate. The basis for such determinations in NYPA's plan, which are required to be updated at least every two years, must be made publicly available along with the supporting documentation for the determination.

NYPA published the Small Natural Gas Power Plant Transition Plan on May 9, 2025, laying out a six-step process which would allow for the retirement of these assets should certain conditions be met

[9] https://www.epa.gov/stationary-sources-air-pollution/greenhouse-gas-standards-and-guidelines-fossil-fuel-fired-power
[10] https://www.epa.gov/regulations-emissions-vehicles-and-engines/proposed-rule-reconsideration-2009-endangerment-finding
[11] See 2023 Laws of New York, Ch. 56, Part QQ, § 5.

at each successive step.[12] NYPA acknowledged that renewable replacement was not feasible at these sites and was actively examining battery storage resources at a number of the sites. Included in NYPA's Transition Plan process, additional studies must be conducted by the NYISO and other consultants to inform the evaluation on impacts of the retirement of these resources.

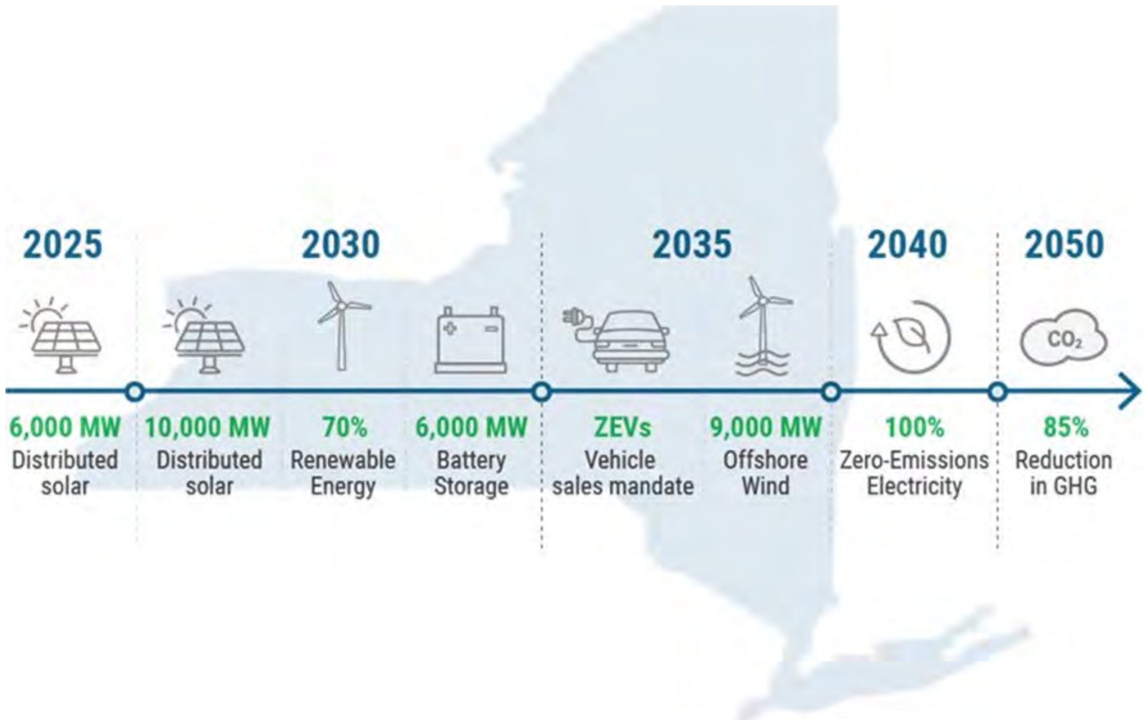
C.9 Climate Leadership and Community Protection Act (CLCPA)

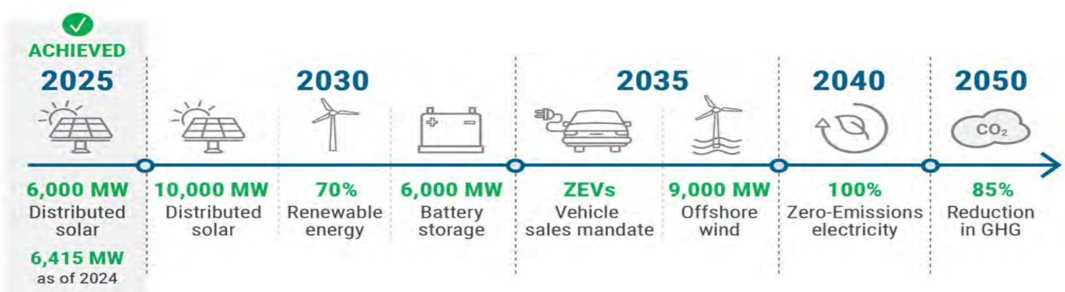
The CLCPA requires, among other things, that 70% of electric energy be generated from renewable resources by 2030 and 100% of electric energy be provided by zero emission resources by 2040. The statute will require the displacement of New York's fossil fuel-fired generating fleet with renewable resources and other eligible clean energy resources. During this transition, the NPCC and NYSRC resource adequacy rules will require the New York Control Area to maintain reliability criteria for the New York bulk electric system. In addition, the economy-wide GHG emission reduction requirements necessitate significant electrification of the building and transportation sectors.

The CLCPA builds upon programs and targets already established under the Clean Energy Standard (CES) and by other state policies. The combined set of requirements for new resources are described in more detail in the sections below. The second CLCPA informational report indicates, while the distributed solar deployments have progressed on track, achievement of the remaining CLCPA policies have been delayed relative to their targets.[13] The figure next page describes the timing and requirements of the major combined clean energy and efficiency policies in New York State.

[12] https://edge.sitecorecloud.io/newyorkpowe85b6-nypad19c-prod795c-a32e/media/Feature/nypa-sites/small-natural-gas-media/SNGPP-Transition-Plan.pdf

[13] https://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={D0147799-0000-CE6F-B0E3-C2569C01A378}





Source: NYISO

C.10 Offshore Wind Development

The CLCPA requires 9,000 MW of offshore wind (OSW) capacity to be developed by 2035. The New York State Public Service Commission (PSC) has issued several orders directing NYSERDA to procure OSW Renewable Energy Certificates (ORECs) from developers for up to the 9,000 MW offshore wind target. As of October 2025, NYSERDA has executed contracts with Empire 1 (810 MW) and Sunrise (924 MW) offshore wind projects. NYSERDA released the 2024 OSW solicitation in July 2024, with resulting contract awards announcement still pending. In July 2025, the PSC cancelled the ongoing New York City Offshore Wind Public Policy Transmission Need (PPTN) citing a lack of projects and current lack of federal policy support for offshore wind. Previously, Long Island Power Authority contracted with South Fork Offshore Wind, a 132 MW project which entered service in July 2024.

C.11 Comprehensive Energy Efficiency Initiative

The PSC has supported energy efficiency programs directing utility actions by developing budgets and targets to accelerate energy efficiency savings in New York State. Since passage of the CLCPA, additional building electrification initiatives direct utility programs to support heat pump adoption, in addition to increased deployment of more conventional utility energy efficiency programs.

C.12 Storage Deployment Target

The CLCPA required 3,000 MW of energy storage capacity to be developed by 2030. On June 20, 2024, the PSC adopted and updated the statewide deployment goal to 6,000 MW of energy storage resources by 2030. Under the updated storage roadmap, NYSERDA and the New York State Department of Public Service (DPS) expect roughly half of this goal to be met by behind-the-meter resources while the other half is expected to be grid-connected. DPS reported that 509 MW in energy storage capacity was deployed and an additional 893 MW were awarded/contracted as of March 31, 2025. NYSERDA issued the first of three solicitations for Index Storage Credit contracts to ultimately support 3,000 MW of energy storage resources for 15 years. Since 2019, over 2,000 MW of energy storage resources have completed the NYISO interconnection process (*i.e.*, accepted the required facility studies and/or signed interconnection agreements).

