Appendices

New York Control Area Installed Capacity Requirement

For the Period May 2024 To April 2025

December 8, 2023

New York State Reliability Council, LLC
Installed Capacity Subcommittee

Table of Contents

Table of Tables & Figures

Appendices

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 2023-24 and 2024-25 IRM reports (a.k.a. the 2024 IRM report).

Figure A.1 NYCA ICAP Modeling

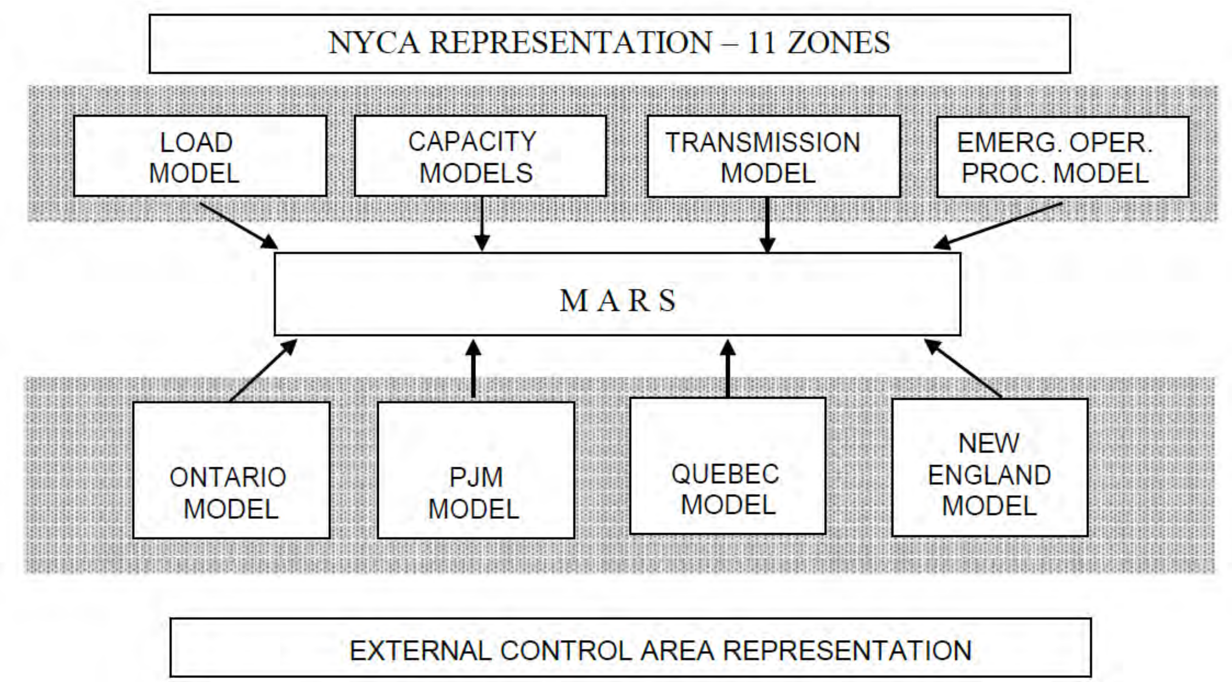


Table A.1 Modeling Details

#	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 2023 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] 2023 Load and Capacity Data Report, http://www.nyiso.com/public/markets_operations/services/planning/documents/index.jsp

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 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 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 (days/year and 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.

A.1.1 Error Analysis

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%.

For this analysis, the Base Case required 1,048 replications to converge to a standard error of 0.05 and required 3,231 replications to converge to a standard error of 0.025. For our cases, the model was run to 3,250 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 confidence interval at this point ranges from 22.9% to 23.3%. An IRM of 23.1% is in full compliance with the NYSRC Resource Adequacy rules and criteria (see Base Case Study Results section).

A.1.2 Conduct of the GE-MARS analysis

The study was performed using Version 4.13.2129 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 Methodology

The 2024 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: ax2+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	2023 Study Assumption	2024 Study Assumption	Explanation
Peak Load	October 1, 2022 NYCA: NYCA: 32,246.0 MW NYC: 11,285.0 MW LI: 5,133.3 MW G-J: 15,406.8 MW	October 1, 2023 NYCA: NYCA: 31,765.6 MW NYC: 11,170.6 MW LI: 5,080.3MW G-J: 15,273.5 MW	Forecast based on examination of 2023 weather normalized peaks, 2024 economic and expected weather projections, and Transmission Owner projections.
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)**	Load shapes updated for the 2023 IRM study to be more reflective of current system conditions such as solar penetration
Load Uncertainty Model	Statewide and zonal models updated to reflect current data	Statewide and zonal models updated to reflect current data	Updated from 2023 IRM. Based on TO and NYISO data and analyses.

A.3.2 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 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 2023 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 2023 Transmission District weather adjustments, which normalize the peaks to typical summer peak weather conditions. For purposes of the IRM and ICAP forecasts, the NYISO evaluates the system peak load that occurs during non-holiday weekdays in July and August. In 2023, the system peak load during this period was on July 28th, Hour Beginning 17. The system peak load of 28,722.9 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 2022 weather normalized peak load of 31,397.5 MW (col. 4). Notably, there were a number of hot weather high load days in early September of 2023. The September peak load of 30,206 MW on September 6th exceeded the IRM and ICAP peak window peak load in July. The load and weather data from the early September high load days was considered in the determination of final 2023 Transmission District weather adjustments for the 2024 IRM forecast.

Some Transmission Owners developed updated estimates of the Regional Load Growth Factor (RLGF) for their territories. The RLGF represents the ratio of forecasted 2024 summer peak load to the 2023 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 2023 Gold Book forecast were used for those Transmission Owners that did not provide updates. The final RLGFs (col. 6) were reviewed by the NYISO and discussed with the Transmission Owners as needed. The 2024 forecast before adjustments (col. 7) is the product of the 2023 weather normalized peaks excluding large loads and the RLGFs. Summer 2024 large load projections are added in column 8. The resulting sum (col. 9) represents the 2024 IRM coincident peak forecast of 31,616.8 MW before Behind-the-Meter Net Generation (BTM:NG) adjustments. This forecast is a 2.1% decrease relative to the 2024 forecast from the 2023 Gold Book. For purposes of modeling in the IRM study, the forecast of BTM:NG resource load is added in column 10, producing a total forecast of 31,765.6 MW inclusive of BTM:NG load (col. 11).

The Locality forecasts are reported in the second table below. 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. The Locality NCP to CP ratios were calculated using the historical 15-year ratio (excluding outlier years). The Locality forecasts of 11,170.6 MW (Zone J), 5,080.3 MW (Zone K), and 15,273.5 MW (G-J Locality), inclusive of BTM:NG loads, are shown in column 10.

The third table below shows the 2024 non-coincident peak load forecast by Zone. Zonal coincident peak forecasts were generally derived using sub-zonal load shares (Transmission District to Zone), based upon peak and near-peak load hours over the most recent five summers. Zonal non-coincident peak forecasts were calculated by multiplying the coincident peak forecast by the Zonal NCP to CP ratios. The Zonal forecasts shown below include the projected impacts of BTM:NG and large load projects.

The peak load forecasts, along with the regression models, weather adjustments, RLGFs, and NCP to CP ratios used to derive them were discussed and approved by the NYISO Load Forecasting Task Force (LFTF) and the NYSRC Installed Capacity Subcommittee (ICS). The LFTF recommended the Final 2024 Peak Load Forecast presented below to the NYSRC. The ICS approved the Final 2024 Peak Load Forecast for use in the 2024 IRM study.

Table A.4 2024 Final NYCA Peak Load Forecast – Coincident Peak

2024 IRM Coincident Peak Forecast										
(1)	(2)	(3)	(4) =(2)+(3)	(5)	(6)	(7) =(5)*(6)	(8)	(9) =(7)+(8)	(10)	(11) =(9)+(10)
Transmission District	2023 Actual MW, 7/28/2023 HB 17	Total Adjustment (Demand Response + Muni Self-Gen + Wthr Adjustment) MW	2023 Weather Normalized Coincident Peak MW	2023 WN Peak MW Excluding Large Loads	Regional Load Growth Factor	2024 Forecast, Before Adjustments MW	Large Loads MW	2024 IRM Forecast, With Large Loads, Before BTM:NG Adjustments MW	BTM:NG Forecast MW	2024 IRM Forecast, With Large Load Growth and BTM:NG Adjustments MW
Con Edison	11,054.4	1,473.2	12,527.6	12,527.6	1.0029	12,563.9	0.0	12,563.9	15.2	12,579.1
Cen Hudson	986.0	62.0	1,048.0	1,048.0	0.9940	1,041.7	0.0	1,041.7	0.0	1,041.7
LIPA	4,953.4	124.4	5,077.8	5,077.8	0.9770	4,961.0	0.0	4,961.0	38.9	4,999.9
Nat. Grid	6,030.5	627.5	6,658.0	6,655.6	1.0000	6,655.6	259.0	6,914.6	5.0	6,919.6
NYPA	484.0	3.5	487.5	335.1	1.0030	336.1	169.0	505.1	0.0	505.1
NYSEG	2,887.7	158.1	3,045.8	3,045.8	0.9979	3,039.4	50.0	3,089.4	44.1	3,133.5
O&R	974.4	105.3	1,079.7	1,079.7	0.9940	1,073.2	0.0	1,073.2	0.0	1,073.2
RG&E	1,352.5	120.6	1,473.1	1,473.1	0.9965	1,467.9	0.0	1,467.9	45.6	1,513.5
NYCA	28,722.9	2,674.6	31,397.5	31,242.7	0.9967	31,138.8	478.0	31,616.8	148.8	31,765.6

2024 Forecast from 2023 Gold Book	32,280.0
Change from 2023 Gold Book	-663.2
Percent Change	-2.1%

Table A.5 2024 Final NYCA Peak Load Forecast – Locality Peaks

2024 IRM Locality Peak Forecasts									
(1)	(2)	(3)	(4)	(5) = (3) * (4)	(6)	(7) = (6) - (5)	(8) = (7) / (6)	(9)	(10) = (8) + (9)
Locality	2023 Locality Peak MW	2023 Weather Normalized Locality Peak MW	Regional Load Growth Factor	2024 IRM Locality Peak Forecast Before BTM:NG Adjustments MW	2024 Forecast from 2023 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
Zones G-to-J	13,588.6	15,235.2	1.0015	15,258.3	15,416.0	-157.7	-1.0%	15.2	15,273.5
Zone J - NYC	10,064.0	11,123.2	1.0029	11,155.4	11,280.0	-124.6	-1.1%	15.2	11,170.6
Zone K - LIPA	4,955.6	5,160.1	0.9770	5,041.4	5,049.0	-7.6	-0.2%	38.9	5,080.3

Table A.6 2024 Final NYCA Peak Load Forecast – Zonal Peaks

Zonal Non-Coincident Peak Forecasts With BTM:NG Adjustments										
A	B	C	D	E	F	G	H	I	J	K
2,764.0	2,095.9	2,766.8	711.5	1,360.7	2,324.8	2,177.2	638.9	1,410.0	11,170.6	5,080.3

Zonal Load Forecast Uncertainty

The 2024 load forecast uncertainty (LFU) models were updated during the spring of 2023. The NYISO and pertinent Transmission Owners developed updated load-weather regression models inclusive of summer 2022 data, resulting in updated LFU multipliers for use in the 2024 IRM study. As with the 2023 IRM study, the equal-area approach was used to determine the reference temperatures of each of the seven LFU bins, which reflect the assumed normal distribution of the weather variable. This was done by setting the Z-value equal to the location of the midpoint of the area of each bin.

Review of Load-Weather Relationship

Updated regression models were developed for all LFU modeling regions (Zones A-E, Zones F&G, Zones H&I, Zone J, and Zone K) to establish the recent load-weather relationship. The NYISO developed models for the Zones A-E and Zones F&G regions. Models for the Zones H&I and Zone J areas were developed in conjunction with Con Edison. The Zone K model was developed by LIPA and reviewed by the NYISO. The NYISO developed a system-level winter LFU model reflecting the load-weather relationship observed during the 2022-23 winter. All model results were presented to and reviewed by the LFTF and ICS. The ICS approved the updated 2023 LFU model results for use in the 2024 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. The LIPA Zone K splined linear model utilized data from the 2013 through 2022 summers.

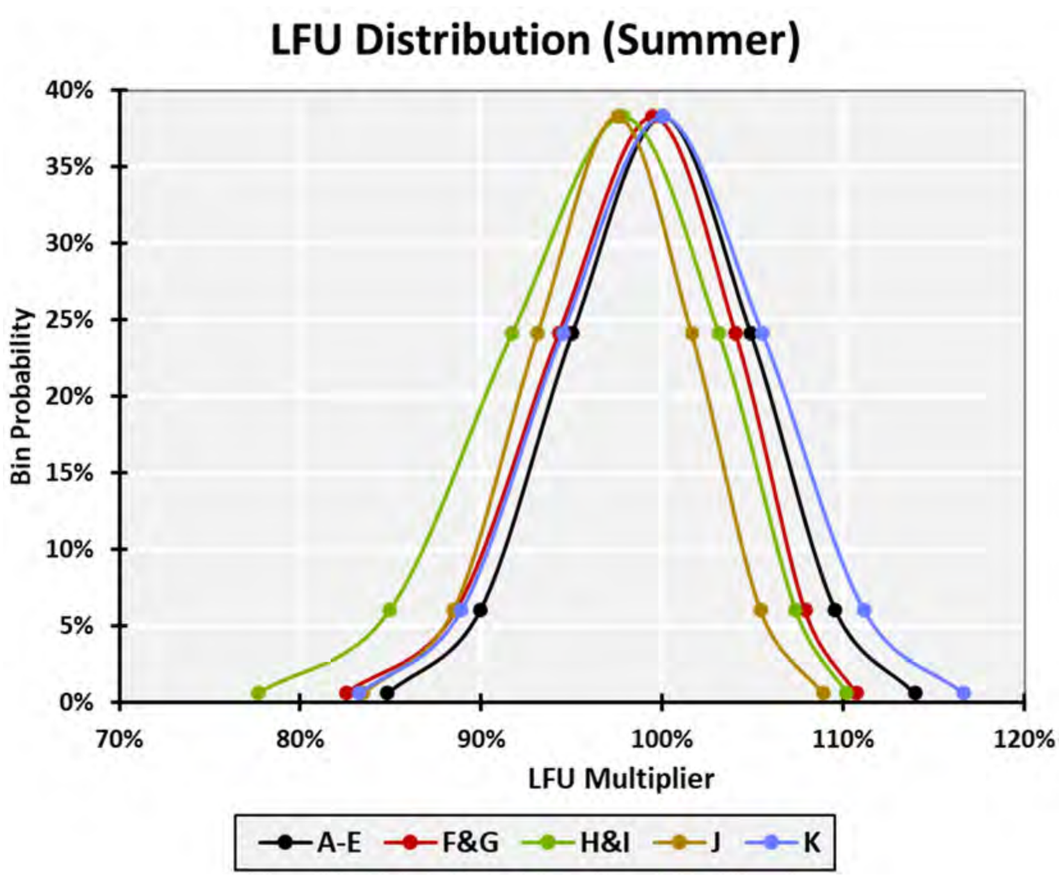
The NYCA winter model utilized a 2nd order polynomial regression fit through winter 2018-19, 2021-22, & 2022-23 load and weather data. The winter LFU model used the winter weather variable developed as part of the LFU phase 3 analyses, based on temperature and wind speed.

The 2024 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.

Table A.7 2024 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%	110.37%
Bin 2	1.79	6.06%	109.54%	107.86%	107.34%	105.42%	111.14%	106.37%
Bin 3	0.89	24.17%	104.86%	104.04%	103.09%	101.61%	105.52%	102.75%
Bin 4	0.00	38.29%	100.00%	99.46%	97.81%	97.51%	100.00%	99.42%
Bin 5	-0.89	24.17%	95.00%	94.29%	91.70%	93.12%	94.48%	96.29%
Bin 6	-1.79	6.06%	89.91%	88.61%	84.93%	88.45%	88.89%	93.30%
Bin 7	-2.74	0.62%	84.79%	82.53%	77.65%	83.48%	83.27%	90.41%

Figure A.2 Sumer LFU Distributions



Additional Discussion on the 2024 LFU Models

The Load Forecast Uncertainty (LFU) models measure the load response to weather at high 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.

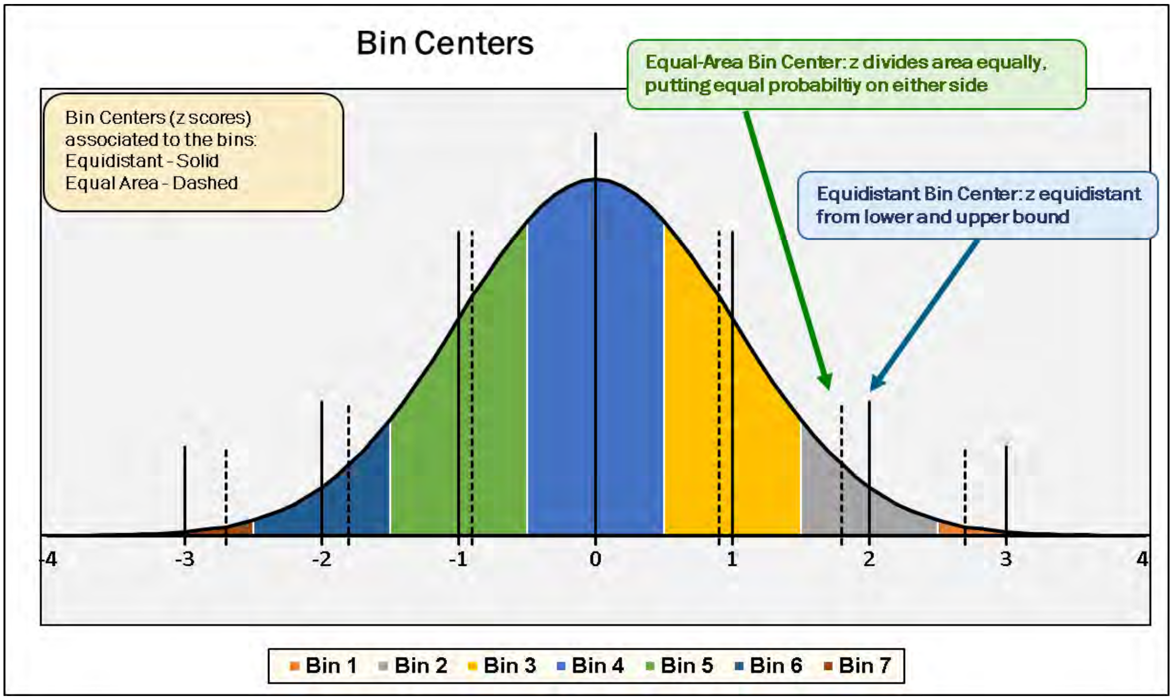
LFU multipliers are largely driven by the slope of load vs. temperature, or the weather response of load. If the weather response of load increases, the slope of load vs. temperature will increase, and the upper-bin LFU multipliers (Bins 1-3) will increase. The 2023 LFU multipliers include summer 2022 data. Based upon the updated data and LFU modeling, the summer load response to weather at high temperatures was flatter in Zones F&G, Zones H&I, and Zone J, resulting in lower LFU multipliers at the upper bins relative to the 2023 IRM study. The summer load response to weather at high temperatures was steeper in Zones A-E and Zone K, resulting in higher Bin 1 LFU multipliers relative to the prior IRM study.