C.13 Distributed Solar Program

The CLCPA requires 6,000 MW of installed distributed solar capacity by 2025. On April 14, 2022, the PSC extended NYSERDA's NY-Sun Program, raising the total distributed solar capacity goal to at least 10,000 MW by 2030. Attainment of these targets has been bolstered by strong growth in BTM solar capacity over recent years, along with a robust pipeline of potential future projects. On October 17, 2024, the state announced early achievement of the 2025 installed capacity goal, surpassing 6,000 MW of installed distributed solar capacity.

C.14 Clean Energy Standard (CES)

The PSC initiated the Renewable Portfolio Standards in 2004 to help support the development of renewable energy resources for New York. In 2016 the PSC combined the Renewable Energy

Standard (RES) and a Zero Emission Credit (ZEC) Requirements under a new CES policy. Through the CES, NYSERDA supports the development of new renewable energy resources, and the continued operation of the upstate nuclear generators through March 2029, by signing Renewable Energy Certificate (REC) and ZEC contracts with generators for the environmental attributes associated with their generation.

The PSC issued an Order Modifying the CES on October 15, 2020, to align the existing Clean Energy Standard with the requirements of the CLCPA. Specifically, the order increased the RES from 50% to 70% in 2030 and modified the definition of eligible renewable energy resources to align with the CLCPA. The Order authorized the procurement schedules for Tier 1 and Offshore Wind resources needed to achieve the 2030 mandates. The Order also included a new Tier 4 specifically to recognize incremental renewable energy delivered into Zone J. Tier 4 REC contracts with Champlain Hudson Power Express (CHPE) was approved on April 14, 2022. CHPE will add 1,250 MW of controllable HVDC connections into New York City.

On July 1, 2024, the Draft Clean Energy Standard Biennial Review found a growing shortfall in expected attainment of the 2030 renewable energy target, primarily due to increased load forecasts and delays in renewable projects achieving commercial operation. NYSERDA and DPS Staff recommended delaying the RES 70% renewable energy target date to 2033 and expanding annual Tier 1 REC procurements. On May 15, 2025, the PSC approved an order adopting the CES Biennial Review report as final, expanded the Tier 1 REC solicitation schedule from 2026 through 2029, and retained the 70% by 2030 target but committed to reexamine the target again in the 2026 Biennial Review. The PSC is considering an extension of the ZEC program through 2049 to support the relicensing of the existing upstate nuclear generators.

C.15 Economy-wide Greenhouse Gas Emissions Limits and New York Cap-and-Invest

The CLCPA includes an approach to accounting for climate impacts of emissions of various GHGs which provide greater weight to the impact of methane emissions relative to the emissions of carbon dioxide and accounts for upstream emissions that occur out-of-state. The 1990 inventory, methodology, and limits were finalized by DEC as Part 496 in 2020.

The DEC is required under the CLCPA to complete additional regulations to enforce the economy wide GHG limits. Principle among these regulatory initiatives, the DEC and NYSERDA are developing regulations to implement an economy-wide cap-and-invest program. The cap-and-invest initiative would be implemented through a suite of three regulations: a Reporting Rule, a Cap-and-Invest Rule, and an Auction Rule. The DEC proposed Part 253 Mandatory Greenhouse Gas Reporting Rule on March 26, 2025, and is reviewing comments received. The proposal would require reporting entities to begin reporting June 1, 2027, for emissions that occurred in 2026. Electric generators and utilities, while proposed to be reporting entities under the reporting rule, may or may not ultimately be obligated sectors under potentially forthcoming cap-and-invest regulations.

C.16 CLCPA Impact on Air Emission Permits

In addition, fossil fuel-fired generation projects face further scrutiny under the CLCPA, which requires state agencies to consider consistency with the statewide GHG emission limits and disproportionate impacts on Disadvantaged Communities (DACs) when issuing permits.

On October 27, 2021, the DEC denied air emission permit modification applications by two existing generators to repower their facilities with new natural gas generators. The Danskammer Energy Center sought authorization to construct a new natural gas fired combined cycle power generation facility of 536 MW to replace its existing 532 MW steam turbine generating facility. Astoria Gas Turbine Power, LLC, a subsidiary of NRG Energy, sought to construct the Astoria Replacement Project, which would consist of a new simple cycle dual fuel (natural gas and distillate oil) peaking combustion turbine generator of 437 MW. On June 30, 2022, the DEC also denied the renewal application for Greenidge Generation's air permits citing CLCPA compliance demonstration. The DEC determined that each of the projects would be inconsistent or interfere with the attainment of statewide GHG emission limits established by the CLCPA. The DEC found that the applicants had not provided adequate justification, such as resolution of an electric system reliability need, to overcome the DEC's determination that the air emissions would be inconsistent or interfere with attainment of the CLCPA greenhouse gas emission requirements. The DEC noted at that time, the reliability needs the NYISO identified in its 2020 RNA had been resolved by post RNA updates, and that the announced Tier 4 projects would significantly increase transmission capacity into New York City.

In December 2022, the DEC finalized department program policy DAR-21 to implement the GHG permitting requirements in the CLCPA within state and federal air permits. Facilities are required to submit a GHG Mitigation Plan with their Title V applications addressing climate impacts associated with the facility. On May 8, 2024, the DEC released DEP 24-1 to implement the environmental justice and disproportionate burden aspects of the CLCPA within many environmental permits. For facilities "in or likely to affect" a DAC, a Disproportionate Burden Report and meaningful community engagement is required under the department policy.

C.17 Accelerated Renewable Energy Growth and Community Benefit Act

The Accelerated Renewable Energy Growth and Community Benefit Act was signed into law on April 3, 2020, to assist in the achievement of the clean energy and environmental targets outlined in the CLCPA. This Act requires the PSC to establish new planning processes to enable the transmission and distribution expansion to support the CLCPA targets. On May 14, 2020, the PSC commenced a proceeding to implement the Act with respect to utility-based plans for upgrades to local transmission and distribution needed to support the mandates of the CLCPA. Utilities submitted preliminary upgrade proposals by August 1, 2020. The Joint Utilities filed an Initial Power Grid Study report at the PSC on November 2, 2020. The report addresses local transmission system needs, existing system planning process and identified some potential modifications to those processes, accounting for CLCPA benefits in planning and investment criteria, and cost containment, cost allocation and cost recovery mechanisms for transmission projects. The PSC subsequently issued orders approving Phase 1 and Phase 2 projects as well as other recommendations stemming from the Power Grid Study, to meet CLCPA requirements. In December 2022, the Joint Utilities filed the Coordinated Grid Planning Process (CGPP) proposal for Commission review. In August 2023, the Commission approved the CGPP with several modifications from what was proposed by the Joint Utilities. The CGPP was designed by the Joint Utilities to assess the transmission needs of the system over a 20-year horizon. The study process is a three-year cycle and includes six stages moving from data collection and modeling and through various stages of capacity expansion and transmission security analysis. The process culminates in a report and recommendations for the Commission's consideration in the identification of transmission projects. The utilities continue working along with the NYISO within the CGPP to identify local transmission and distribution upgrades, coordinate on grid expansion planning and cost sharing. The first cycle of the CGPP began in October 2023 and is expected to conclude in 2026.

The Act also created an Office of Renewable Energy Siting (ORES) within the New York State Department of State to speed the permitting timeline of large-scale renewable energy facilities. Subsequently, the ORES has moved to the DPS and incorporated transmission siting within the same office to help speed the project permitting process. Since 2021, ORES has approved 27 renewable energy projects representing over 3,800 MW.