The Con Edison and Orange & Rockland 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 A-to-E and Zone K LFU areas, above 50th percentile for Zones F&G and Zones H&I, and 67th percentile for Zone J. The NYCA aggregate design condition reflected in the winter LFU multipliers is the 57th percentile.

LFU Bin Z-Values

Beginning with the LFU models used in the 2022 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.

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



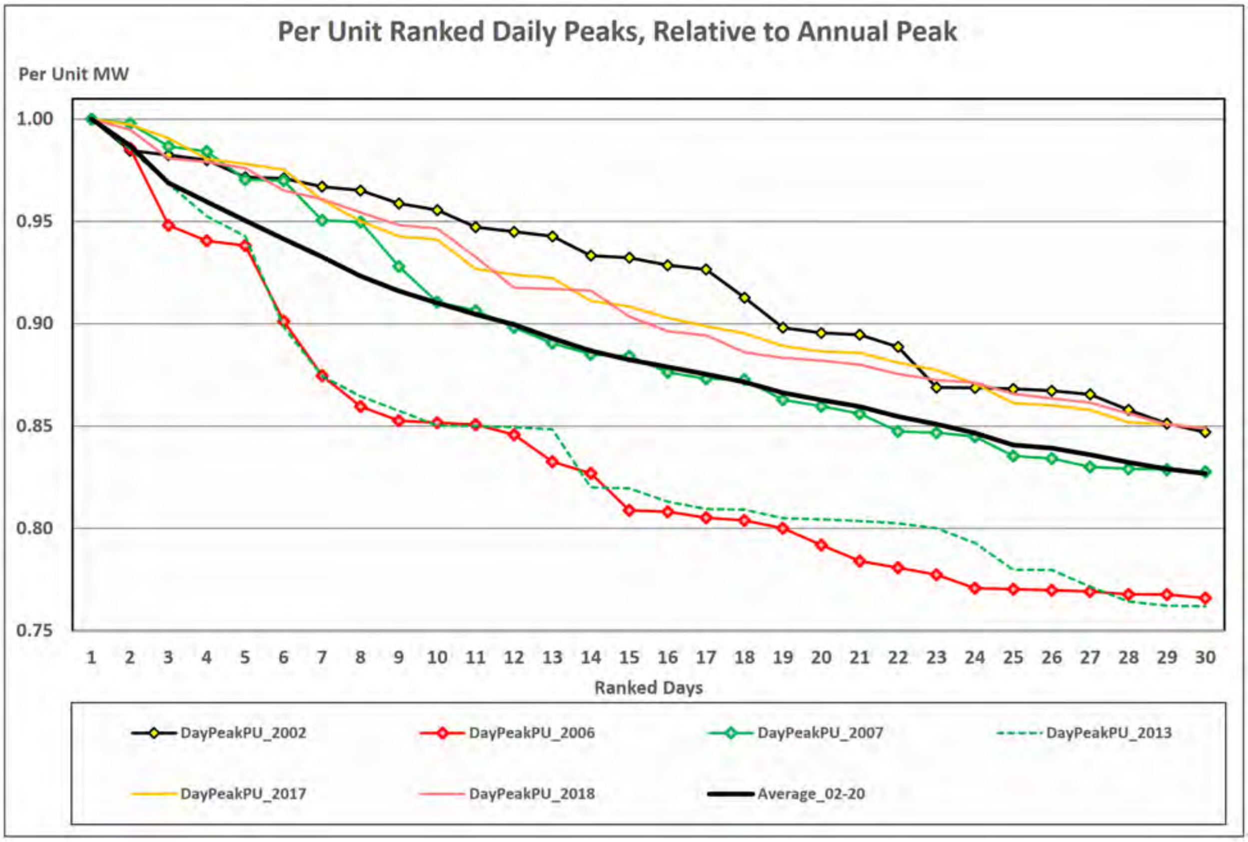
Review of Historical Zonal Load Shapes for Load Bins

Beginning with the 2014 IRM study, multiple years of historical load shapes were assigned to the load forecast uncertainty bins. 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 analyses, the NYISO recommended and the ICS approved the use of the 2013, 2017, and 2018 load shapes beginning with the 2023 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 solar in future years. Behind-the-meter (BTM) solar is not modeled as a resource in the 2024 IRM study. Therefore, the 2013, 2017, and 2018 historical load shapes were adjusted by scaling up the underlying BTM solar impacts from those years to reflect the load shapes that would result with the projected 2024 BTM solar capacity. The 2024 IRM study will thus reflect the average impact of increasing BTM solar penetration on load levels and daily shapes, through use of BTM solar-adjusted historical load shapes.

A.3.3 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 2023 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 2024 IRM study.

Table A.8 Capacity Resources

Parameter	2023 Study Assumption	2024 Study Assumption	Explanation
Generating Unit Capacities	2022 Gold Book values. Use min (DMNC vs. CRIS) capacity value	2023 Gold Book values. Use min (DMNC vs. CRIS) capacity value	2023 Gold Book publication
Planned Generator Units	0 MW of project related new thermal resources or re-ratings.	0 MW of projects related to new thermal resources or re-ratings.	NYISO recommendation based on documented process[2]
Wind Resources	539.3 MW of Land-Based Wind Capacity additions totaling 2,351.1 MW of qualifying wind	136 MW of Offshore Wind Capacity additions totaling 2,502.3 MW of qualifying wind	Renewable units based on RPS agreements, interconnection queue, and ICS input.
Wind Shape	Actual hourly plant output over the period 2017-2021. New units will use zonal hourly averages or nearby units.	Actual hourly plant output over the period 2018-2022. New units will use zonal hourly averages or nearby units. Normalized offshore wind shapes as published by NYISO over the period 2017-2021	Program randomly selects a wind shape of hourly production over the years 2017-2022 for each model iteration.

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

Parameter	2023 Study Assumption	2024 Study Assumption	Explanation
Solar Resources (Grid connected)	0 MW of Solar Capacity additions totaling 214.4 MW of qualifying Solar Capacity.	90 MW of Solar Capacity additions with solar totaling 304.4 MW of qualifying installed Solar Capacity.	ICAP Resources connected to Bulk Electric System
Solar Shape	Actual hourly plant output over the period 2017-2021. New units will use zonal hourly averages or nearby units.	Actual hourly plant output over the period 2018-2022. New units will use zonal hourly averages or nearby units.	Program randomly selects a solar shape of hourly production over the years 2018-2022 for each model iteration.
BTM- NG Program	No new BTM NG resources Forecast load adjustment of 161.6 MW	One new BTM NG recourse: Oxbow (Zone A) – 3.2 MW, with the total of 148.8 MW Forecast load adjustment of 148.8 MW	Both the load and generation of the BTM:NG Resources are modeled.
Retirements, Mothballed units, and ICAP ineligible units	1,205.2 MW of unit deactivations	-140.1 MW of unit deactivations	2023 Gold Book publication and generator notifications
Forced and Partial Outage Rates	Five-year (2017-2021) GADS data for each unit represented. Those units with less than five years – use representative data.	Five-year (2018-2022) 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 (2018-2022)

Parameter	2023 Study Assumption	2024 Study Assumption	Explanation
Planned Outages	Based on schedules received by the NYISO. Removed for the 2023 IRM study.	Based on schedules received by the NYISO. Not modeled for the 2024 IRM study.	Based on 2021 Final Base Case
Summer Maintenance	Nominal 50 MW – divided equally between Zones J & K	Nominal 50 MW – divided equally between 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 2017-2021.	Actual hourly plant output over the period 2018-2022.	Program randomly selects a Hydro shape of hourly production over the years 2017-2021 for each model iteration.
Large Hydro	Probabilistic Model based on 5 years of GADS data 2017-2021	Probabilistic Model based on 5 years of GADS data 2018-2022	Transition Rates representing the Equivalent Forced Outage Rates (EFORd) during demand periods over the most recent five-year period (2016-2020)
Energy Limited Resources (ELR)	Based upon elections made by August 1, 2022	Based upon elections made by August 1, 2023.	Existing elections are made by August 1st and will be incorporated into the model.

(1) <u>Generating Unit Capacities</u>

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 CRIS (Capacity Resource Interconnection Service) 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 2023 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 of new thermal units and unit re-ratings (summer ratings).

(3) Wind Modeling

Wind generators are modeled as hourly load modifiers using hourly production data over the period 2018-2022. 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 2,486.5 MW of installed capacity is associated with wind generators.

Table A.9 Wind Generation

Wind				
Resource	Zone	CRIS (MW)	Summer Capability (MW)	MARS Modeled Capability**
Bliss Wind Power [WT]	A	100.5	100.5	100.5
Canandaigua Wind Power [WT]	C	125.0	125.0	125.0
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	126.0	126.0	126.0
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	81.0	81.0	81.0
Jericho Rise Wind Farm [WT]	D	77.7	77.7	77.7
Marble River Wind [WT]	D	215.2	215.2	215.2
Hardscrabble Wind [WT]	E	74.0	74.0	74.0
Madison Wind Power [WT]	E	11.5	11.6	11.5
Maple Ridge Wind [WT01]	E	231.0	231.0	231.0
Maple Ridge Wind [WT02]	E	90.7	90.8	90.7
Munnsville Wind Power [WT]	E	34.5	34.5	34.5
Arkwright Summit Wind Farm [WT]	A	78.4	78.4	78.4
Eight Point Wind Energy Center [WT]	C	101.2	111.2	101.2
Bluestone Wind [WT]	E	111.8	111.8	111.8
Number 3 Wind Energy [WT]	E	103.9	103.9	103.9
Ball Hill Wind [WT]	A	100.0	100.0	100.0
Baron Winds [WT]	C	300.0	121.8	121.8
South Fork Wind Farm (Off-Shore)	K	96.0	96.0	96.0
South Fork Wind Farm II (Off-Shore)	K	40.0	40.0	40.0
Total		2667.2	2502.3	2486.5

(4) Solar Modeling

Solar generators are modeled as hourly load modifiers using hourly production data over the period 2018-2022. Each calendar production year represents an hourly solar shape for each solar facility which the GE-MARS program will randomly select from. A total of 304.4 MW of solar capacity was modeled.

(5) Retirements/Deactivations/ ICAP Ineligible

There are 6 units totaling -140.1 MW that were in the 2023 IRM study as being deactivated that rescinded their plans to cease operating. They are modeled as operating for the 2024 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, 2023 for the Capability Year beginning on May 1, 2024). 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 2024 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, and the 315 MW Linden Variable Frequency Transformer. 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 2024 IRM study incorporates the confidential elections that these facility owners made for the 2024-25 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.

(7) Energy Limited Resources

The capacity model now 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 were 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, 2023 for the Capability Year beginning on May 1, 2024).

(8) 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 "equivalent demand forced outage rate" (EFORd) for each unit represented. 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 2024 IRM study.

Figure A.5 shows a rolling 5-year average of the same data.

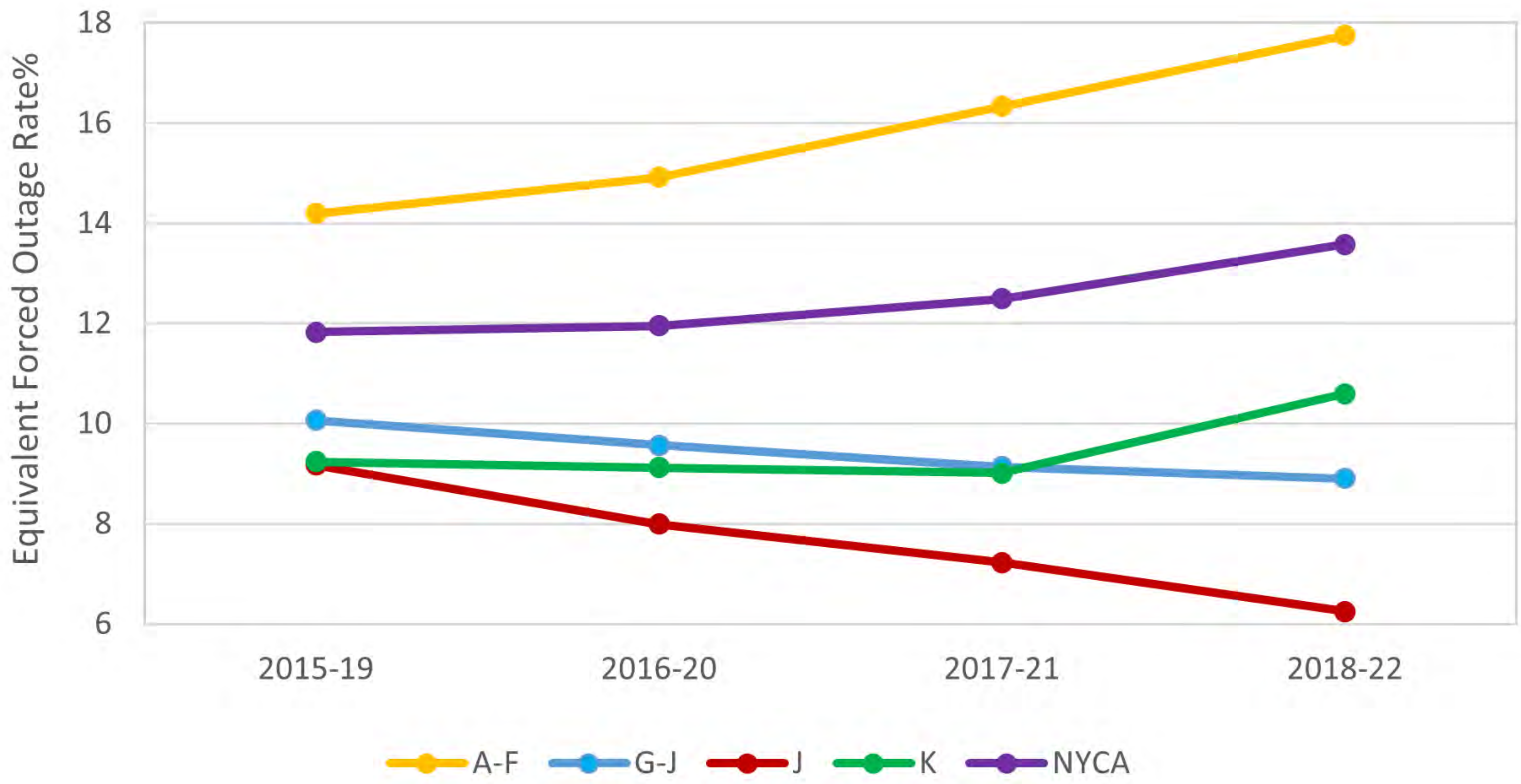
Figures A.6 and A.7 show the availability trends of the NYCA broken out by fuel type.

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 2016 through 2020. 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 Five-Year Weighted Annual Average 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.