The Act also directs the PSC and NYSERDA to advance "Build Ready" projects that package project ownership and renewable energy certificate contracts into a single competitive procurement. On October 15, 2020, the PSC issued an order to authorize NYSERDA to begin procurement of Build Ready sites and projects as early as 2022. The program advanced the 12 MW Benson Mines solar facility at a through its first solicitation, auctioning the projects and Tier 1 REC contract to a private developer. NYSERDA issued the Build Ready five-year program review on October 1, 2025, recommending termination of the PSC-funded Build-Ready Program which would continue by providing support for the siting and integration of new economic development and load projects.

C.18 Study Impacts and Insights

To inform policymakers, market participants, and the public, the NYISO continuously studies the impact of these various policies on the future supply mix. The NYISO's *2023-2042 System and Resource Outlook* policy scenarios[14] showed the long-term need for dispatchable emissions-free resources (DEFRs) to operate during extended periods of reduced renewable resource output and to meet winter peak demand needs in an electrified future. These scenarios highlighted the need for resources with these characteristics in addition to energy storage and load flexibility to address fundamental issues of load and renewable generation misalignment across seasons. The studies

[14] *See* System and Resource Outlook, A Report from the New York Independent System Operator, available at https://www.nyiso.com/documents/20142/45816558/Outlook-Data-Catalog-2023.pdf/8db92692-9ddb-f91b-fa52-e46d0a613202

also imply increasing ramping demands placed on resources primarily to respond to the increased intermittent output of renewable generation and increased variability of electrified loads.

As outlined in the NYISO's draft 2025–2034 Comprehensive Reliability Plan, New York's electric grid is at an inflection point, driven by the convergence of three structural trends: the aging of the existing generation fleet, the rapid growth of large loads, and the increasing difficulty of developing new dispatchable resources. Presently, 25% of the state's total generating capacity is fossil-fuel-based generation that has been in operation for more than 50 years. At the same time, new demand from data centers, industrial facilities, and electrification is accelerating, placing additional stress on the grid. The system needs resources that can perform reliably during periods of high net load, low intermittent output, and extreme weather. These resources must be dispatchable, flexible, and capable of operating during extended periods of extreme weather and high demand. While renewable generation and battery storage are essential components of the future grid, they are not sufficient on their own to meet all reliability needs.

Resource adequacy is the cornerstone of electric system reliability, ensuring sufficient capacity is available to meet demand under a wide range of conditions, including peak load, weather variability, and unexpected outages. The issue is not simply one of quantity of capacity, but also of quality, timing, and location of those resources' ability to serve load. As highlighted in recent NYISO planning studies and the NYISO's comments on the draft State Energy Plan[15], the system also requires clean firm capacity resources that can operate independently of weather conditions and provide sustained output when needed to achieve the CLCPA targets. While a diverse mix of resources can collectively provide the reliability attributes needed to maintain system adequacy, persistent development challenges are raising serious concerns about whether the necessary supply will materialize in time to meet growing demand and offset aging generation concerns.

[15] https://www.nyiso.com/documents/20142/1402310/20251006_NYISOCmmnts_DraftStateEnergyPlan.pdf/5675df00-b281-bc67-f4b3-26e2155f6826

Appendix D

ICAP to UCAP Translations

D. ICAP to UCAP Translation – Appendix D

The NYISO administers the capacity requirements to all loads in the NYCA. In 2002, the NYISO adopted the Unforced Capacity (UCAP) methodology for determining system requirements, unit ratings and market settlements. The UCAP methodology uses individual generating unit data for output and availability to determine an expected level of resources that can be considered for system planning, operation and marketing purposes. EFORd is developed from this process for each generating unit and applied to the unit's DMNC test value to determine the resulting level of UCAP.

Individual unit EFORd factors are taken in aggregate on both a Statewide and Locational basis and used to effectively "translate" the IRM and LCRs previously determined in the GE-MARS Analysis in terms of ICAP, into an equivalent UCAP basis.

Table D.1 summarizes the NYCA historical capacity parameters for the last 26 years including Base Case IRMs, approved IRMs, UCAP requirements, and NYISO approved LCRs (for New York City, Long Island and the G-J Locality).

Table D.1 Historical NYCA Capacity Parameters

Capability Year (May - April)	Base Case IRM (%)	EC Approved IRM (%)	NYCA Equivalent UCAP Requirement (%)	NYISO Approved J LCR (%)	NYISO Approved K LCR (%)	NYISO Approved G-J LCR (%)
2000-2001	15.5	18.0		80.0	107.0	
2001-2002	17.1	18.0		80.0	98.0	
2002-2003	18.0	18.0		80.0	93.0	
2003-2004	17.5	18.0		80.0	95.0	
2004-2005	17.1	18.0	11.9	80.0	99.0	
2005-2006	17.6	18.0	12.0	80.0	99.0	
2006-2007	18.0	18.0	11.6	80.0	99.0	
2007-2008	16.0	16.5	11.3	80.0	99.0	
2008-2009	15.0	15.0	8.4	80.0	94.0	
2009-2010	16.2	16.5	7.2	80.0	97.5	
2010-2011	17.9	18.0	6.1	80.0	104.5	
2011-2012	15.5	15.5	6.0	81.0	101.5	
2012-2013	16.1	16.0	5.4	83.0	99.0	
2013-2014	17.1	17.0	6.6	86.0	105.0	
2014-2015	17.0	17.0	6.4	85.0	107.0	88.0
2015-2016	17.3	17.0	7.0	83.5	103.5	90.5
2016-2017	17.4	17.5	6.2	80.5	102.5	90.0
2017-2018	18.1	18.0	7.0	81.5	103.5	91.5
2018-2019	18.2	18.2	8.1	80.5	103.5	94.5
2019-2020	16.8	17.0	6.7	82.8	104.1	92.3
2020-2021	18.9	18.9	9.0	86.6	103.4	90.0
2021-2022	20.7	20.7	10.1	80.3	102.9	87.6
2022-2023	19.6	19.6	7.9	81.2	99.5	89.2
2023-2024	19.9	20.0	7.8	81.7	105.2	85.4
2024-2025	23.1	22.0	5.9	80.4	105.3	81.0
2025-2026	24.4	24.4	8.2	78.5	106.5	78.8

D.1 NYCA and NYC and LI Locational Translations

In the "Installed Capacity" section of the NYISO website, NYISO staff regularly post summer and winter Capability Period ICAP and UCAP calculations for the NYCA and the Localities. This information has been compiled and posted since 2006.