Figure A.6 NYCA Annual Weighted Average Availability

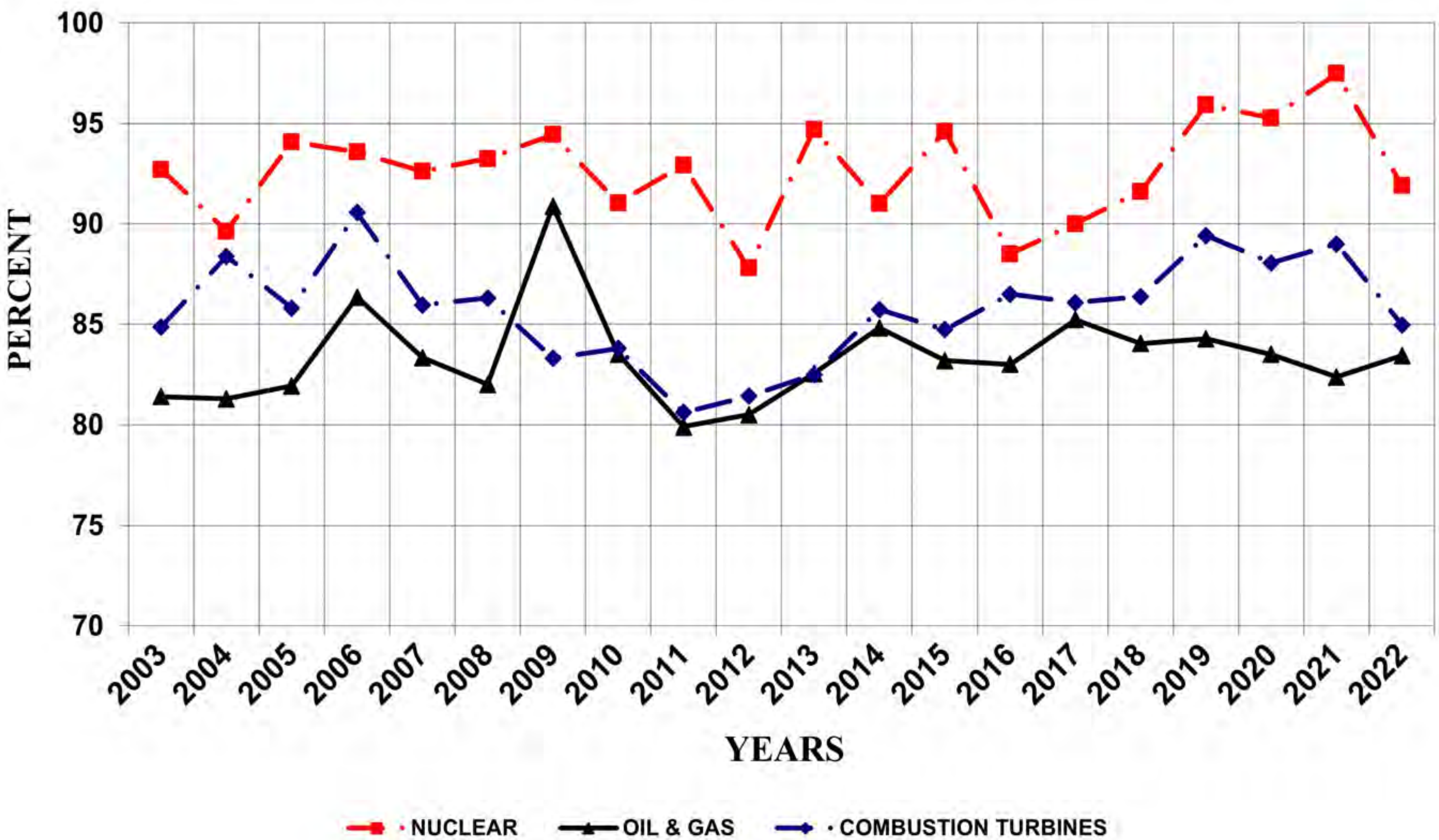


Figure A.7 NYCA Five-Year Weighted Average Availability

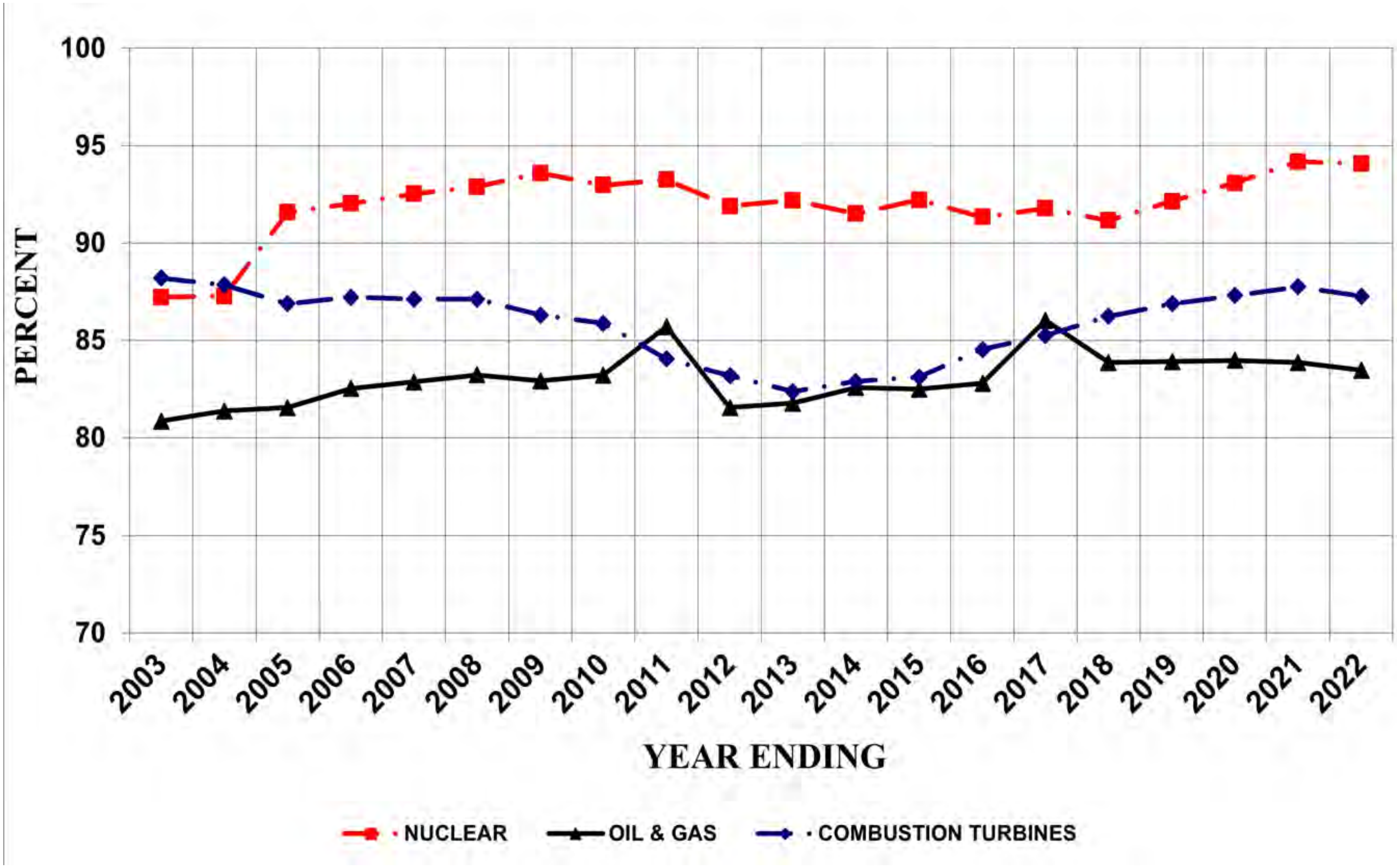


Figure A.8 NERC Weighted Annual Average Availability

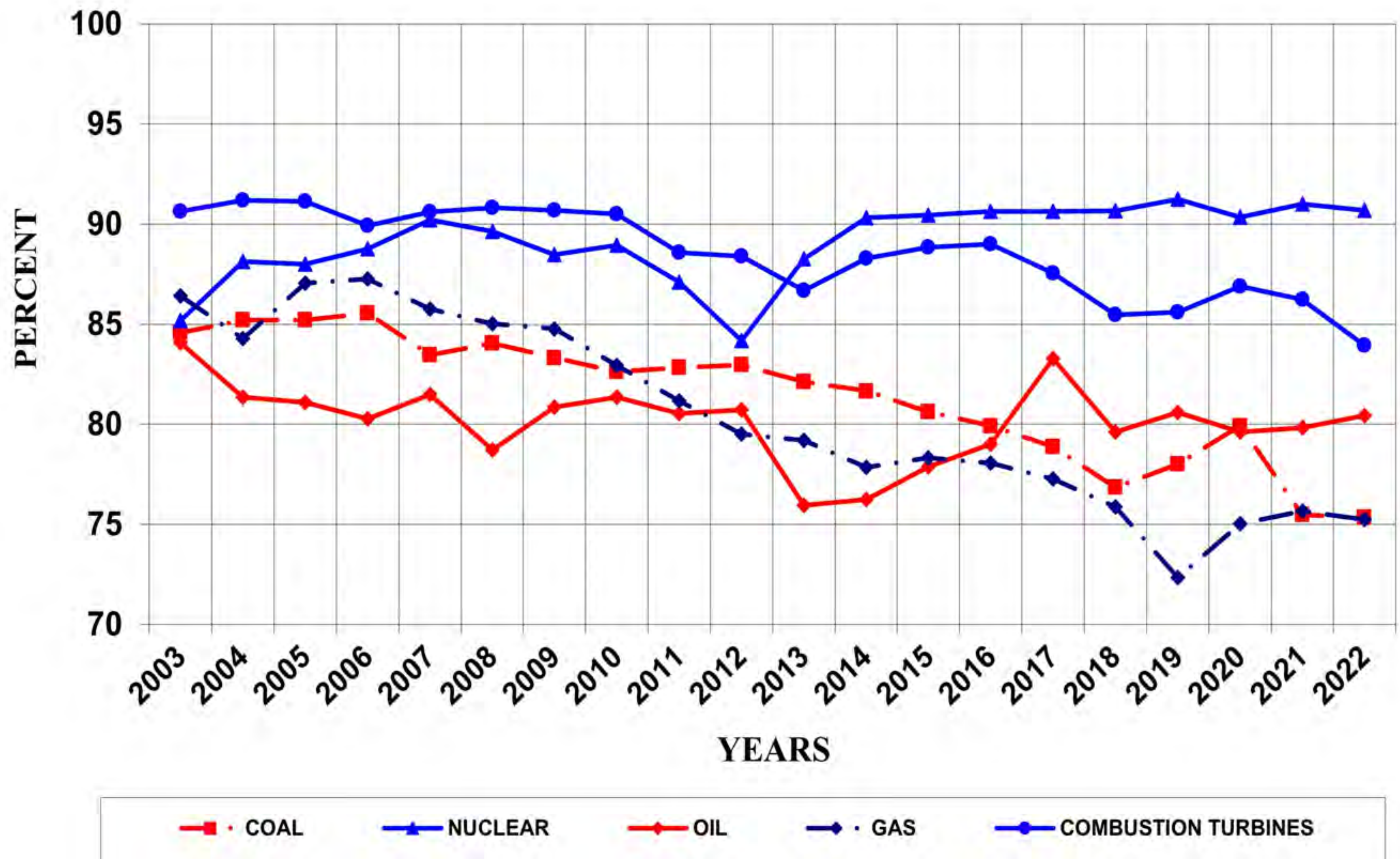
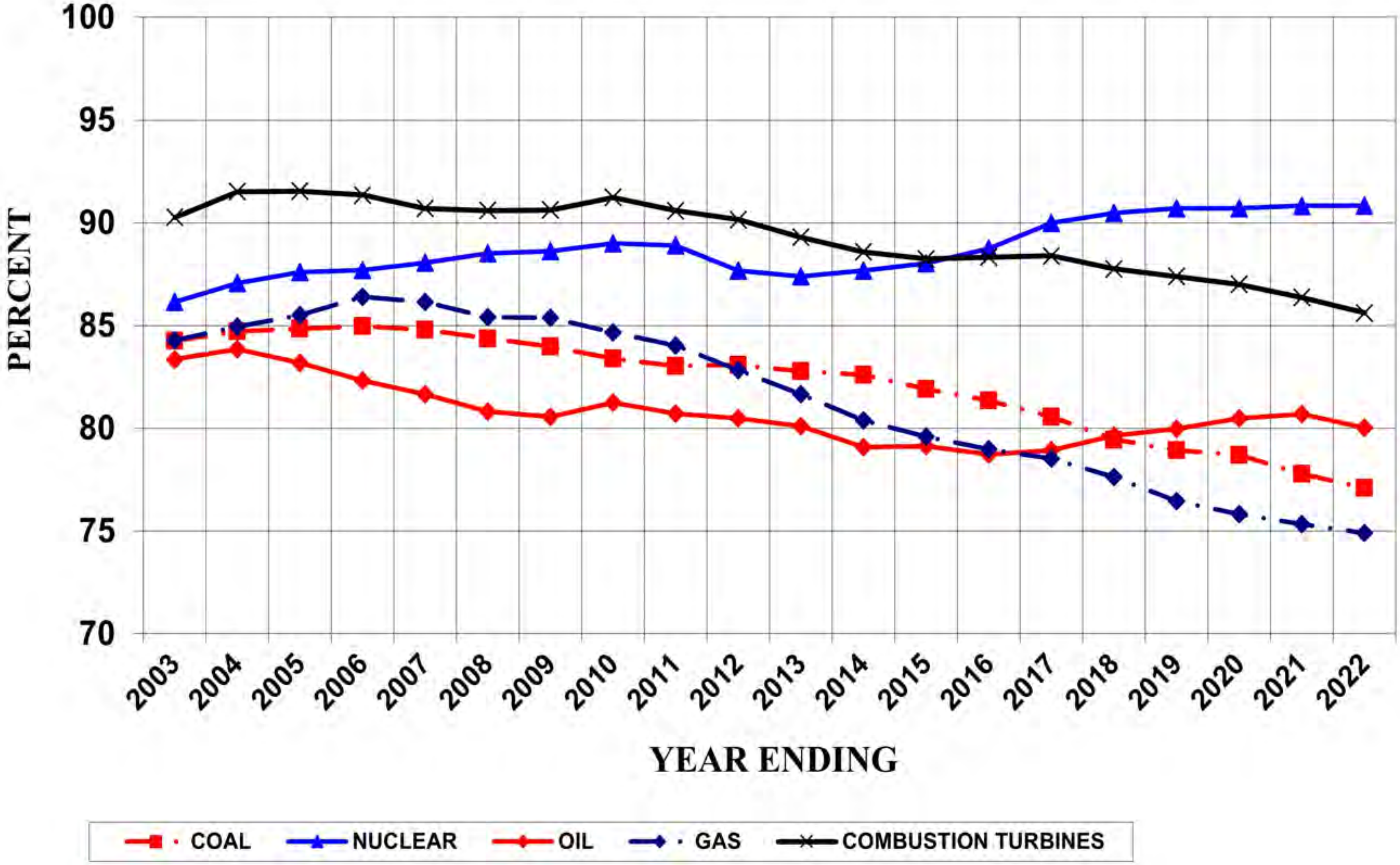


Figure A.9 NERC Five-Year Weighted Average Availability



(9) Outages and Summer Maintenance

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

(10) 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.

(11) Large Hydro De-rates

Hydroelectric projects are modeled consistent with the treatment of thermal units, with a probability capacity model based on five years of unit performance. 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 entitled: Capacity Resources.

A.3.4 Transmission System Model

A detailed transmission system model is represented in the GE-MARS topology. The transmission system topology, which includes eleven NYCA Zones and four External Control Areas, along with transfer limits, is shown in Figure A.10. The transfer limits employed for the 2024 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 NYISO's Transmission Planning and Advisory Subcommittee (TPAS) also reviewed and approved the topology. A list of those studies is shown in Table A.10, below. The transfer limits are further refined by other assessments conducted by the NYISO. The assumptions for the transmission model included in the 2024 IRM study are listed in Table A.10, which reflects changes from last year's model. The changes that are captured in this year's model are: 1) Segment B of AC Transmission project expected to be in service by December 2023 which increases the transfer limits of a number of interfaces; but increases in certain transfer limits also reflect the delay of the construction of Dover phase angle regulator (PAR) beyond June 2024;[3] 2) a small update to Dysinger East limit and Zone A Group limit as well as Dunwoodie and Y40/50 Group limit based on updated assumptions in the applicable planning study; 3) changes to various LIPA transfer limits based on updated transfer assumptions between Long Island and New York City, as well as decreases in load in the West of Newbridge area.

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 five 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 TOs provided updated transition rates for their associated cable interfaces.

[3] The delay of Dover PAR construction results in reduction in the transfer limits of Central East, Central East + Marcy South group, and will also result in a reduction to the UPNYSENY transfer limit, compared to the full in service of AC Transmission project condition. The specific reduction to the UPNYSENY transfer limit resulting from the delay of the Dover PAR was not identified by the NYISO for inclusion in the assumptions for the 2024 IRM study. The NYISO tested various scenarios of the UPNYSENY transfer limit and concluded that the transfer limit reduction on UPNYSENY is not expected to impact the IRM study results. Therefore, the UPNYSENY interface limit is modeled as if the Segment B of AC Transmission project is fully in service.

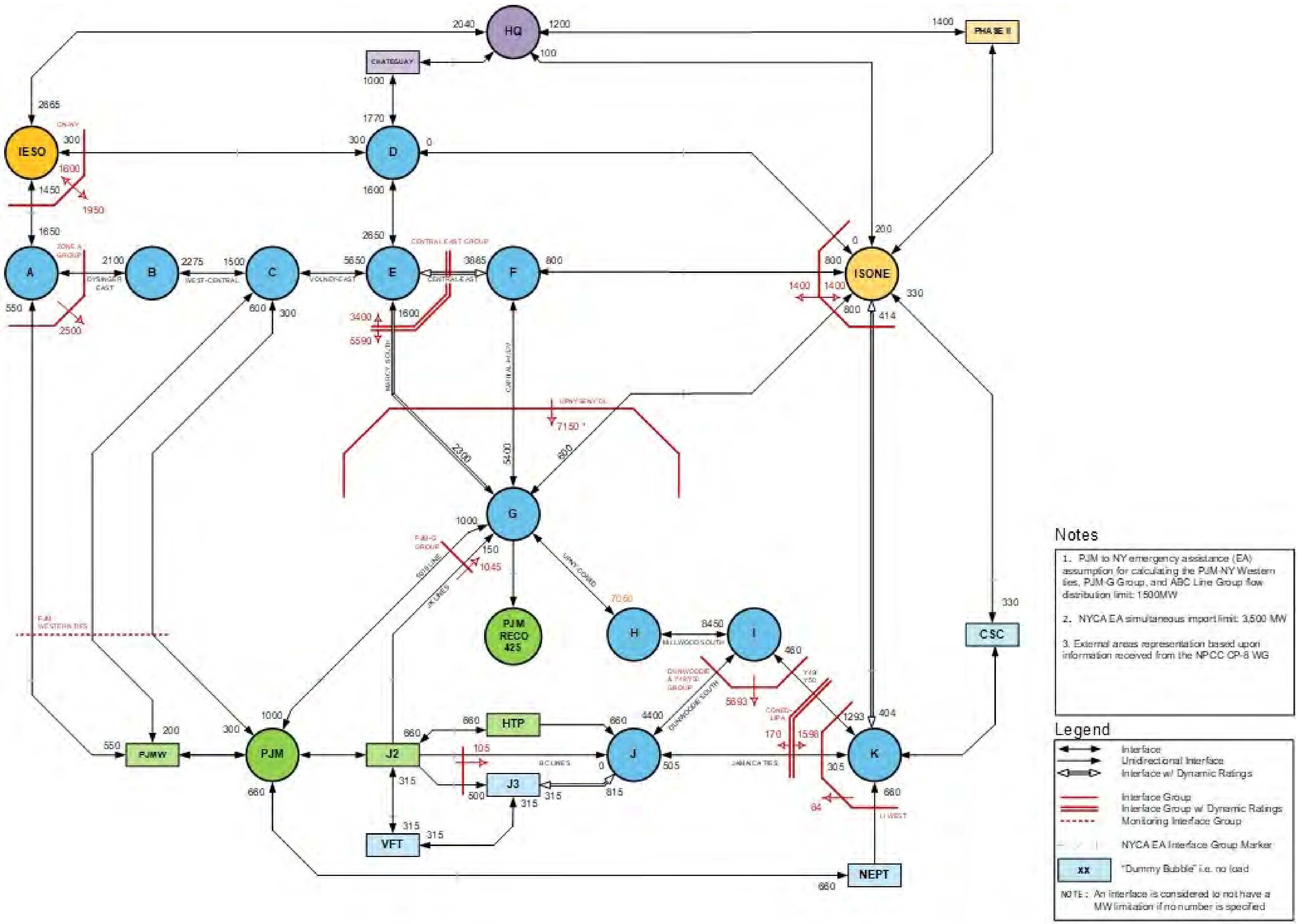
Table A.10 Transmission System Model

Parameter	2023 Model Assumptions	2024 Model Assumptions Recommended	Basis for Recommendation
UPNY-ConEd Interface Limit	Zone G to H transfer limit at 6,675 MW	Zone G to H transfer limit increase to 7,050 MW	Segment B of AC Transmission in service
West-Central NY Limits	Zone A export limit – 2,650 MW Zone A to B limit – 2,200 MW Zone B to C limit – 1,500 MW Zone C to B limit – 2,275 MW	Zone A to B limit reduced to 2,100 MW and Zone A export limit reduced to 2,500 MW	Aligned with updated planning study assumptions for year 2024
Cedars Import Limit	1,770 MW of import Capability to Zone D from Chateauguay	No modeling change from the 2022 assumption	Based on the most recent NYISO studies and processes, such as Operating Study, Operations Engineering Voltage Studies, Comprehensive System Planning Process, and additional analysis including interregional planning initiatives.
IESO/NYISO PARS in Zone D	Restore the transfer limits between IESO and NYCA to the full 300 MW	No modeling change from the 2023 assumption	The outage impacting phase shifters L33/34P is expected to end by Summer 2023
Central East and Central East + Marcy Group Transfer Limit	Central East Dynamic limit table ranging from 2,645 to 2,356 MW. Central East + Marcy Group Dynamic Limit table ranging from 4,260 to 3,845 MW	Central East dynamic limit table ranging from 3,885 to 3,470 MW Central East + Marcy Group dynamic limit table ranging from 5,590 to 4,945 MW	Impact from the construction of Segment B Project, as well as the delay of the construction of Dover PAR (of AC Transmission Project).
UPNYSENY Transfer Limit	Upstate to downstate transfer limit at 5,250 MW; dynamic limit table ranging from 5,350 to 5,250 MW	Upstate to downstate transfer limit increase to 7,150 MW; dynamic limit table removed	Segment B of the AC Transmission Project in service; delay of Dover PAR construction is assessed but no change to the modeled transfer limits[4]
Neptune UDR Import Limit Restoration	Restore the import limit from the Neptune UDR to the full 660 MW	No modeling change from the 2023 assumption	The transformer is expected to return to service during the 2023 capability year

[4] The NYISO tested various scenarios of the UPNYSENY transfer limit and concluded that the transfer limit reduction on UPNYSENY is not expected to impact the IRM study results. Therefore, the UPNYSENY transfer limit is modeled as if the Segment B of AC Transmission project is fully in service.