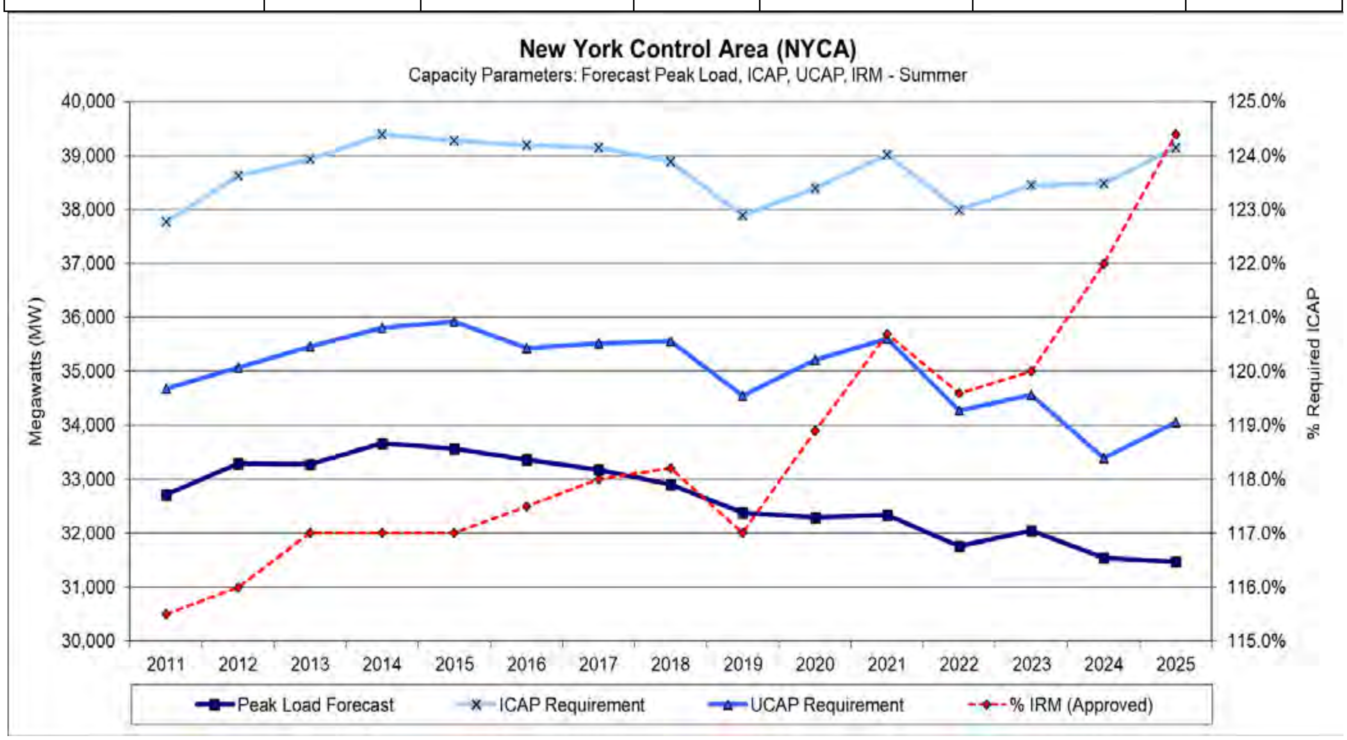
Locational ICAP/UCAP calculations are produced for New York City, Long Island, G-J Locality and the NYCA. Exhibits D.1.1 through D.1.4 summarizes the translation of ICAP requirements to UCAP requirements for these areas. The charts and tables included in these exhibits utilize data from the summer capability periods for the most recent 15 years beginning with the 2011 summer capability period.

This data reflects the interaction and relationships between the capacity parameters used this study, including forecast peak load, ICAP requirements, de-rating factors, UCAP requirements, IRMs, and LCRs. Since these parameters are so inextricably linked to each other, the graphical representation also helps one more easily visualize the annual changes in capacity requirements.

D.1.1 New York Control Area ICAP to UCAP Translation

Table D.2 New York Control Area ICAP to UCAP Translation

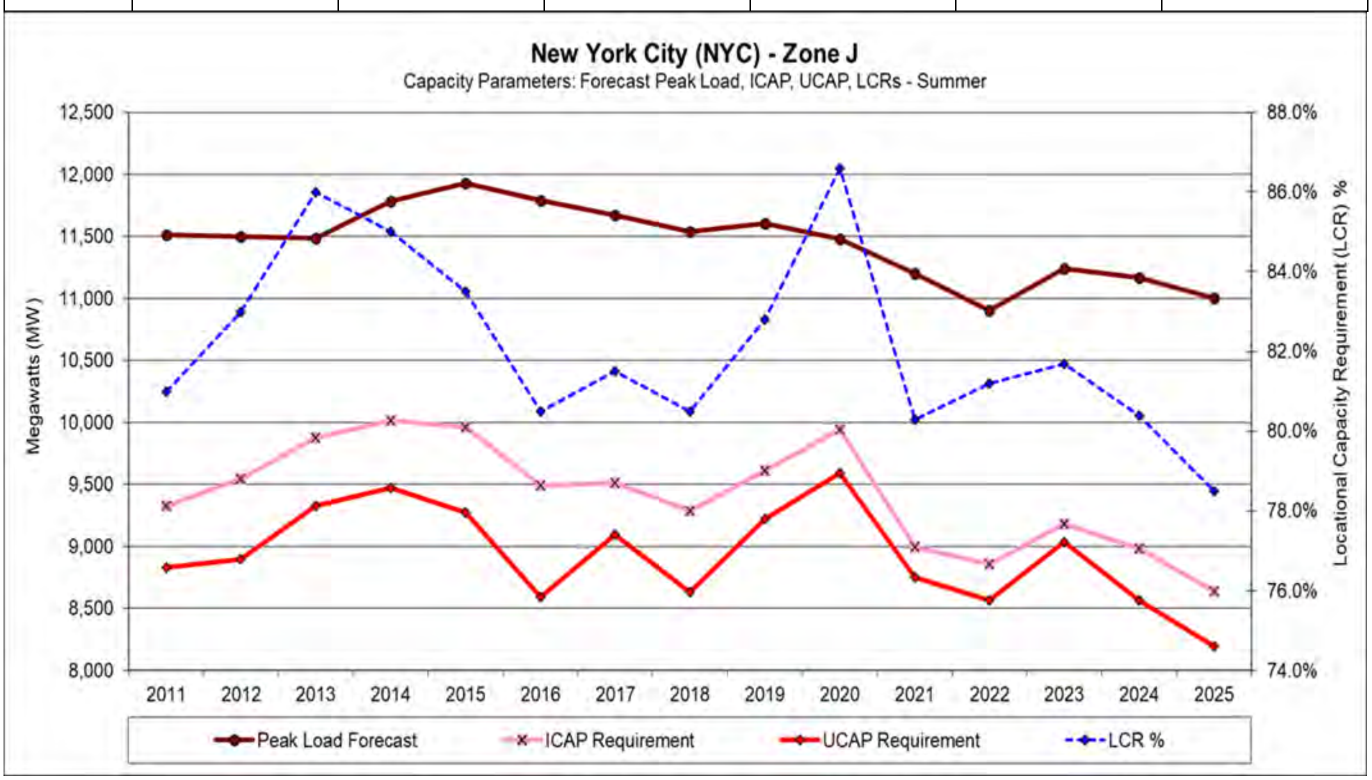
Table D.2 NYCA ICAP to UCAP Translation **Year**	**Forecast Peak Load (MW)**	**Installed Capacity Requirement (%)**	**Derate Factor**	**ICAP Requirement (MW)**	**UCAP Requirement (MW)**	**Effective UCAP (%)**
2011	32,712	115.5	0.0820	37,783	34,684	106.0
2012	33,295	116.0	0.0918	38,622	35,076	105.4
2013	33,279	117.0	0.0891	38,936	35,467	106.6
2014	33,666	117.0	0.0908	39,389	35,812	106.4
2015	33,567	117.0	0.0854	39,274	35,920	107.0
2016	33,359	117.5	0.0961	39,197	35,430	106.2
2017	33,178	118.0	0.0929	39,150	35,513	107.0
2018	32,903	118.2	0.0856	38,891	35,562	108.1
2019	32,383	117.0	0.0879	37,888	34,558	106.7
2020	32,296	118.9	0.0830	38,400	35,213	109.3
2021	32,333	120.7	0.0877	39,026	35,604	110.1
2022	31,767	119.6	0.0978	37,993	34,277	107.9
2023	32,049	120.0	0.1014	38,459	34,559	107.8
2024	31,542	122.0	0.1321	38,481	33,397	105.9
2025	31,469	124.4	0.1300	39,148	34,059	108.2



D.1.2 New York City ICAP to UCAP Translation

Table D.3 New York City ICAP to UCAP Translation

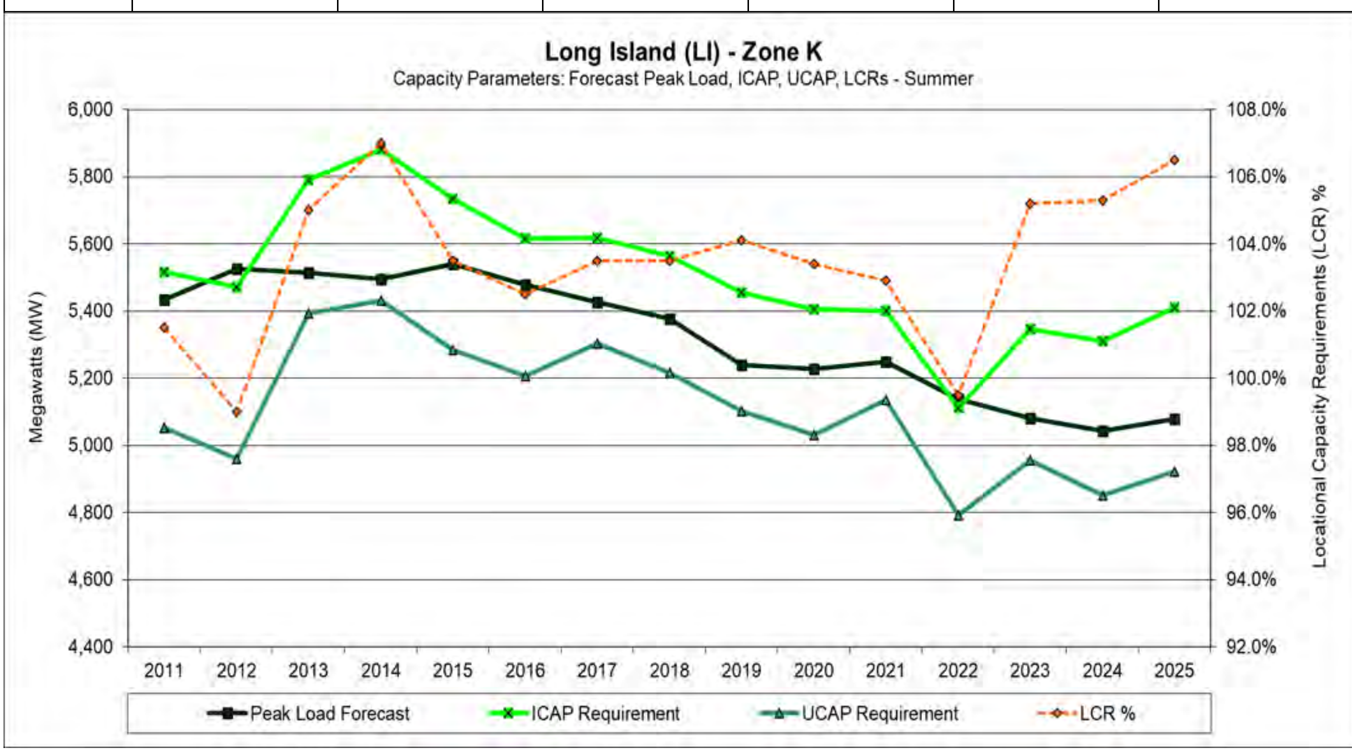
Year	Forecast Peak Load (MW)	Locational Capacity Requirement (%)	Derate Factor	ICAP Requirement (MW)	UCAP Requirement (MW)	Effective UCAP (%)
2011	11,514	81.0	0.0530	9,326	8,832	76.7
2012	11,500	83.0	0.0679	9,545	8,897	77.4
2013	11,485	86.0	0.0559	9,877	9,325	81.2
2014	11,783	85.0	0.0544	10,015	9,471	80.4
2015	11,929	83.5	0.0692	9,961	9,272	77.7
2016	11,794	80.5	0.0953	9,494	8,589	72.8
2017	11,670	81.5	0.0437	9,511	9,095	77.9
2018	11,539	80.5	0.0709	9,289	8,630	74.8
2019	11,607	82.8	0.0409	9,611	9,217	79.4
2020	11,477	86.6	0.0351	9,939	9,590	83.6
2021	11,199	80.3	0.0269	8,993	8,751	78.1
2022	10,906	81.2	0.0326	8,856	8,567	78.6
2023	11,239	81.7	0.0164	9,183	9,032	80.4
2024	11,168	80.4	0.0462	8,979	8,564	76.7
2025	11,005	78.5	0.0518	8,639	8,191	74.4



D.1.3 Long Island ICAP to UCAP Translation

Table D.4 Long Island ICAP to UCAP Translation

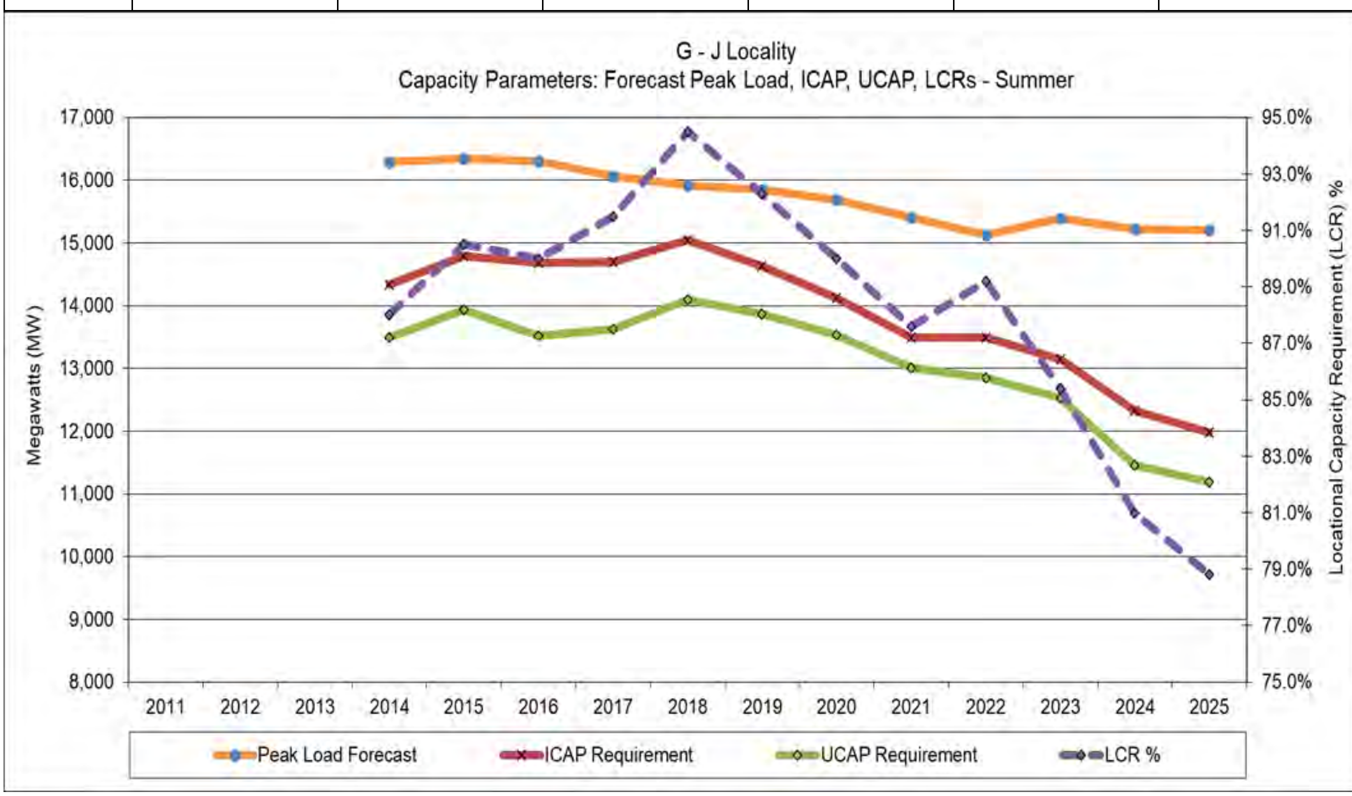
Year	Forecast Peak Load (MW)	Locational Capacity Requirement (%)	Derate Factor	ICAP Requirement (MW)	UCAP Requirement (MW)	Effective UCAP (%)
2011	5,434	101.5	0.0841	5,516	5,052	93.0
2012	5,526	99.0	0.0931	5,470	4,961	89.8
2013	5,515	105.0	0.0684	5,790	5,394	97.8
2014	5,496	107.0	0.0765	5,880	5,431	98.8
2015	5,539	103.5	0.0783	5,733	5,284	95.4
2016	5,479	102.5	0.0727	5,615	5,207	95.0
2017	5,427	103.5	0.0560	5,617	5,302	97.7
2018	5,376	103.5	0.0628	5,564	5,214	97.0
2019	5,240	104.1	0.0647	5,455	5,102	97.4
2020	5,228	103.4	0.0691	5,405	5,032	96.3
2021	5,249	102.9	0.0491	5,401	5,136	97.9
2022	5,138	99.5	0.0627	5,112	4,791	93.3
2023	5,082	105.2	0.0729	5,346	4,956	97.5
2024	5,043	105.3	0.0866	5,311	4,851	96.2
2025	5,079	106.5	0.0902	5,410	4,922	96.9