LIPA Dynamic Ratings	Jamaica Ties import limit at 320 MW. ConEd-LIPA import limit at 1,613 MW. ConEd-LUPA export limit at 135 MW. Y49/Y50 Export limit at 420 MW. LI-West export limit at 49 MW. ConEd-LIPA Dynamic Rating table for Zone K to I and J at 130/0 MW.	Jamaica Ties import limit reduced to 305 MW. ConEd-LIPA import limit reduced to 1,598 MW. ConEd-LIPA export limit increased to 170 MW. Y49/Y50 Export limit increased to 460 MW. LI-West export limit increased to 84 MW. ConEd-LIPA Dynamic Rating table for Zone K to I and J increased to 170/15 MW.	Revised limits based on updated transfer assumptions between LI and NYC, as well as decreases in load in the West of New Bridge area which lower the thermal loading on LI internal transmission facilities.
Cable Forced Outage Rates	All existing Cable EFORs updated for NYC and LI to reflect most recent five-year history	All existing Cable EFORs updated for NYC and LI to reflect most recent five-year history	Based on TO analysis or NYISO analysis where applicable
UDR line Unavailability	Five-year history of forced outages	Five-year history of forced outages	NYISO/TO review

Figure A.10 2024 IRM Topology



* The NYISO tested various scenarios of the UPNYSENY transfer limit and concluded that the transfer limit reduction on UPNYSENY is not expected to impact the IRM study results. Therefore, the UPNYSENY interface limit is modeled as if the Segment B of AC Transmission project is fully in service for purposes of the 2024 IRM study.

Table A.11 shows the interface limits including dynamic limits used in the 2024 IRM study topology VS. the 2023 IRM study.

Table A.11 Interface Limits Updates

	2023		2024		Delta	
Interface	**Forward**	**Reverse**	**Forward**	**Reverse**	**Forward**	**Reverse**
Zone A to B	2, 200 MW	-	2, 100 MW	-	-100 MW	-
Zone A Export Limit	2,650 MW	-	2,500 MW	-	-150	-
Zone B to C	1,500 MW	2,275 MW	1,500 MW	2,275 MW	0	0
Chateguay to Zone D	1,770 MW	1,000 MW	1,770 MW	1,000 MW	0	0
Central East	2,645/2,640/2,585/2,530/2,440/2,365 MW	-	3,885/3,805/3,725/3,640/3,540/3,460 MW	-	1,240/1,165/1,140/ 1,110/1,100/1,095 MW	-
Central East + Marcy Group	4,260/4,260/4,185/4,100/3,970/3,845 MW	-	5,590/5,475/5,360/5,235/5,080/4,945 MW	-	1,330/1,215/1,175/ 1,135/1,110/1,100 MW	-
UPNYSENY	5,250 MW; dynamic limits range from 5350 to 5250		7,150 MW; No dynamic limits		1,900 MW; Removal of dynamic limits	
Zone K to Zones I and J Group	1,613 MW	135/130 /0 MW	1,598 MW	170/170/ 15 MW	-15 MW	35/40/15 MW

The Topology for the 2024 IRM study features the three major changes from the 2023 IRM study.

1. In service of Segment B of AC Transmission Project, but with delay in the construction of the Dover PAR:
    - The Central East voltage collapse limit increases from 2,654 MW to 3,885 MW; dynamic limits are also increased by a similar amount. These limits are calculated by bypassing the series compensation at Knickerbocker and Dover PAR due to the delay of the construction of the Dover PAR.
    - The Central East + Marcy Group limit is increased from 4,260 MW to 5,590 MW due to the improvement of Central East voltage collapse limit; dynamic limits are also increased by a similar amount. These limits are calculated with the bypassing of the series compensation at Knickerbocker and Dover PAR due to the delay of the construction of the Dover PAR.
    - The UPNY-ConEd limit increases from 6,675 MW to 7,050 MW. The delay of the Dover PAR construction has no impact on the increase in transfer limit for UPNY-ConEd interface.

- The UPNYSENY limit increases from 5,250 MW to 7,150 MW, with the removal of dynamic limits. Due to the delay of the construction of Dover PAR, the UPNYSENY transfer limit is expected to be lower than 7,150 MW but a specific reduction was not determined by the NYISO for inclusion in the 2024 IRM study. Various scenarios of the UPNYSENY transfer limit reduction have been tested and it was concluded that the transfer limit reduction on UPNYSENY is not expected to impact the IRM study results. Consequently, the UPNYSENY limit for the IRM study was run at 7,150 MW.

2. Updates to Dysinger East and Zone A Group Limits:
   The Dysinger East and Zone A Group limits were updated as follows
   - Dysinger East limit is reduced from 2,200 MW to 2,100 MW. Zone A group limit is reduced from 2,650 MW to 2,500 MW. Both updates are based on the updated Year 2024 assumptions in the planning study.

3. Updates to Zone K Transfer Limits:
   Based on study conducted by PSEG LI, the updates in the transfer assumptions between NYC and LI and the reduced load in West of New Bridge area result in the changes in various transfer limits around Zone K:

   - Jamaica Ties import limit decreases from 320 MW to 305 MW
   - Coned-LIPA import limit decreases from 1,613 MW to 1,598 MW
   - ConEd-LIPA export limit increases from 135 MW to 170 MW
   - Y49/Y50 export limit increases from 420 MW to 460 MW
   - LI West export limit increases from 49 MW to 84 MW

Additional topology changes were made to the external area models in accordance with information received through the NPCC CP-8 working group.

A.3.5 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 IRM study the limit was 3,500 MW for all LFU bins. For the 2024 IRM study, the EA limit has been updated to vary by LFU bin or load level. Based on a study and recommendation from the NYISO[5] that considered the amount of extra reserves that are available in the external Control Areas above an 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 Control Areas were adjusted such that the total EA from all Control Areas does not exceed the EA limit by LFU Bin.

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 the Area's reserve margin is lower than its requirement and its LOLE is higher than its criterion, pre-emergency demand response can be represented. In other words, the neighboring 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 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.

Modeling of the neighboring Control Areas in the base case in accordance with Policy 5-17 is as follows:

[5] 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".

Table A.12 External Area Representations

Parameter	2023 Study Assumption	2024 Study Assumption	Explanation
Capacity Purchases	Grandfathered amounts: PJM – 1,080 MW HQ – 1,110 MW All contracts model as equivalent contracts	Grandfathered amounts: PJM – 1,013 MW HQ – 1,190 MW All contracts model as equivalent contracts	Grandfathered Rights, ETCNL, and other FERC identified rights.
Capacity Sales	Long term firm sales of 265.9 MW	Long term firm sales of 265.3 MW	These are long term federally monitored 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
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.13 shows the final reserve margins and LOLEs for the Control Areas external to NYCA. The 2024 external area model was updated from 2023 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 6.1% in the 2024 IRM study compared to 7.6% in the 2023 IRM study.

Table A.13 Outside World Reserve Margins

Area	2023 Study Reserve Margin	2024 Study Reserve Margin	2023 Study LOLE (Event-Days/Year)	2024 Study LOLE (Event-Days/Year)
Quebec	54.7%*	49.7%	0.106	0.119
Ontario	14.6%	5.1%	0.122	0.111
PJM	14.4%	14.7%	0.185	0.404
New England	9.7%	4.4%	0.109	0.114

*This is the summer margin.

A.3.6 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.15 were provided by the NYISO based on operator experience. Table A.14 lists the assumptions modeled.

The values in Table A.15 (top of next page) are based on a NYISO forecast that incorporates 2023 (summer) operating results. This forecast is applied against a 2024 peak load forecast of 31,765.6 MW. 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.14 Assumptions for Emergency Operating Procedures

Parameter	2023 Study Assumption	2024 Study Assumption	Explanation
Special Case Resources*	July 2022–1224.8 MW based on registrations and modeled as 855.9 MW of effective capacity. Monthly variation based on historical experience.	July 2023–1,281 MW based on registrations and modeled as 896.5 MW of effective capacity. Monthly variation based on historical experience.	SCRs sold for the program discounted to historic availability. Summer values calculated from July 2023 registrations. Performance calculation updated per ICS presentations on SCR performance.
Other EOPs	350 MW of 10-min Operating Reserve maintained at Load Shedding. 860.0 MW of non-SCR/non-EDRP resources. 1,615 MW from reducing operating reserves	400 MW of 10-min Operation Reserve maintained at Load Shedding. 929.8 MW of non-SCR/non-EDRP resources. 1,565 MW from reducing operating reserves	Based on white paper recommendation approved by EC Based on TO information, measured data, and NYISO forecasts
EOP Structure	10 EOP Steps Modeled	10 EOP Steps Modeled	Based on ICS recommendation

- The number of SCR calls is limited to 5 per month when calculating LOLE.

Table A.15 Emergency Operating Procedures Values

Step	Procedure	2023 IRM MW Value	2024 IRM MW Value
1	Special Case Resources – Load, Gen	1,224 MW Enrolled/ 860 MW Modeled	1,281 MW Enrolled/ 896.5 MW Modeled
2	5% manual voltage Reduction	85.43 MW	113.11 MW
3	Thirty-minute reserve to zero	655 MW	655 MW
4	Voluntary industrial curtailment	240.05 MW	267.17 MW
5	General Public Appeals	80 MW	74 MW
6	5% remote voltage reduction	452.92 MW	475.56 MW
7	Emergency Purchases	Varies	Varies
8	Ten-minute reserves to zero	960 MW (350 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.3.7 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 Zone to another for meeting load requirements. Previous studies have identified transmission constraints into certain Zones that could impact the LOLE of these Zones, as well as the statewide LOLE. To minimize these potential LOLE impacts, these Zones require a minimum portion of their NYCA ICAP requirement, *i.e.,* locational ICAP, which shall be electrically located within the 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 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.3.8 Special Case Resources

Special Case Resources (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.16:

Table A.16 SCR Performance

For 2024 IRM - Final SCR Model Values							
Program	Super Zone	Superzone Performance Factor	ICS Adjustment Factors		Effective Performance Factor	SCR ICAP MW based on July 2023	Final Model Values MW
			ACL to CBL Factor	Fatigue Factor			
SCR	A-F	87.3%	92.9%	100%	81.1%	719	583
SCR	G-I	77.4%	84.2%	100%	65.1%	84	55
SCR	J	70.6%	74.5%	100%	52.6%	442	233
SCR	K	69.8%	76.2%	100%	53.2%	35	19
Total						**1281.0**	**890**
							69.5%

Table A.16 note 1: These values represent no growth from July 2023 ICAP based enrollments. Table A.16 note 2: The Performance Factor is based on the average coincident load (ACL) methodology. Table A.16 note 3: The SCR Adjustment factor (3) captures two different performance derates; 1) Calculated Translation Factor (TF) between ACL and customer baseline load (CBL) values, and the Fatigue Factor (FF=1.00)

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. For the month of July 2023, the registered value is 1,281.0 MW. The effective value of 890.0 MW is used in the model.

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 either confirms that it is the right value as is or institutes an update. The results of this data scrub are shown in the table below for the preliminary base case. The results of this data scrub are shown in Table A.17 for the preliminary base case.

Table A.17 GE MARS Data Scrub

Item	Description	Disposition	Data Change	Parametric Effect
1	25 units had changes in capacity that exceeded 10 MW; 13 units identified with large EFORd changes	These changes were part of larger annual update, and confirmed to be correct	N	N/A
2	2 interface limits were found to be inconsistent between data base and Assumptions Matrix	Data base was confirmed to be correct; diagram and limits in the Assumptions Matrix were corrected	N	N/A
3	Dynamic and static limits updated for 2 interfaces	Verified update to the 2024 model, i.e., AC Transmission project and delay in Dover PAR	Y	+0.02
4	Updates to EA modelling and changes to RECO contract	New EA model verified in 2024 model. Changes to RECO contract were made to accommodate the new modelling	N	N/A
			Total	+0.02

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.18 NYISO Data Scrub

Item	Description	Disposition	Data Change	Parametric Effect
1	The EFORd values in the data base and Master Spreadsheet were incorrect	Values were updated in the MIF and Master Spreadsheet to align with the updated GADs transition rates	Y	+0.04
2	Capacity values for a number of units were not aligned with the Gold Book values	A total of 6 MW of capacity was added as correction	Y	-0.01
			Total	+0.03

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.19 Transmission Owner Data Scrub

Item	Description	Disposition	Data Change	Parametric Effect
1	2 interface limits were found to be inconsistent between data base and Assumptions Matrix	Data base was confirmed to be correct; diagram and limits in the Assumptions Matrix were corrected	N	N/A
2	Transmission limits between ISONE and Zone F and G were calculated incorrectly	Values were corrected	Y	+0.00
			Total	+0.00

Appendix B

Details of Study Results

B. Details for Study Results – Appendix B

B.1 Sensitivity Results

Table B.1 summarizes the 2024-2025 Capability Year IRM requirements under a range of assumption changes from those used for the base case. The base case utilized the computer simulation, reliability model, and assumptions described in Appendix A. The sensitivity cases determined the extent of how the base case required IRM would change for assumption modifications, either one at a time, or in combination. The methodology used to conduct the sensitivity cases was to start with the preliminary base case 23.0% IRM results then add or remove capacity from all zones in NYCA until the NYCA LOLE approached criterion. The values in Table B.1 on top of next page are the preliminary base case sensitivity results adjusted to the 23.1% final base case.

In addition to showing the IRM requirements for various sensitivity cases, Table B.1 shows the Loss of Load Hours (LOLH) and Expected Unserved Energy (EUE) reliability metrics for each case[6]. These two metrics, along with the LOLE metric, are important measures of reliability risk in that together, they describe the frequency, duration, and magnitude of loss of load events. The reliability risk measures provided by these two metrics, in addition to IRM impacts, provide Executive Committee members with different aspects of system risk for selecting the Final IRM. The data used to calculate LOLH and EUE are collected from GE-MARS output.

Table B.1 shows the IRM requirements for the various sensitivity cases. Note, Case 0 was the original Preliminary Base Case. All of the sensitivity cases are relative to that. Case 6a with the reduced emergency assistance (EA) from neighboring systems was then selected for the new base case and the resulting 23.1% IRM. Because of the lengthy computer run time and personnel needed to perform a full Tan 45 analysis in IRM studies, this method was applied for only select cases as noted in the table. While the parametric analyses are broadly indicative of magnitude and direction of the IRM impacts, it should be recognized that some accuracy is sacrificed when a Tan 45 analysis is not utilized.

These two metrics, along with the LOLE metric, are important measures of reliability risk in that together, they describe the frequency, duration, and magnitude of loss of

[6] **LOLH: Loss of Load Hours**: The expected number of hours during loss of load events each year when the system's hourly demand is projected to exceed the generating capacity.
EUE: Expected Unserved Energy: The expected amount of energy (MWh) during loss of load events that cannot be served each year**.**

load events. The reliability risk measures provided by these two metrics, in addition to IRM impacts, provide Executive Committee members with different aspects of system risk for selecting the Final IRM. The data used to calculate LOLH and EUE are collected from GE-MARS output.

Sensitivity Cases 1 through 5 in Table B.1 are annually performed and illustrate how the IRM would be impacted if certain major IRM study parameters were not represented in the IRM base case. Case 4, No Wind Capacity, was split into two cases so that the impact of land-based and off-shore wind generation could be evaluated separately.

Case 6a examines the impact of reduced EA from neighboring systems based on the recommendations from the analysis in the EOP Whitepaper. Case 6b further reduced the winter limits to zero. As mentioned previously, Case 6a was subsequently selected as the new base case going forward. The various versions of Case 7 look at reducing winter capacity due to potential gas constraints as built on top of Case 6. Finally, Case 8 looked at the impact of the delay on the installation of the Dover PAR. While some limits were affected the overall impact on the IRM was negligible.