D.1.4 G-J Locality ICAP to UCAP Translation

Table D.5 G-J Locality ICAP to UCAP Translation

Year	Forecast Peak Load (MW)	Locational Capacity Requirement (%)	Derate Factor	ICAP Requirement (MW)	UCAP Requirement (MW)	Effective UCAP (%)
2015	16,340	90.5	0.0577	14,788	13,934	85.3
2016	16,309	90.0	0.0793	14,678	13,514	82.9
2017	16,061	91.5	0.0731	14,696	13,622	84.8
2018	15,918	94.5	0.0626	15,042	14,100	88.6
2019	15,846	92.3	0.0514	14,625	13,874	87.6
2020	15,695	90.0	0.0418	14,124	13,534	86.2
2021	15,411	87.6	0.0361	13,498	13,011	84.4
2022	15,125	89.2	0.0476	13,492	12,850	85.0
2023	15,393	85.4	0.0471	13,145	12,526	81.4
2024	15,220	81.0	0.0703	12,328	11,462	75.3
2025	15,206	78.8	0.0660	11,982	11,192	73.6



D.2 Renewable/Intermittent Resources Impact on the NYCA IRM and UCAP Markets

Renewable generation with a limited ability to be dispatched is generally classified as an “intermittent" or "variable generation" resource. Intermittent resources generally include wind generation, solar, land-fill gas and small run-of-river hydro. The effective capacity of intermittent resource can be quantified and modeled using the GE-MARS program like conventional fossil-fired power plants. There are various modeling techniques to model intermittent generation resources in GE-MARS; the method that ICS has adopted uses historical New York hourly generation outputs for the previous five calendar years. This data can be scaled to create profiles for new intermittent generation facilities.

For intermittent resources, the nameplate capacity is the ICAP while the effective capacity is equal to the UCAP value. Seasonal variability and geographic location are factors that also affect intermittent resource availability. For instance, offshore wind will generally have higher availability and be more coincidence with peak load hours than land-based wind. The effective capacity of intermittent generation can be calculated statistically directly from historical hourly generation outputs, and/or by using the following information:

- Production hourly data.
- Maintenance cycle and duration
- EFOR (not related to fuel)

In general, the effective capacity of intermittent resources depends primarily on the availability of the resources “fuel source” – that is, wind, solar radiation, run-of-river water flow and availability of land-fill gas. Intermittent resources in New York on average have annual capacity factors that are based on their nameplate ratings. An intermittent resources output can range from close to nameplate under favorable “fuel” conditions to zero when the ”fuel” is unavailable.

One measure of an intermittent resource’s contribution to resource adequacy is its EFORd or derating factor. A derating factor is a reduction applied to a resource's capacity rating to account for its expected unavailability during critical periods, such as peak demand. In the context of NYISO capacity markets, a derating factor is used to convert a resource's nominal capacity (Adjusted ICAP) into Unforced Capacity (UCAP), which is the value that is actually traded in the capacity market. The derating factor is a function of factors like forced outage rates, the resource's performance history, and its specific characteristics, ensuring that the capacity sold is more reliably available when the system needs it most.

In general, intermittent resources have higher EFORds than conventional power resources. Increasing penetration of intermittent resources will result in increased reserve requirements and ICAP requirements while the UCAP requirements as % can change very little or even decline.   This is illustrated in Figure D1 which presents a plot of NYCA reserve margin as a % and NYCA UCAP requirement as a % vs. the NYCA derating factor. Figure D2 shows a rolling 5-year weighted average calculated NYCA derating factor (or EFORd) for intermittent resources.

Figure D1 Plot of % Reserve Margin & % UCAP Req. VS. Derating Factor

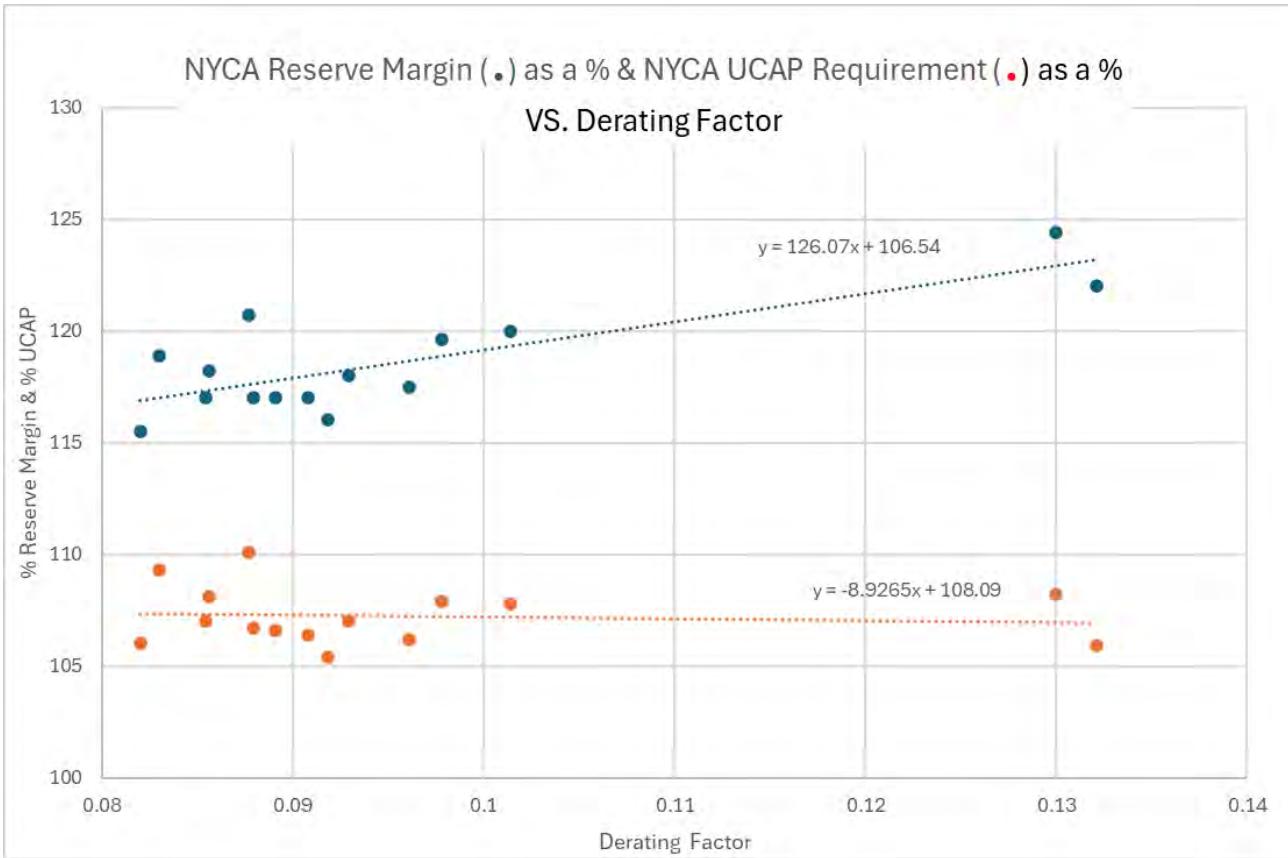
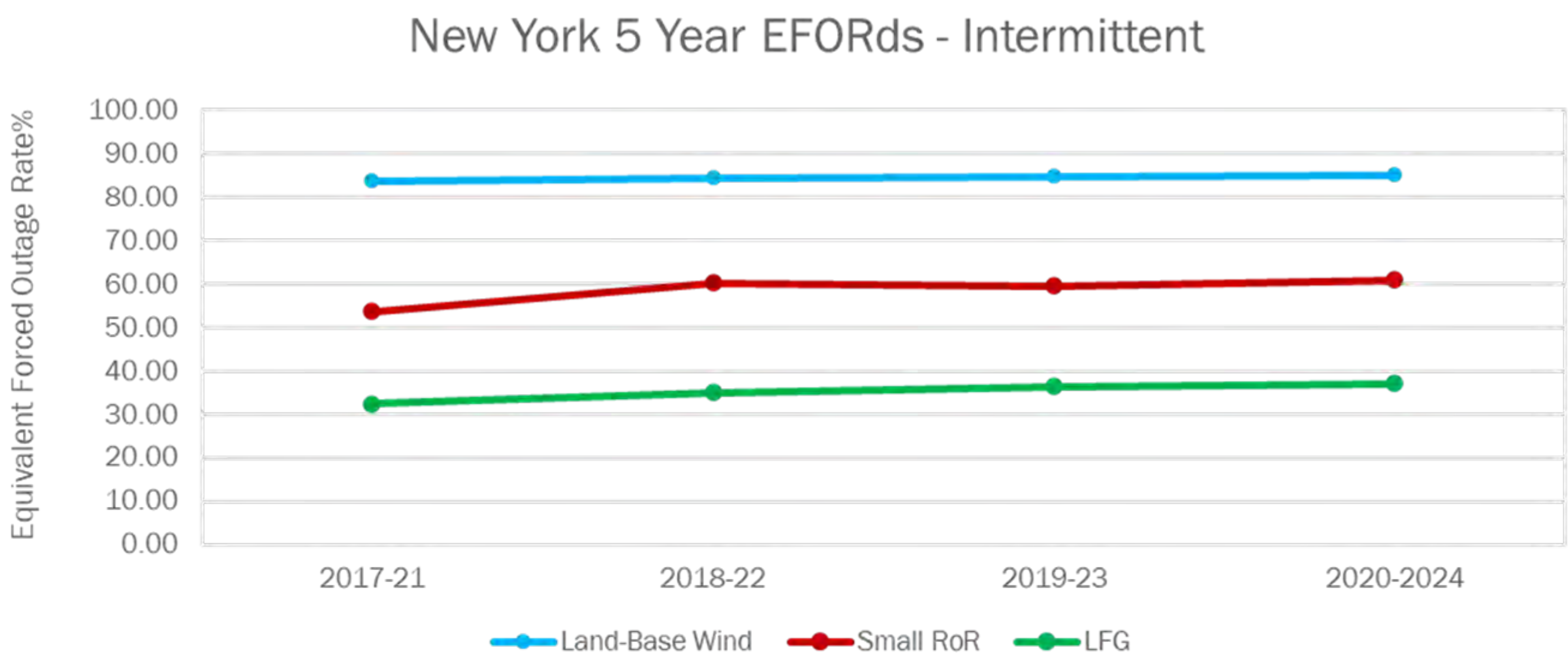


Figure D.2 Five-Year Weighted Annual Average EFORds - Intermittent Power Resources*



* Solar will be added when there are at least 3 units using production data for all 5 years of the average. Solar's annual capacity factor based on recently published data is on the order of 18% to 19% which implies a relatively high EFORd/derating factor.

Appendix E

Glossary of Terms

E. Glossary – Appendix E.

Term	Definition
Availability	A measure of time a generating unit, transmission line, or other facility can provide service, whether or not it actually is in service. Typically, this measure is expressed as a percent available for the period under consideration.
BTM Solar	Behind-the-meter (BTM) solar systems generate and consume electricity on-site at a home or business, positioned "behind" the utility's electric meter, to reduce reliance on the grid and lower energy bills. These systems are typically smaller and tailored to the specific site, often paired with battery storage to provide power when the sun isn't shining.
Bubble	A symbolic representation introduced for certain purposes in the GE-MARS model as an area that may be an actual zone, multiple areas or a virtual area without actual load.
Capability Period	Six (6) month periods which are established as follows: (1) from May 1 through October 31 of each year ("Summer Capability Period"); and (2) from November 1 of each year through April 30 of the following year ("Winter Capability Period"); or such other periods as may be determined by the Operating Committee of the NYISO. A summer capability period followed by a winter capability period shall be referred to as a "Capability Year." Each capability period shall consist of on-peak and off-peak periods.
Capacity	The rated continuous load-carrying ability, expressed in megawatts ("MW") or megavolt-amperes ("MVA") of generation, transmission or other electrical equipment.
Contingency	An actual or potentially unexpected failure or outage of a system component, such as a generator, transmission line, circuit breaker, switch, or other electrical element. A contingency also may include multiple components, which are related by situations leading to simultaneous component outages.
Control Area (CA)	An electric system or systems, bounded by interconnection metering and telemetry, capable of controlling generation to maintain its interchange schedule with other control areas and contributing to frequency regulation of the interconnection.
Demand	The rate at which energy must be generated or otherwise provided to supply an electric power system.
Distributed Energy Resource	Distributed Energy Resources (DERs) are diverse, small-scale technologies like solar panels, battery storage, and electric vehicles that generate, store, or manage electricity at or near the point of consumption. Unlike large, centralized power plants, DERs are located behind the electric meter, often on customer premises, to provide localized, flexible, and reliable power, improve energy efficiency, and increase grid resilience.
Emergency	Any abnormal system condition that requires automatic or immediate, manual action to prevent or limit loss of transmission facilities or generation resources that could adversely affect the reliability of an electric system.

Term	Definition
Energy Limited Resource (ELR)	Capacity resources, not including BTM:NG Resources, that, due to environmental restrictions on operations, cyclical requirements, such as the need to recharge or refill, or other non-economic reasons, are unable to operate continuously on a daily basis but are able to operate for at least four consecutive hours each day.
Expected Unserved Energy (EUE)	The expected amount of energy (MWh) of unserved load in a given time period (often one year) when a system's resources are insufficient to meet demand.
External Installed Capacity (External ICAP)	Installed capacity from resources located in control areas outside the NYCA that must meet certain NYISO requirements and criteria in order to qualify to supply New York LSEs.
Event-Day	An event-period lasting one day during which at least one Event-Hour occurs.
Event-Hour:	An event-period lasting one hour during which, at some point, system resources are insufficient to meet demand.
Firm Load	The load of a Market Participant that is not contractually interruptible. Interruptible Load – The load of a Market Participant that is contractually interruptible.
Generation	The process of producing electrical energy from other forms of energy; also, the amount of electric energy produced, usually expressed in kilowatt-hours (kWh) or megawatt-hours (MWh).
Installed Capacity (ICAP)	Capacity of a facility accessible to the NYS Bulk Power System, that is capable of supplying and/or reducing the demand for energy in the NYCA for the purpose of ensuring that sufficient energy and capacity is available to meet the reliability rules.
Installed Capacity Requirement (ICR)	The annual statewide requirement established by the NYSRC in order to ensure resource adequacy in the NYCA.
Installed Reserve Margin (IRM)	The amount of installed generating capacity above the expected annual net peak load, expressed as a percentage to meet demand and maintain reliability, even under certain contingencies. It is a measure of resource adequacy that ensures the power grid has sufficient capacity to maintain the target threshold reliability criterion of a loss-of-load expectation (LOLE) of 0.1 event days per year set by the regional regulatory bodies which for the New York Control Area (NYCA) are the Northeast Power Coordinating Council Inc (NPCC) and the New York State Reliability Council (NYSRC).
Interface	The specific set of transmission elements between two areas or between two areas comprising one or more electrical systems.
Load	The electric power that is used by devices connected to an electrical generating system. (IEEE Power Engineering)
Load Relief	Load reduction accomplished by voltage reduction or load shedding or both Voltage reduction and load shedding, as defined in this document, are measures by order of the NYISO.