Table B.1 Sensitivity Case Results

Table B-1 2024/2025 IRM Sensitivity Cases

Case	Description	IRM (%)	NYC (%)	LI (%)	IRM (%) Change from Base	LOLH (hrs/yr)	EUE (MWh/yr)
0	2024 IRM Final Base Case	23.1	72.7	103.2	-	0.33711	180.827
	These are the Base Case technical results derived from knee of the IRM-LCR curve						
1	NYCA Isolated	29.2	77.2	116.2	+6.2	0.30757	195.821
	Track Total NYCA Emergency Assistance – NYCA system is isolated and receives no emergency assistance from neighboring control areas (New England, Ontario, Quebec, and PJM). UDRs are allowed (Prior to adoption of new EA limits)						
2	No Internal NYCA transmission constraints	21.1	71.3	107.9	-2.0	0.34624	272.719
	Track level of NYCA congestion with respect to the IRM model – internal transmission constraints are eliminated and the impact of transmission constraints on statewide IRM requirements is measured						
3	No Load Forecast Uncertainty	18.0	69.1	104.7	-5.1	0.25842	59.361
	Shows sensitivity of IRM to load uncertainty, if the forecast peak loads for NYCA have a 100% probability of occurring						
4a	No Wind Capacity – Land-Based Wind Only	17.4	72.7	109.9	-5.7	0.34157	185.615
	Shows wind impact for the land-based wind units and can be used to understand EFORd sensitivity (A – F Shifting)						
4b	No Wind Capacity – All Wind Units	16.3	73.4	108.4	-6.8	0.3442	195.546
	Shows wind impact for both land-based and off-shore wind units and can be used to understand EFORd sensitivity						
5	No SCR Capacity	20.0	69.5	109.9	-3.1	0.31885	161.200
	Shows sensitivity of IRM to SCR program						

Table B-1 2024/2025 IRM Sensitivity Cases (Continued)

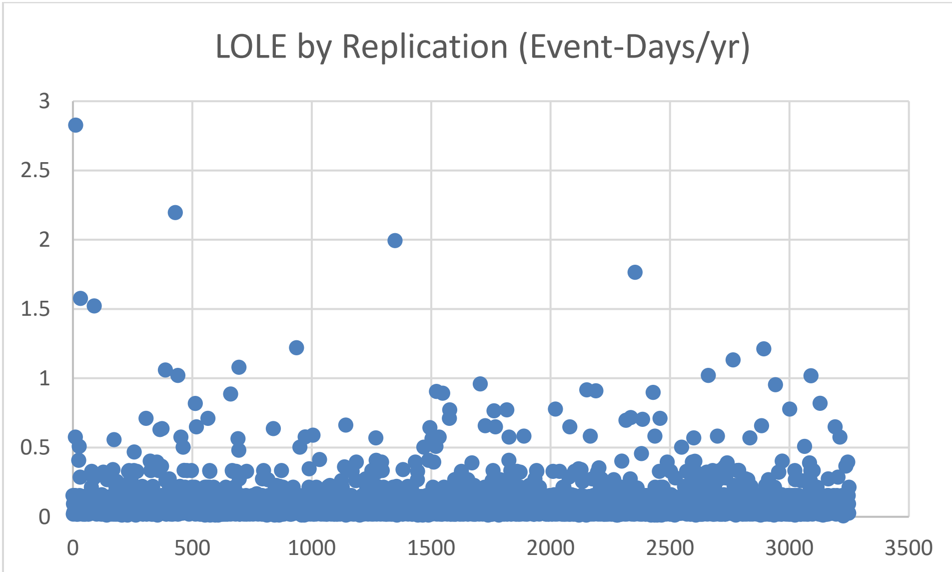
Case	Description	IRM (%)	NYC (%)	LI (%)	IRM (%) Change from Base	LOLH (hrs/yr)	EUE (MWh/yr)
6a	EOP (Emergency Operating Procedures) Whitepaper Recommendation	23.0	72.4	109.5	-0.1	0.36814	227.886
	Shows impact of modifying EA from neighboring areas modeled during the EOP steps in accordance with the EOP Whitepaper recommendation (Tan 45)						
6b	EOP Whitepaper Recommendation plus Winter EA Zeroed Out	23.0	72.4	109.5	- (Based off 6a)	0.36823	227.895
	Built upon Sensitivity 6a, shows impact of reducing EA from neighboring areas to 0 in winter						
7a-1	Winter Constraints plus S06a (3,500 MW)	23.0	72.4	109.5	- (Based off 6a)	0.36814	227.886
	Shows impact to reliability when winter capacity is reduced due to gas constraints and can be used to understand tightening winter conditions. Built off of case 6a.						
7a-2	Winter Constraints plus S06a (7,000 MW)	23.2	72.4	109.6	+0.1 (Based off 6a)	0.36557	224.831
	Shows impact to reliability when winter capacity is reduced due to gas constraints and can be used to understand tightening winter conditions. Built off of case 6a.						
7b-1	Winter Constraints plus S06b (3,500 MW)	23.0	72.4	109.5	- (Based off 6b)	0.36824	227.898
	Shows impact to reliability when winter capacity is reduced due to gas constraints and can be used to understand tightening winter conditions. Built off of case 6b.						
7b-2	Winter Constraints plus S06b (7,000 MW)	23.8	72.9	110.3	+0.8 (Based off 6b)	0.33256	191.207
	Shows impact to reliability when winter capacity is reduced due to gas constraints and can be used to understand tightening winter conditions. Built off of case 6b.						

B.2 Review of LOLE Results and Additional Reliability Metrics

B.2.1 Review of LOLE Results

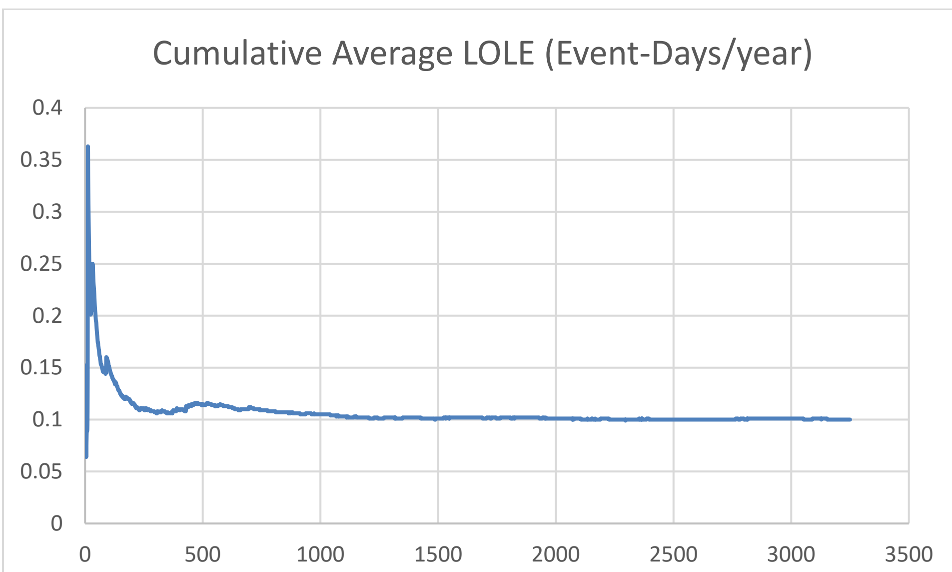
By design, the 2024 IRM study final base case (FBC) had an average LOLE of 0.100 events/year. However, that doesn't tell the whole story. The Monte Carlo logic simulated the system for 3,250 replication years and the annual values ranged from a minimum of 0.006 events/year to a maximum of 2.826 events/year. The figure B1 below shows the value of the LOLE for each of the replication years.

Figure B1 Value of LOLE by Replication Year



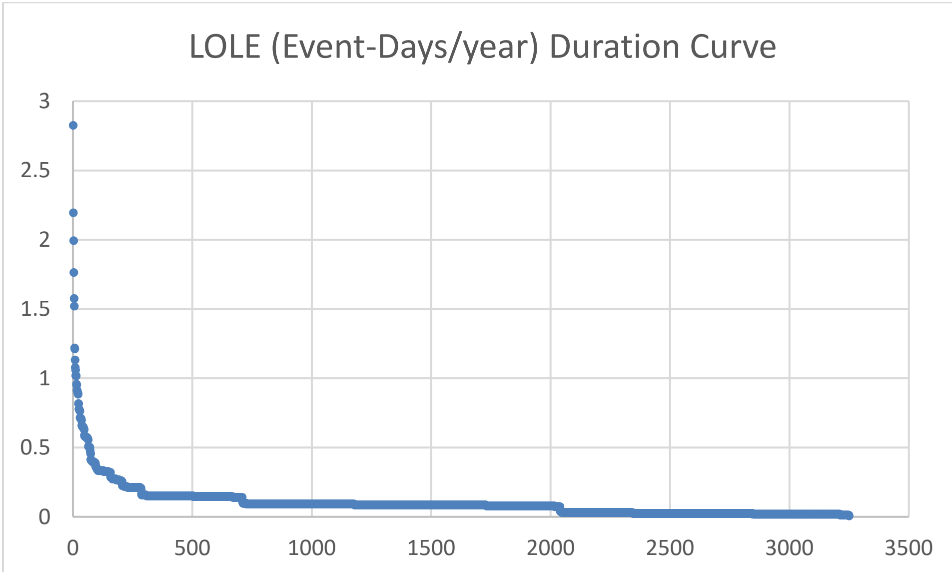
The next curve, figure B2, shows the cumulative average over the course of the replications. After some initial fluctuations the value can be seen to settle out after about 1,500 replications and is fairly constant after 3,250 replications.

Figure B2 LOLE Cumulative Average Over Replication Years



The figure B3 below shows a duration curve of the 3,250 values. While the average value is 0.100 there are hundreds of replications where the value was much higher.

Figure B3 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 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 4 hours, events exceeding 9 hours occurred.

Table B2 Additional Metrics

3,250 Replications	Minimum	Maximum	Average
LOLE (Event-Days/year)	0.006	2.826	0.100
HLOLE Event (Hours/year)	0.031	8.460	0.378
EUE (MWh/Year)	5.630	2471.110	224.976
Duration (Hours/Event)	1.229	10.333	4.525
Magnitude (MW/Event)	118.730	1566.906	675.934

The table B3 below shows the results for the first 10 replications. The Duration and Magnitude were estimated from each iteration. The average of the ten duration values was 4.238 hours/event. If the value is calculated from the average LOLE and HLOLE over the ten iterations the result is 3.673 = .350/.095. The value in the table B2 above was calculated as the average of the 3,250 duration values.

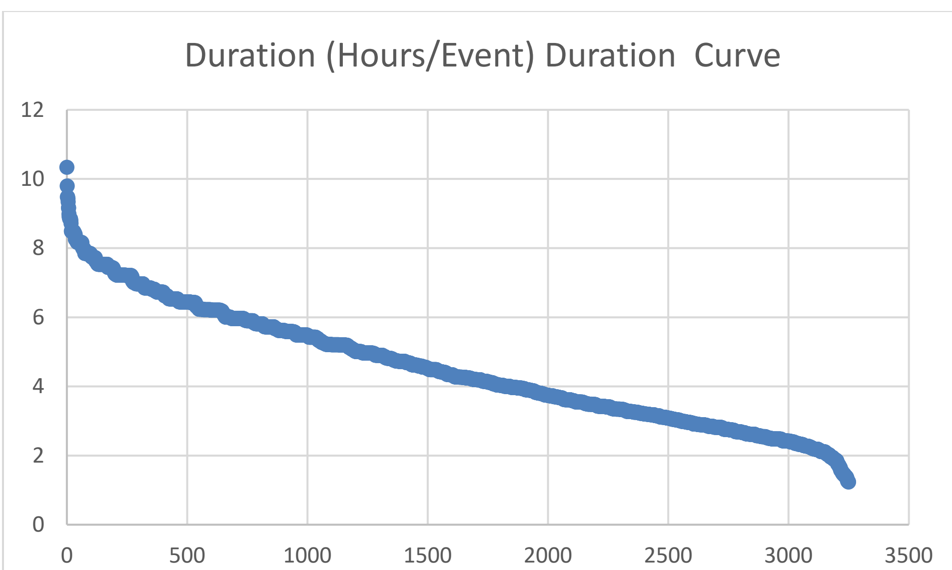
Table B3 Results of the First Ten Replications

ITERATION	LOLE (Event-Days/year)	HLOLE (Event-Hours/year)	EUE (MWh/year)	Duration =HLOLE/LOLE (Hours/Event)	Magnitude =EUE/HLOLE (MW/Event)
1	0.152	0.374	284.19	2.461	759.866
2	0.019	0.149	87.91	7.842	590.000
3	0.092	0.412	473.76	4.478	1149.903
4	0.031	0.155	115.33	5.000	744.065
5	0.025	0.118	77.76	4.720	658.983
6	0.152	0.514	430.13	3.382	836.829
7	0.152	0.66	409.24	4.342	620.061
8	0.092	0.362	163.46	3.935	451.547
9	0.085	0.245	190.39	2.882	777.102
10	0.152	0.508	310.03	3.342	610.295

Average	0.095	0.350	254.220	4.238	719.865
Calculated from Average				3.673	726.966

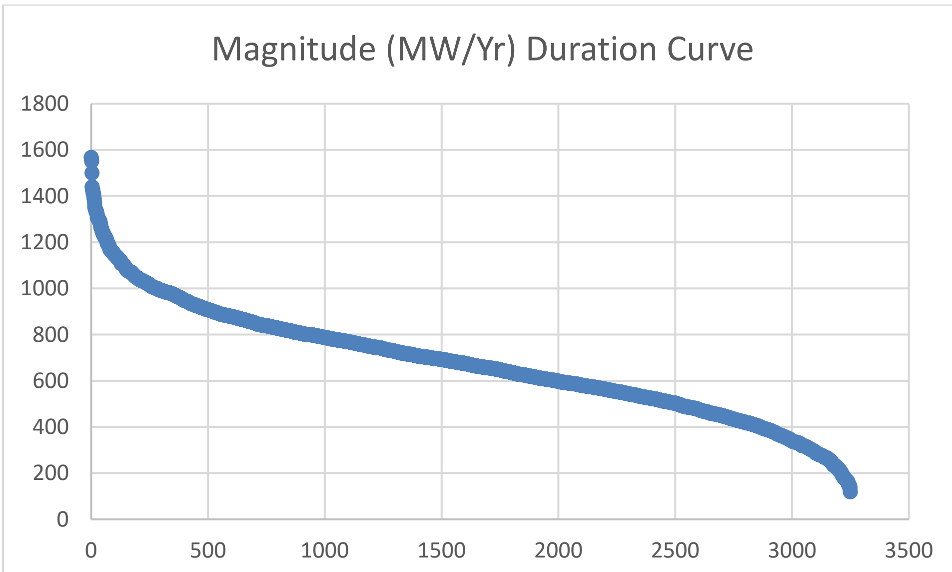
The average duration for the replication years ranges from 1.2 hours to 10.3 hours with an average value of 4.5 hours/event. These are averages over the replication year so they don't capture the full potential range, but they do give a better estimate. As graph below (Figure B4) shows, a 4-hour storage would be insufficient to cover the outage in over 50% of the cases.

Figure B4 Hours/Event Duration Curve



In a similar manner the expected Magnitude of the outage was determined for each replication (Figure B5). Although the average was 676 MW over the 3,250 values the maximum exceeded 1,500 MW.

Figure B5 MW/Yr Duration Curve



B.2.3 Conclusions

Although the new calculated and derived 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 Frequency of 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 2024 EOP capacity values are based on recent actual data and NYISO forecasts. SCR calls were limited to 5 per month. Table B.4 below presents the expected EOP frequencies for the 2024-25 Capability Year assuming the 23.1% base case IRM with ELR modeling. Table B.5 presents SCR calls by months.

Table B.4 Implementation of EOP steps

Step	EOP	Expected Implementation (Days/Year)
1	Require SCRs (Load and Generation)	8.1
2	5% manual voltage reduction	6.1
3	30-minute reserve to zero	5.9
4	Voluntary load curtailment	2.8
5	Public appeals	2.2
6	5% remote controlled voltage reduction	2.0
7	Emergency purchases	1.4
8	10-minute reserve to 400 MW	0.2
9	Customer disconnections	0.1

Note 1: The expected implementation days per year reported in each EOP step are the expected number of days that GE-MARS calls for that EOP step. If an EOP step has a limitation on the number of days that it can provide load relief, such as the 5 days per month limit for SCRs, it will provide no load relief after the 5th day.

Table B.5 SCR Calls Per Month

SCR Calls Per Month	
Month	Days/Month
JAN	0.0
FEB	0.0
MAR	0.0
APR	0.0
MAY	0.0
JUN	0.4
JUL	2.6
AUG	3.5
SEP	1.6
OCT	0.0
NOV	0.0
DEC	0.0

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. 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. Prior studies have identified the amounts of capacity that may be negatively impacted by new and developing regulations. Most recently, New York has enacted the Climate Leadership and Community Protection Act (CLCPA) and the Accelerated Renewable Energy Growth and Community Benefit Act 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. 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 will be 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 requires 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 (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 have deactivated or limited their operation. An additional 590 MW of affected generation are expected to become unavailable beginning May 1, 2025, all of which are located in New York City. With the additional generation unavailable, the bulk power transmission system will not be able to securely and reliably serve the forecasted demand

[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)

in New York City (Load Zone J). Specifically, the New York City zone is deficient by as much as 446 MW for a duration of nine hours on the peak day during expected weather conditions when accounting for forecasted economic growth and policy-driven increases in demand.

The NYISO solicited solutions to address this need in August 2023 with responses provided to the NYISO in early October 2023. On November 20, 2023, after evaluation of the proposals submitted in response to its solicitation, the NYISO determined that no proposals could be installed by May 2025, or were sufficient to address the identified deficiency of up to 446 MW. As a result, consistent with provisions of the Peaker Rule that permit the NYISO to temporarily retain affected generation as a last resort if no other solutions are viable or sufficient to timely address an identified reliability need, the NYISO identified generators on the Gowanus 2 & 3 and Narrows 1 & 2 barges as the temporary solution for the reliability need in New York City. Those generators will remain available for two years beyond the May 1, 2025 deactivation date established by the Peaker Rule.

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 Clear Water Act Section 316b rule providing standards for the design and operation of power plant cooling systems. This rule is being implemented by the DEC, which has finalized a policy 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.

Plant	Status as of September 2023
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
East River	BTA in place
Fitzpatrick	BTA studies being evaluated
Ginna	BTA studies being evaluated
Greenidge	BTA in place
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, SAPA extended
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 applies to about 3,000 MW of generation in New York City. Affected generators have filed compliance plans with NYC agencies to switch to compliant fuels. The affected generators are developing new fuel storage and handling equipment necessary to convert their facilities to comply with the law.