Term	Definition
Load Shedding	The process of disconnecting (either manually or automatically) pre-selected customers' load from a power system in response to an abnormal condition to maintain the integrity of the system and minimize overall customer outages. Load shedding is a measure undertaken by order of the NYISO. If ordered to shed load, transmission owner system dispatchers shall immediately comply with that order. The load shall normally all be shed within 5 minutes of the order.
Load Serving Entity (LSE)	In a wholesale competitive market, Central Hudson Gas & Electric Corporation, Consolidated Edison Company of New York, Inc., Long Island Power Authority ("LIPA"), New York State Electric & Gas Corporation, Niagara Mohawk Power Corporation, Orange & Rockland Utilities, Inc., and Rochester Gas and Electric Corporation, the current forty-six (46) members of the Municipal Electric Utilities Association of New York State, the City of Jamestown, Rural Electric Cooperatives, the New York Power Authority ("NYPA"), any of their successors, or any entity through regulatory requirement, tariff, or contractual obligation that is responsible for supplying energy, capacity and/or ancillary services to retail customers within New York State.
Locality	A single electricity pricing Load Zone for capacity or a set of adjacent Load Zones within which a minimum level of Installed Capacity must be maintained, and as specifically identified in this document to mean (1) Load Zone J; (2) Load Zone K; and (3) Load Zones G, H, I, and J collectively (i.e., the G-J Locality).
Locational Capacity Requirement (LCR)	Due to transmission constraints, that portion of the NYCA ICAP requirement must be electrically located within a zone, in order to ensure that sufficient energy and capacity are available in that zone and that NYSRC Reliability Rules are met. Locational ICAP requirements are currently applicable to three transmission constrained zones, New York City, Long Island, and the Lower Hudson Valley, and are normally expressed as a percentage of each zone's annual peak load.
Loss of Load Hours (LOLH)	The expected number of loss of load Event-Hours in a given time period (often one year) when a system's resources are insufficient to meet demand.
Loss of Load expectation (LOLE)	The expected number of loss of load Event Days in a given time period (often one year) when a system's resources are insufficient to meet demand.
New York Control Area (NYCA)	The control area located within New York State which is under the control of the NYISO. See Control Area.
New York Independent System Operator (NYISO)	The NYISO is a not-for-profit organization formed in 1998 as part of the restructuring of New York State's electric power industry. Its mission is to ensure the reliable, safe and efficient operation of the State's major transmission system and to administer an open, competitive and nondiscriminatory wholesale market for electricity in New York State.
New York State Bulk Power System (NYS Bulk Power System or BPS)	The portion of the bulk power system within the New York Control Area, generally comprising generating units 300 MW and larger, and generally comprising transmission facilities 230 kV and above. However, smaller generating units and lower voltage transmission facilities on which faults and disturbances can have a significant adverse impact outside of the local area are also part of the NYS Bulk Power System.

Term	Definition
New York State Reliability Council, LLC (NYSRC)	An organization established by agreement (the "NYSRC Agreement") by and among Central Hudson Gas & Electric Corporation, Consolidated Edison Company of New York, Inc., LIPA, New York State Electric & Gas Corporation, Niagara Mohawk Power Corporation, Orange & Rockland Utilities, Inc., Rochester Gas and Electric Corporation, and the New York Power Authority, to promote and maintain the reliability of the Bulk Power System, and which provides for participation by Representatives of Transmission Owners, sellers in the wholesale electric market, large commercial and industrial consumers of electricity in the NYCA, and municipal systems or cooperatively-owned systems in the NYCA, and by unaffiliated individuals.
New York State (NYS) Transmission System	The entire New York State electric transmission system, which includes: (1) the transmission facilities under NYISO operational control; (2) the transmission facilities requiring NYISO notification, and; (3) all remaining facilities within the NYCA.
Net Peak Load	The highest point of gross peak electricity demand minus generation from non-dispatchable and unmetered variable renewable sources like solar and wind. It represents the electricity load that must be met by metered dispatchable resources such as natural gas, oil, nuclear or hydro power. Net peak load also includes metered variable renewable resources such as wind and solar with limited dispatchability.
Normalized Expected Unserved Energy	The Expected Unserved Energy (EUE) as a percent (%) of the total annual system net energy for load.
Operating Limit	The maximum value of the most critical system operation parameter(s) which meet(s): (a) pre-contingency criteria as determined by equipment loading capability and acceptable voltage conditions; (b) stability criteria; (c) post-contingency loading and voltage criteria.
Operating Procedures	A set of policies, practices, or system adjustments that may be automatically or manually implemented by the system operator within a specified time frame to maintain the operational integrity of the interconnected electric systems.
Operating Reserves	Resource capacity that is available to supply energy, or curtailable load that is willing to stop using energy, in the event of emergency conditions or increased system load and can do so within a specified time period.
Reserves	In normal usage, reserve is the amount of capacity available in excess of the demand.
Resource	The total contributions provided by supply-side and demand-side facilities and/or actions.
Special Sensitivity (SS)	All substantive assumption changes following approval of the final base case assumptions in early October are combined into a single SS Case. The SS Case is conducted using a Tan 45 analysis. As described in Policy 5, SS Cases must meet a specified levels of materiality before being designated as an SS case.

Term	Definition
Stability	The ability of an electric system to maintain a state of equilibrium during normal and abnormal system conditions or disturbances.
Thermal Limit	The maximum power flow through a particular transmission element or interface, considering the application of thermal assessment criteria.
Transfer Capability	The measure of the ability of interconnected electrical systems to reliably move or transfer power from one area to another over all transmission lines (or paths) between those areas under specified system conditions.
Transmission District	The geographic area served by the NYCA investor-owned transmission owners and LIPA, as well as customers directly interconnected with the transmission facilities of NYPA.
Transmission Owner (TO)	Those parties who own, control and operate facilities in New York State used for the transmission of electric energy in interstate commerce. Transmission owners are those who own, individually or jointly, at least 100 circuit miles of 115 kV or above in New York State and have become a signatory to the TO/NYISO Agreement.
Unforced Capacity:	The measure by which Installed Capacity Suppliers will be rated, in accordance with formulae set forth in the ISO Procedures, to quantify the extent of their contribution to satisfy the NYCA Installed Capacity Requirement, and which will be used to measure the portion of that NYCA Installed Capacity Requirement for which each LSE is responsible.
Voltage Limit	The maximum power flow through some particular point in the system considering the application of voltage assessment criteria.
Voltage Reduction	A means of achieving load reduction by reducing customer supply voltage, usually by 3, 5, or 8 percent. If ordered by the NYISO to go into voltage reduction, Transmission Owner system dispatchers shall immediately comply with that order. Quick response voltage reduction shall normally be accomplished within ten (10) minutes of the order.
Zone	A defined portion of the NYCA area that encompasses a set of load and generation buses. Each zone has an associated zonal energy price that is calculated as a weighted average price based on generators' marginal energy price and generator bus load distribution factors. A "zone" outside the NY control area is referred to as an external zone. Currently New York State is divided into eleven Load Zones, corresponding to ten major transmission interfaces that can become congested.