C.4 Regional Greenhouse Gas Initiative (RGGI)

RGGI is a multi-state carbon dioxide emissions cap-and-trade initiative that requires affected generators to procure emissions allowances authorizing them to emit carbon dioxide. The RGGI states have agreed to a 30% cap reduction between 2020 and 2030, essentially ratcheting down the availability of allowances to generators that emit CO_2. The DEC extended RGGI applicability in New York to certain generators of 15 MW (nameplate) or larger in 2021. The current emission allowance caps and design elements are not likely to trigger reliability concerns as the 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 started a third program review which is anticipated to conclude in 2023. The states are reviewing cap trajectories with increased stringency beginning in 2026, ultimately declining to zero by 2035 or 2040, and have indicated a preference for moving to annual compliance periods from the current three-year design. 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.

C.5 Distributed Generator NOx Emission Limits

The DEC has adopted Part 222, a rule to limit the NOx 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 NOx emissions less than 25 tons of NOx 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 must either obtain a registration or permit by March 15, 2021 and must notify the DEC whether the generator will operate as an economic dispatch source subject to the provisions of Part 222.

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

The CSAPR limits emission of SO_2 and NO_X from fossil fuel fired EGUs >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. NY ozone season NO_X emissions are highly sensitive to the continued operation of the NY nuclear generation fleet.

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 3,550 tons in 2020, 3,997 tons in 2021, 3,506 tons in 2022 and 3,344 tons in 2023. The EPA issued the final Good Neighbor Plan for the 2015 Ozone NAAQS on March 15, 2023 expanding the Group 3 region from 12 to 22 states. The rule became effective August 4, 2023, mid-way through the ozone season. In subsequent actions EPA addressed rulings remanding prior state implementation plan (SIP) disapprovals barring enforcement in some states. Currently, the new limits cannot be enforced in 12 of the 22 Group 3 states, representing 70% of the new lower program cap. Under the new rule, NY's ozone season NO_X budget in 2023-2025 *increased* to 3,912 tons. NY may exceed the trading limit in which case higher emitting resources will need to surrender allowances at a rate of 3:1 for their excess emissions.

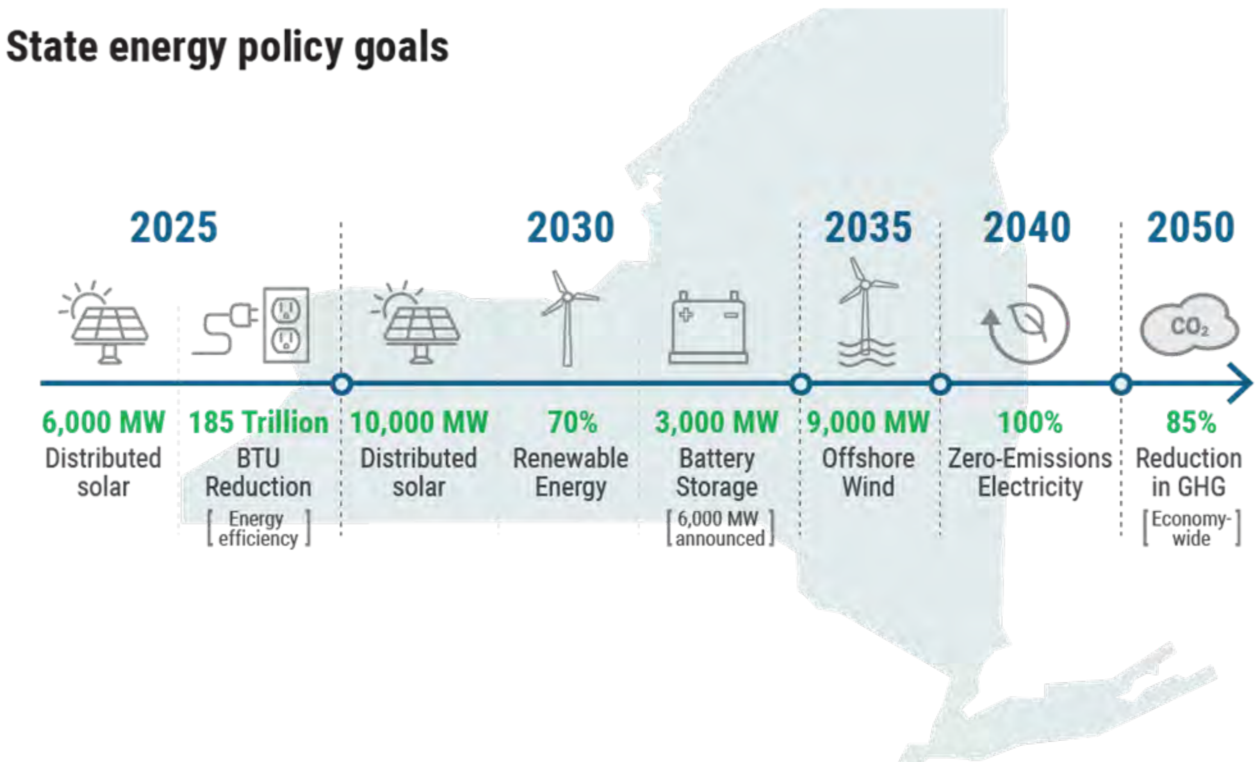
C.7 New York Power Authority Small Gas Turbine Phase Out

Provisions included in New York State's *2023-24 Enacted State Budget* broadened NYPA's authority to develop renewable energy and advanced NYPA's commitment to phase-out their small natural gas power plants.[8] NYPA is 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 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.

[8] See 2023 Laws of New York, Ch. 56, Part QQ, § 5.

C.8 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 eligible renewable resources and other clean energy resources. During this transition, the NPCC and NYSRC resource adequacy rules will require the New York Control Area to maintain resource adequacy for the New York bulk electric system. In addition, the GHG emission reduction requirements necessitate significant electrification of the building and transportation sectors to reduce economy-wide emissions. 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 below. The figure describes the timing and requirements of the major combined clean energy and efficiency policies in New York State.



C.9 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. NYSERDA had executed contracts with the winners of two OREC solicitations for a procurement of four OSW projects totaling nearly 4,300 MW. However, in October 2023, the PSC denied petitions from these OSW projects seeking, among other things, inflation adjustments to their existing OREC contracts. NYSERDA announced awards to the 2022 OREC solicitation on October 24, 2023. NYSERDA selected 4,032 MW across three projects, bringing the total awarded/contracted OSW capacity in the state to nearly 8,400 MW.

C.10 Comprehensive Energy Efficiency Initiative

The PSC has approved an order containing utility budgets and targets to accelerate energy efficiency savings in New York State through 2025. A portion of the 185 TBtu energy savings target established by the CLCPA will come from directed utility programs to support heat pump adoption, as well as from increased deployment of more conventional utility energy efficiency programs.

C.11 Storage Deployment Target

The CLCPA requires 3,000 MW of energy storage capacity to be developed by 2030. This target builds on top of the goal to deploy 1,500 MW energy storage capacity by 2025 outlined in NYSERDA's Energy Storage Roadmap. In early 2022, a doubling of the storage target to 6,000 MW in 2030 was announced and a 6 GW Storage Roadmap was filed for consideration by the PSC. The New York State Department of Public Service (DPS) reported that 1,301 MW in energy storage capacity was deployed, awarded, or contracted as of October 1, 2022.

C.12 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. Achievement 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.

C.13 Clean Energy Standard (CES)

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 2030 Renewable Energy Standard from 50% to 70% 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 and Clean Path New York, which were approved on April 14, 2022, have the potential to add approximately 2,500 MW of controllable HVDC connections into New York City.

C.14 Economy-wide Greenhouse Gas Emissions Limits and New York Cap-and-Invest

The CLCPA also implements a new approach to accounting for climate impacts of emissions of various GHGs and setting numerical economy wide GHG limits. The inventory and methodology 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 CLCPA created a Climate Action Council (CAC) to develop and approve the Final Scoping Plan by the end of 2022. The CAC held numerous meetings to organize the planning process and convened advisory panels focused on various sectors of the economy (such as power generation, transportation, and energy efficiency and buildings) to solicit input and perform detailed evaluations. Starting in 2023, the Final Scoping Plan's recommendations become the platform for state planning and regulatory processes.

The DEC is required under the CLCPA to complete additional regulations to enforce the economy wide GHG limits by 2024. Principle among these regulatory initiatives, the DEC and NYSERDA are developing regulations to implement an economy-wide cap-and-invest program to be finalized in 2024 with potential implementation beginning as soon as 2025. The suite of regulatory programs stemming from the Scoping Plan recommendations will ultimately impact the supply-demand balance in the electric sector.

C.15 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 environmental justice impacts 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. 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 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 greenhouse gas 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 that 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. All three projects have begun the DEC process to appeal the denials.

In December 2022, the DEC finalized 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. Recently, the DEC released a draft policy DEP 23-1 that would implement the environmental justice and disproportionate burden aspects of the CLCPA within many environmental permits. For facilities in or likely to impact disadvantaged communities (DACs), a Disproportionate Burden Report as well as meaningful engagement would also be required under the draft policy.

C.16 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. On October 15, 2020, the PSC designated the Northern New York transmission projects as priority transmission projects to be carried out by NYPA. The DPS-led working group filed an Initial Power Grid Study report at the PSC on November 2, 2020. The report addresses local transmission system needs, proposals for planning transparency, 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. The utilities continue working along with the NYISO within the Coordinated Grid Planning Process to identify local transmission and distribution upgrades, coordinate on grid expansion planning and cost sharing.

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. ORES has approved over 2,200 MW of new renewable energy resource capacity as of October 2023. 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 recently advanced a 12 MW solar facility at a former mine site in its first request for proposals.

C.17 Study Impacts and Insights

To inform policymakers, market participants, and the public, the NYISO has completed a series of studies examining the impact of these various policies on the future supply mix. The NYISO's inaugural *2021-2040 System and Resource Outlook* policy scenarios[9] 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 in the potential supply demand balance to address fundamental issues of load and renewable generation misalignment across seasons. The studies also imply increasing ramping demands placed on resources primarily to respond to the increased intermittent output of renewable generation and increased variability of electrified heating loads.

As outlined in the NYISO's recent Comprehensive Reliability Plan, achieving an emission-free grid will require DEFRs to be developed and deployed throughout New York. As resources shift from fossil generators to zero emission resources, essential grid services, such as operating reserves, ramping, regulation, voltage support, and black start, must be available to provide New Yorkers with reliable and predictable electric system that consumers require. DEFRs will be required to provide both energy and capacity over long durations, as well as the reliability attributes of retiring synchronous generation. The

[9] *See* System and Resource Outlook, A Report from the New York Independent System Operator, available at https://www.nyiso.com/documents/20142/33395392/2021-2040-Outlook-Data-Catalog.pdf/9449f533-28f8-0435-851e-cf798411a2eb

attributes do not need to be encapsulated in a singular technology, but in aggregate the system needs a sufficient collection of these services to be reliable.

DEFRs that provide sustained on-demand power and system stability will be essential to meeting policy objectives while maintaining a reliable electric grid. However, while essential to the grid of the future, such DEFR technologies are not commercially viable today. DEFRs will require committed public and private investment in research and development efforts to identify the most efficient and cost-effective technologies with a view towards the development and eventual adoption of commercially viable resources. The development and construction lead times necessary for these technologies may extend beyond policy target dates.

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 units Dependable Maximum Net Capability (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 historical values (since 2000) for NYCA capacity parameters 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	15.5	18.0		80.0	107.0	
2001	17.1	18.0		80.0	98.0	
2002	18.0	18.0		80.0	93.0	
2003	17.5	18.0		80.0	95.0	
2004	17.1	18.0	11.90	80.0	99.0	
2005	17.6	18.0	12.00	80.0	99.0	
2006	18.0	18.0	11.59	80.0	99.0	
2007	16.0	16.5	11.30	80.0	99.0	
2008	15.0	15.0	8.35	80.0	94.0	
2009	16.2	16.5	7.17	80.0	97.5	
2010	17.9	18.0	6.12	80.0	104.5	
2011	15.5	15.5	6.03	81.0	101.5	
2012	16.1	16.0	5.35	83.0	99.0	
2013	17.1	17.0	6.58	86.0	105.0	
2014	17.0	17.0	6.38	85.0	107.0	88.0
2015	17.3	17.0	7.01	83.5	103.5	90.5
2016	17.4	17.5	6.21	80.5	102.5	90.0
2017	18.1	18.0	7.04	81.5	103.5	91.5
2018	18.2	18.2	8.08	80.5	103.5	94.5
2019	16.8	17.0	6.72	82.8	104.1	92.3
2020	18.9	18.9	9.03	86.6	103.4	90.0
2021	20.7	20.7	10.11	80.3	102.9	87.6
2022	19.6	19.6	7.9	81.2	99.5%	89.2
2023	19.9	20	7.8	81.7	105.2%	85.4

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, Localities and Transmission Districts. This information has been compiled and posted since 2006.

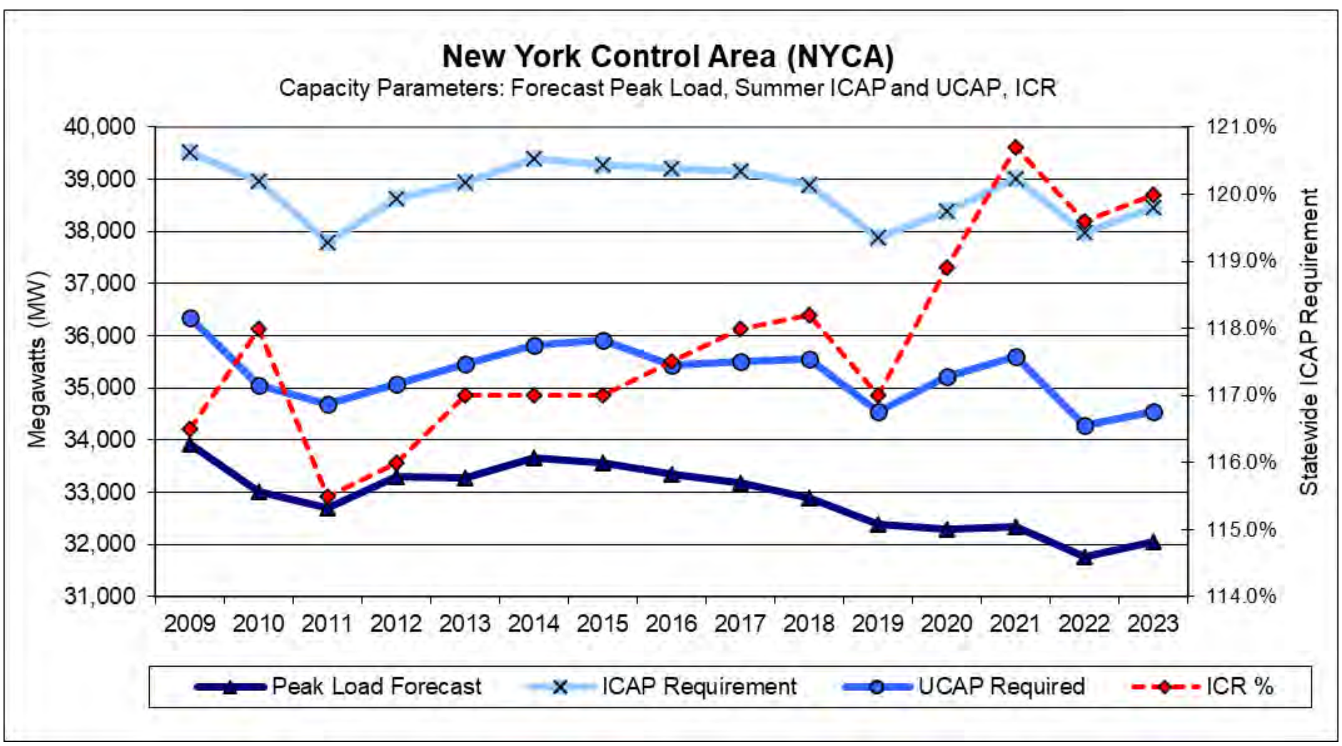
Locational ICAP/UCAP calculations are produced for New York City, Long Island, G-J Locality and the entire NYCA. Exhibits D.1.1 through D.1.4 summarizes the translation of ICAP requirements to UCAP requirements for these areas. The charts and tables included in these exhibits utilize data from the summer capability periods for the most recent 15 years beginning in 2009.

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 NYCA ICAP to UCAP Translation

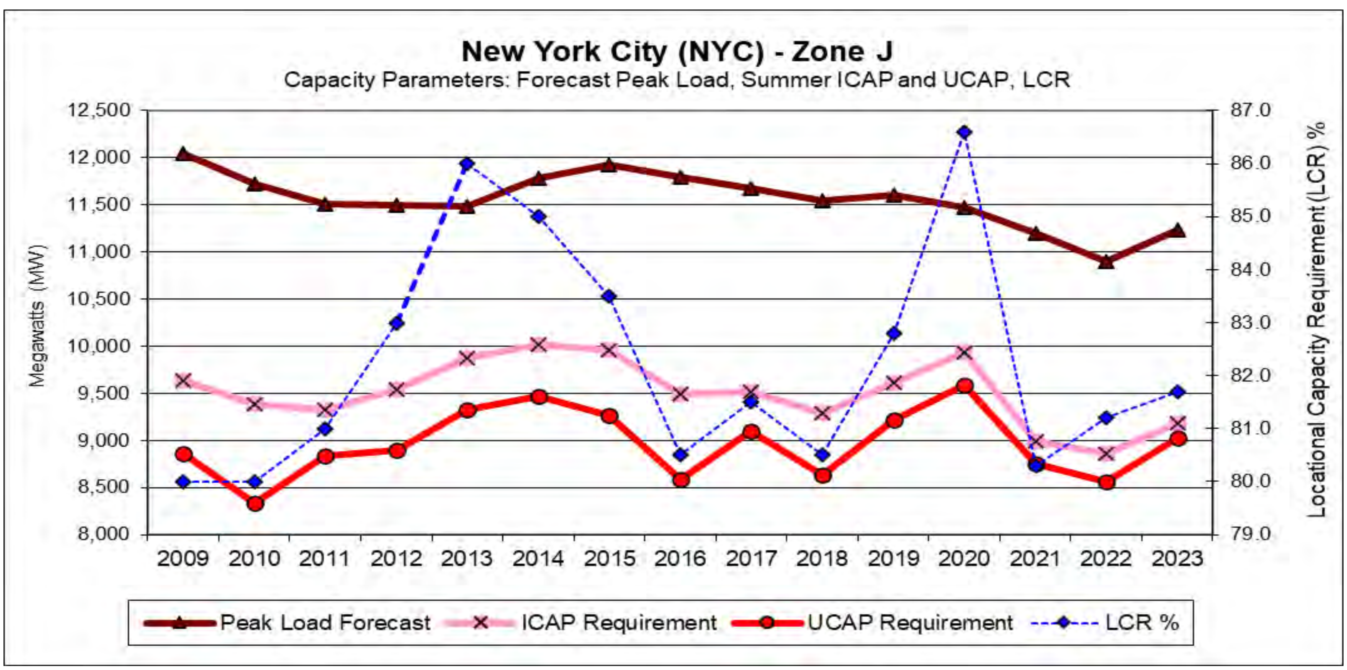
Year	Forecast Peak Load (MW)	Installed Capacity Requirement (%)	Derate Factor	ICAP Requirement (MW)	UCAP Requirement (MW)	Effective UCAP (%)
2009	33,930	116.5	0.0801	39,529	36,362	107.2
2010	33,025	118.0	0.1007	38,970	35,045	106.1
2011	32,712	115.5	0.0820	37,783	34,684	106.0
2012	33,295	116.0	0.0918	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%



D.1.2 New York City ICAP to UCAP Translation

Table D.3 New York City ICAP to UCAP Translation

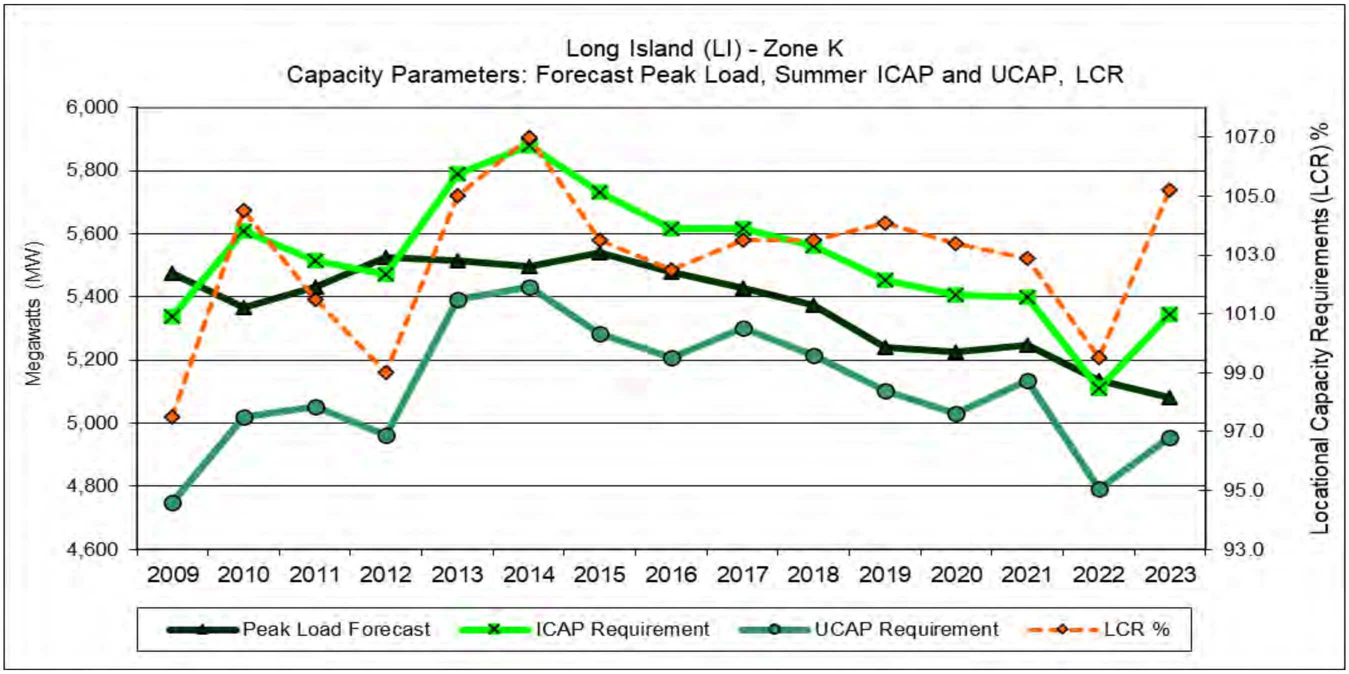
Year	Forecast Peak Load (MW)	Locational Capacity Requirement (%)	Derate Factor	ICAP Requirement (MW)	UCAP Requirement (MW)	Effective UCAP (%)
2009	12,050	80.0	0.0814	9,640	8,855	73.5
2010	11,725	80.0	0.1113	9,380	8,336	71.1
2011	11,514	81.0	0.0530	9,326	8,832	76.7
2012	11,500	83.0	0.0679	9,545	8,897	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



D.1.3 Long Island ICAP to UCAP Translation

Table D.4 Long Island ICAP to UCAP Translation

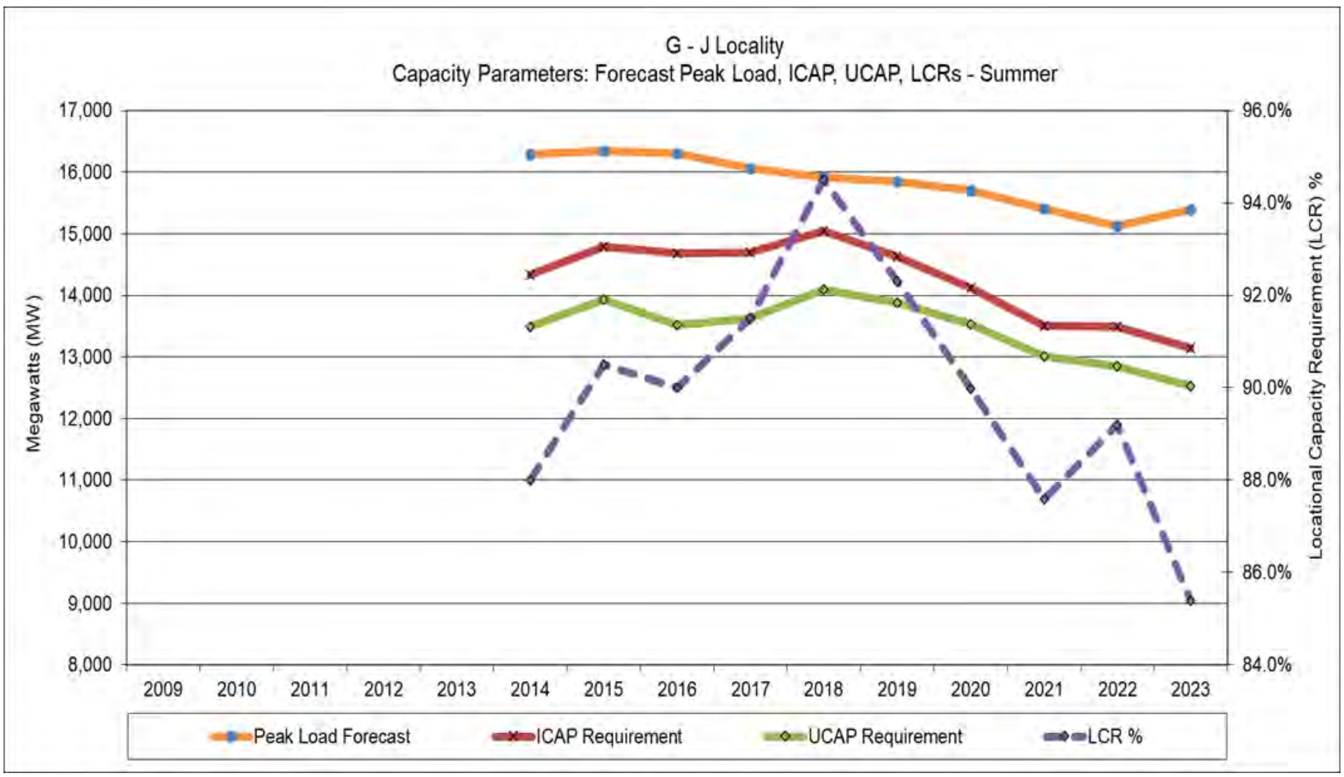
Year	Forecast Peak Load (MW)	Locational Capacity Requirement (%)	Derate Factor	ICAP Requirement (MW)	UCAP Requirement (MW)	Effective UCAP (%)
2009	5,474	97.5	0.1103	5,337	4,749	86.8
2010	5,368	104.5	0.1049	5,610	5,021	93.5
2011	5,434	101.5	0.0841	5,516	5,052	93.0
2012	5,526	99.0	0.0931	5,470	4,961	89.8
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



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 (%)
2014	16,291	88.0	0.0587	14,336	13,495	82.8
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

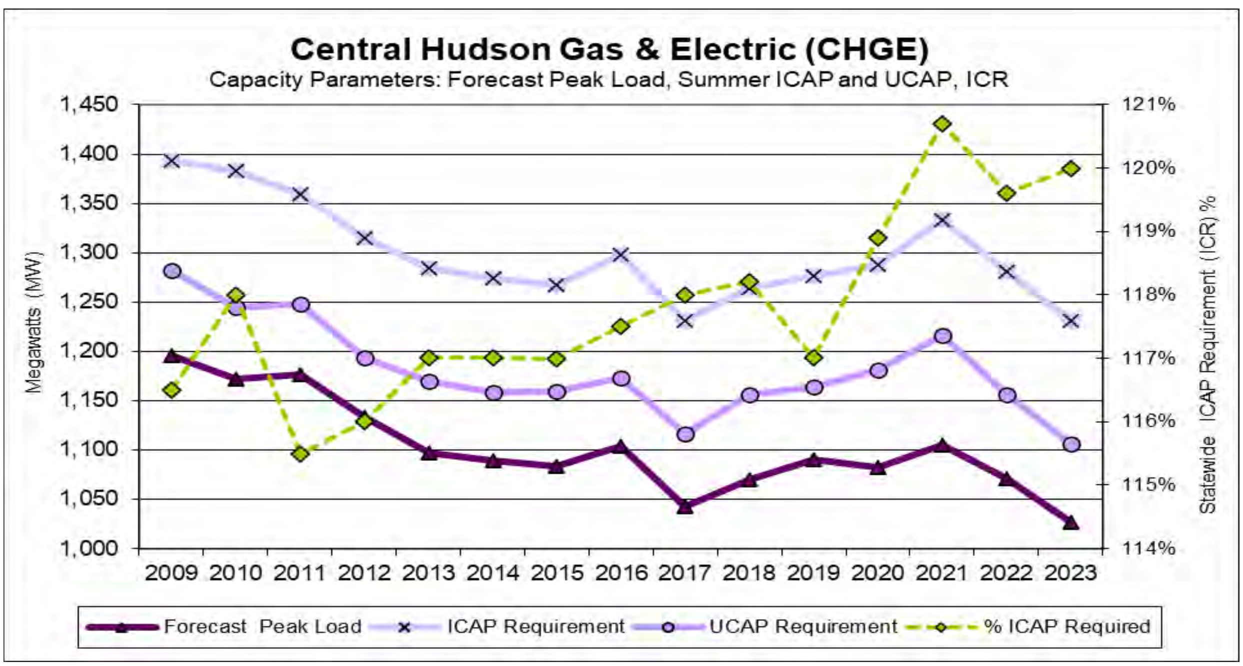


D.2 Transmission Districts ICAP to UCAP Translation

D.2.1 Central Hudson Gas & Electric

Table D.6 Central Hudson Gas & Electric ICAP to UCAP Translation

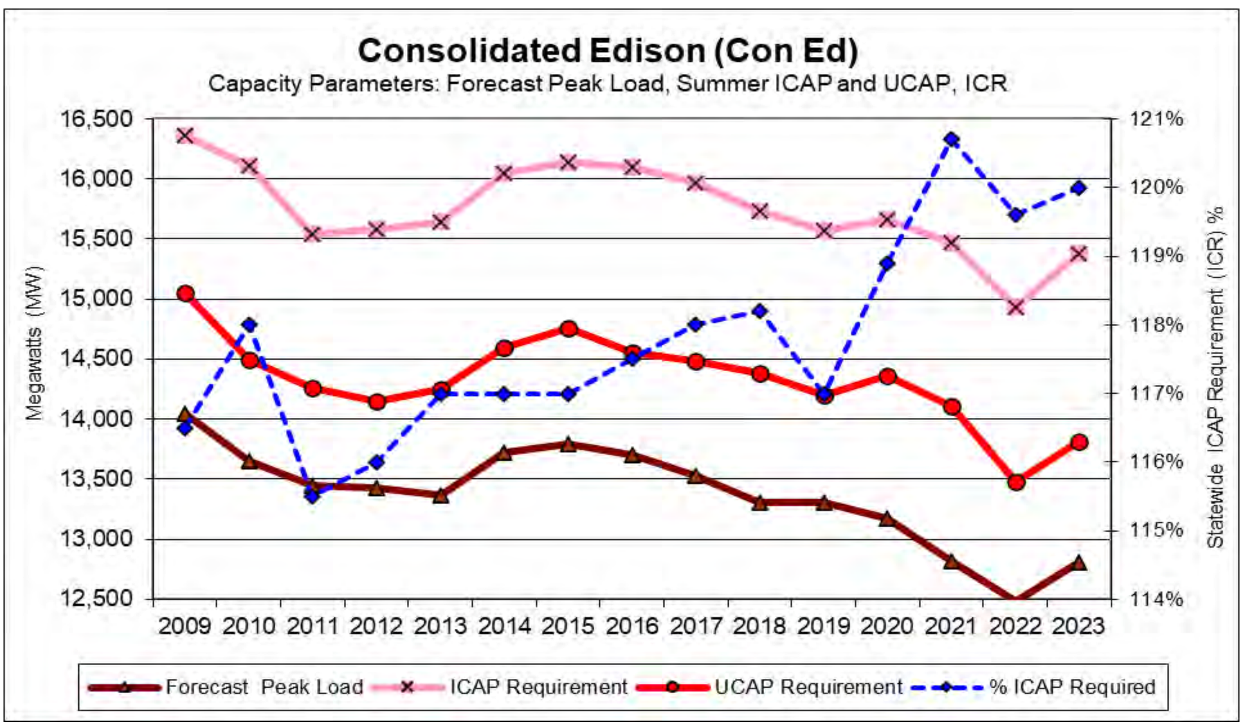
Year	Forecast Peak Load (MW)	ICAP Requirement (MW)	UCAP Requirement (MW)	% ICAP of Forecast Peak	% UCAP of Forecast Peak
2009	1,196.3	1,393.7	1,282.1	116.5%	107.2%
2010	1,172.3	1,383.3	1,244.0	118.0%	106.1%
2011	1,176.9	1,359.3	1,247.9	115.5%	106.0%
2012	1,133.3	1,314.6	1,193.9	116.0%	105.3%
2013	1,097.5	1,284.1	1,169.7	117.0%	106.6%
2014	1,089.2	1,274.4	1,158.7	117.0%	106.4%
2015	1,083.6	1,267.8	1,159.5	117.0%	107.0%
2016	1,104.2	1,297.4	1,172.7	117.5%	106.2%
2017	1,043.1	1,230.9	1,116.5	118.0%	107.0%
2018	1,069.7	1,264.4	1,156.2	118.2%	108.1%
2019	1,090.8	1,276.3	1,164.1	117.0%	106.7%
2020	1,082.7	1,287.3	1,180.5	118.9%	109.0%
2021	1,104.5	1,333.1	1,216.2	120.7%	110.1%
2022	1,071.3	1,281.3	1,156.0	119.6%	107.9%
2023	1,026.2	1,231.4	1,106.6	120.0%	107.8%



D.2.2 Consolidated Edison (Con Ed)

Table D.7 Con Ed ICAP to UCAP Translation

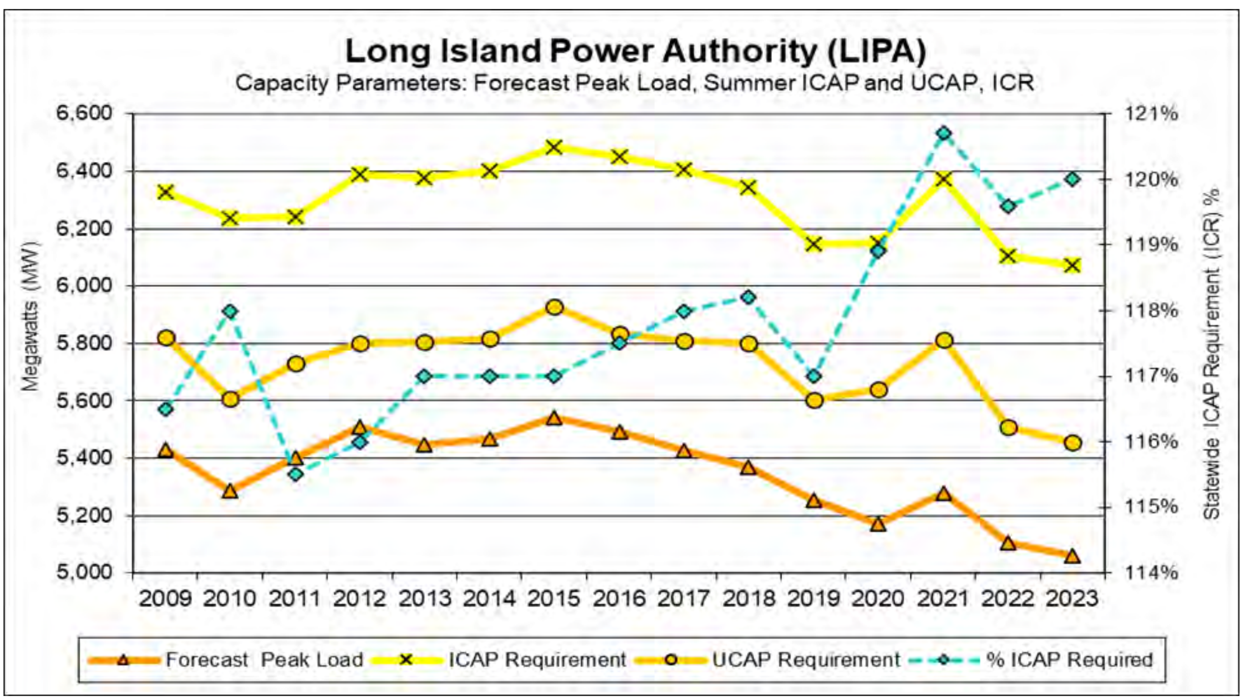
Year	Forecast Peak Load (MW)	ICAP Requirement (MW)	UCAP Requirement (MW)	% ICAP of Forecast Peak	% UCAP of Forecast Peak
2009	14,043.0	16,360.1	15,049.6	116.5%	107.2%
2010	13,654.9	16,112.8	14,490.2	118.0%	106.1%
2011	13,450.5	15,535.3	14,261.4	115.5%	106.0%
2012	13,430.5	15,579.4	14,149.2	116.0%	105.4%
2013	13,370.8	15,643.8	14,250.0	117.0%	106.6%
2014	13,718.7	16,050.9	14,593.5	117.0%	106.4%
2015	13,793.0	16,137.8	14,759.6	117.0%	107.0%
2016	13,704.6	16,102.9	14,555.4	117.5%	106.2%
2017	13,534.0	15,970.1	14,486.5	118.0%	107.0%
2018	13,309.6	15,732.0	14,385.3	118.2%	108.1%
2019	13,305.5	15,567.4	14,199.1	117.0%	106.7%
2020	13,170.0	15,659.1	14,359.4	118.9%	109.0%
2021	12,816.7	15,469.8	14,113.1	120.7%	110.1%
2022	12,488.0	14,935.7	13,474.9	119.6%	107.9%
2023	12,811.7	15,374.1	13,815.1	120.0%	107.8%



D.2.3 Long Island Power Authority (LIPA)

Table D.8 LIPA ICAP to UCAP Translation

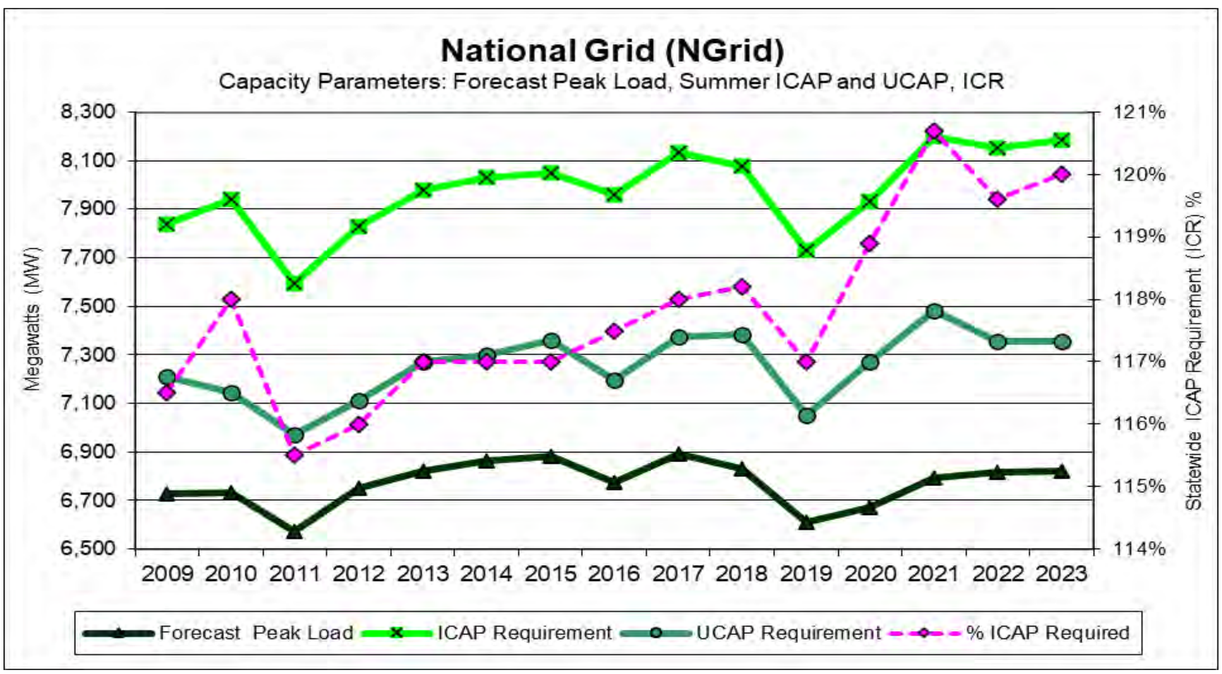
Year	Forecast Peak Load (MW)	ICAP Requirement (MW)	UCAP Requirement (MW)	% ICAP of Forecast Peak	% UCAP of Forecast Peak
2009	5,431.7	6,327.9	5,821.1	116.5%	107.2%
2010	5,286.0	6,237.5	5,609.4	118.0%	106.1%
2011	5,404.3	6,242.0	5,730.1	115.5%	106.0%
2012	5,508.3	6,389.6	5,803.1	116.0%	105.4%
2013	5,448.9	6,375.2	5,807.2	117.0%	106.6%
2014	5,470.1	6,400.0	5,818.9	117.0%	106.4%
2015	5,541.3	6,483.3	5,929.7	117.0%	107.0%
2016	5,491.3	6,452.3	5,832.2	117.5%	106.2%
2017	5,427.2	6,404.1	5,809.1	118.0%	107.0%
2018	5,368.1	6,345.1	5,802.0	118.2%	108.1%
2019	5,253.0	6,146.0	5,605.8	117.0%	106.7%
2020	5,172.9	6,150.6	5,640.1	118.9%	109.0%
2021	5,279.7	6,372.6	5,813.7	120.7%	110.1%
2022	5,105.1	6,105.7	5,508.6	119.6%	107.9%
2023	5,060.6	6,072.7	5,457.0	120.0%	107.8%



D.2.4 National Grid (NGRID)

Table D.9 NGRID ICAP to UCAP Translation

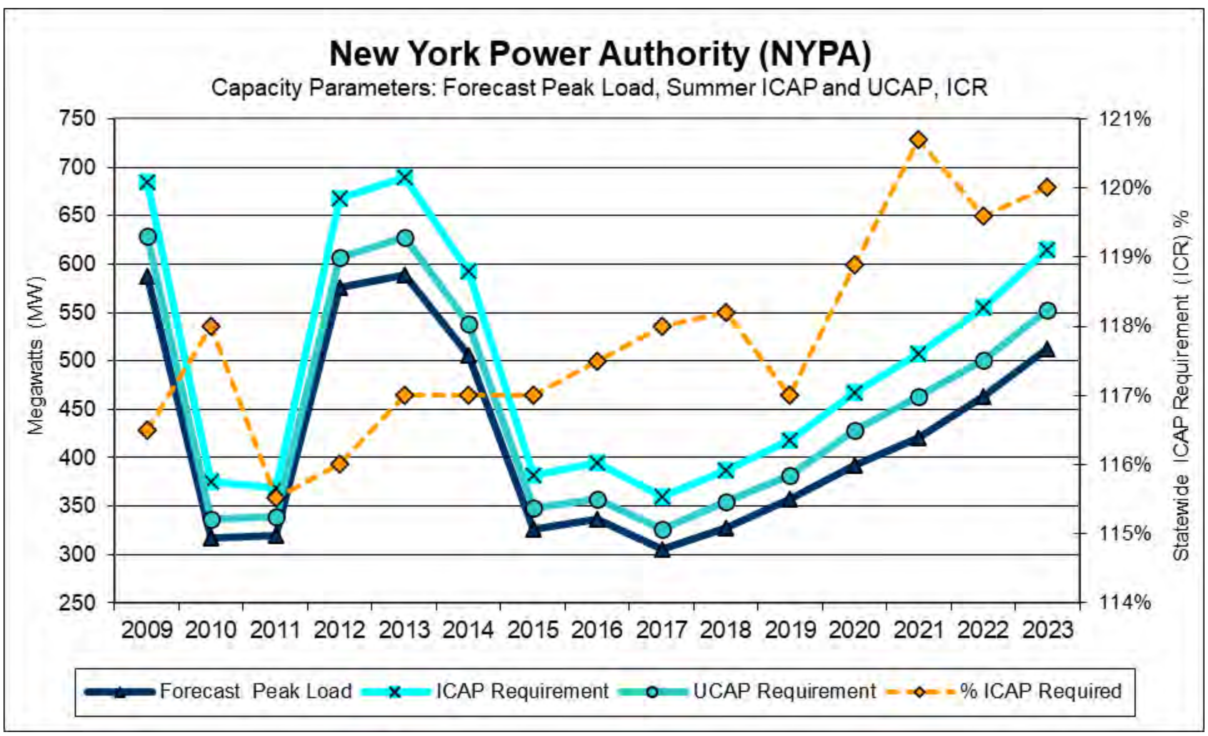
Year	Forecast Peak Load (MW)	ICAP Requirement (MW)	UCAP Requirement (MW)	% ICAP of Forecast Peak	% UCAP of Forecast Peak
2009	6,728.4	7,838.6	7,210.7	116.5%	107.2%
2010	6,732.1	7,943.9	7,144.0	118.0%	106.1%
2011	6,574.7	7,593.8	6,971.1	115.5%	106.0%
2012	6,749.1	7,828.9	7,110.3	116.0%	105.4%
2013	6,821.3	7,980.9	7,269.8	117.0%	106.6%
2014	6,861.9	8,028.4	7,299.4	117.0%	106.4%
2015	6,880.3	8,049.9	7,362.5	117.0%	107.0%
2016	6,776.0	7,961.8	7,196.7	117.5%	106.2%
2017	6,891.4	8,131.9	7,376.4	118.0%	107.0%
2018	6,833.0	8,076.6	7,385.2	118.2%	108.1%
2019	6,608.8	7,732.3	7,052.6	117.0%	106.7%
2020	6,670.2	7,930.9	7,272.6	118.9%	109.0%
2021	6,793.0	8,199.2	7,480.1	120.7%	110.1%
2022	6,817.1	8,153.3	7,355.9	119.6%	107.9%
2023	6,820.6	8,184.7	7,354.8	120.0%	107.8%



D.2.5 New York Power Authority (NYPA)

Table D.10 NYPA ICAP to UCAP Translation

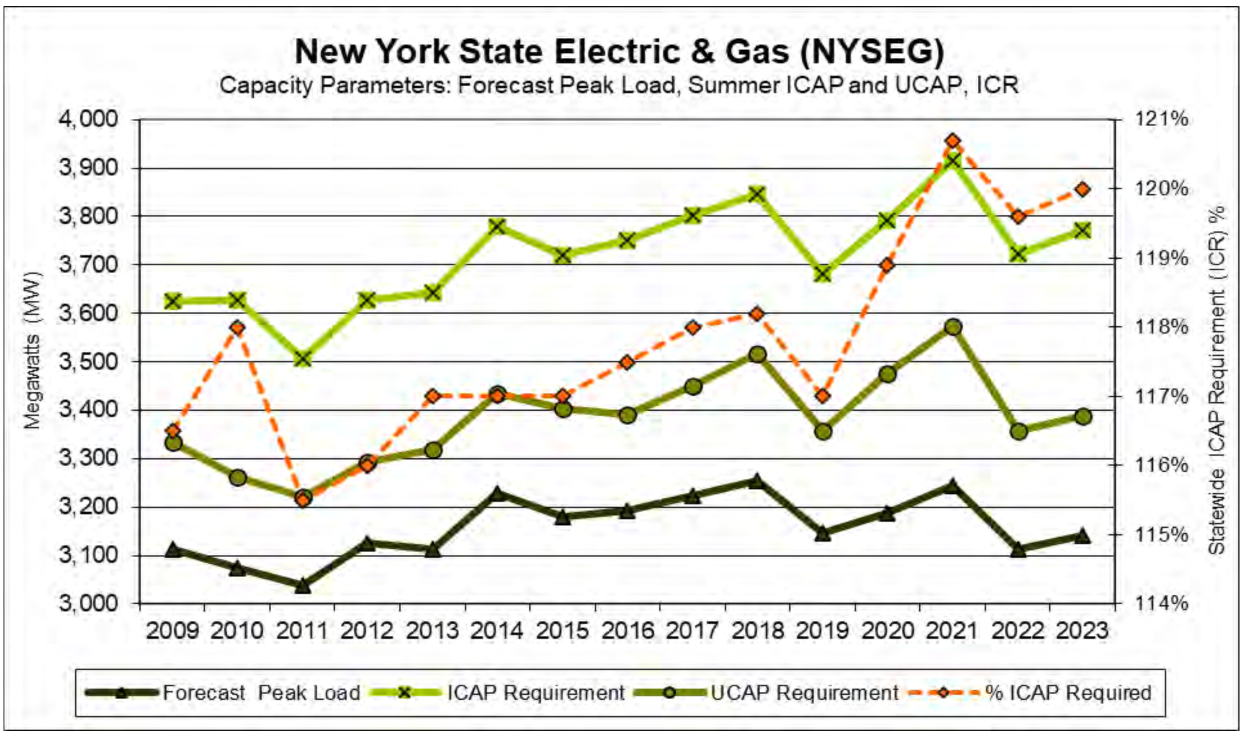
Year	Forecast Peak Load (MW)	ICAP Requirement (MW)	UCAP Requirement (MW)	% ICAP of Forecast Peak	% UCAP of Forecast Peak
2009	587.2	684.1	629.3	116.5%	107.2%
2010	317.6	374.8	337.0	118.0%	106.1%
2011	319.7	369.3	339.0	115.5%	106.0%
2012	576.1	668.3	606.9	116.0%	105.3%
2013	589.3	689.5	628.1	117.0%	106.6%
2014	506.3	592.4	538.6	117.0%	106.4%
2015	325.8	381.2	348.6	117.0%	107.0%
2016	336.0	394.8	356.9	117.5%	106.2%
2017	305.0	359.9	326.5	118.0%	107.0%
2018	327.6	387.2	354.1	118.2%	108.1%
2019	357.5	418.3	381.5	117.0%	106.7%
2020	392.7	466.9	428.2	118.9%	109.0%
2021	420.8	507.9	463.4	120.7%	110.1%
2022	463.8	554.7	500.4	119.6%	107.9%
2023	511.9	614.3	552.0	120.0%	107.8%



D.2.6 New York State Electric & Gas (NYSEG)

Table D.11 NYSEG ICAP to UCAP Translation

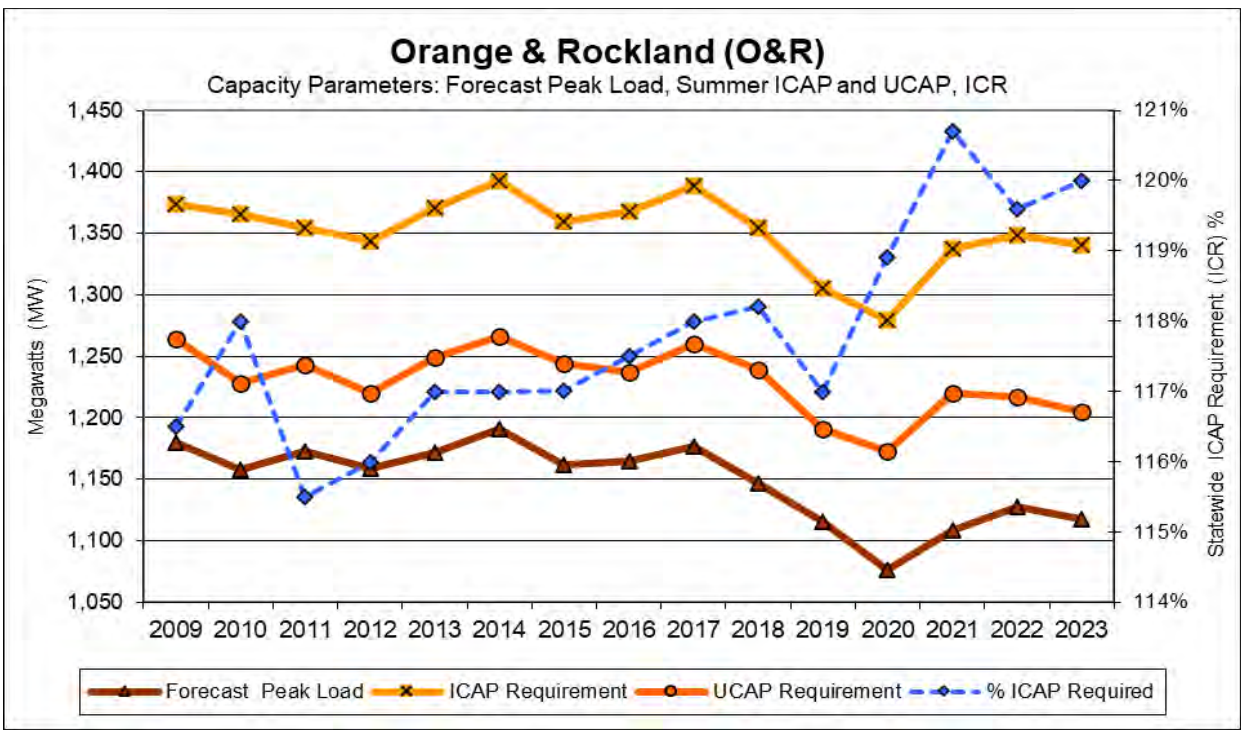
Year	Forecast Peak Load (MW)	ICAP Requirement (MW)	UCAP Requirement (MW)	% ICAP of Forecast Peak	% UCAP of Forecast Peak
2009	3,111.8	3,625.3	3,334.9	116.5%	107.2%
2010	3,075.0	3,628.5	3,263.1	118.0%	106.1%
2011	3,037.0	3,507.7	3,220.1	115.5%	106.0%
2012	3,126.7	3,627.0	3,294.0	116.0%	105.4%
2013	3,113.4	3,642.7	3,318.1	117.0%	106.6%
2014	3,229.1	3,778.1	3,435.0	117.0%	106.4%
2015	3,179.8	3,720.4	3,402.7	117.0%	107.0%
2016	3,191.6	3,750.1	3,389.7	117.5%	106.2%
2017	3,222.9	3,803.0	3,449.7	118.0%	107.0%
2018	3,254.0	3,846.2	3,517.0	118.2%	108.1%
2019	3,146.6	3,681.5	3,357.9	117.0%	106.7%
2020	3,188.4	3,791.0	3,476.3	118.9%	109.0%
2021	3,244.8	3,916.5	3,573.0	120.7%	110.1%
2022	3,112.4	3,722.4	3,358.4	119.6%	107.9%
2023	3,142.4	3,770.9	3,388.5	120.0%	107.8%



D.2.7 Orange & Rockland (O & R)

Table D.12 O & R ICAP to UCAP Translation

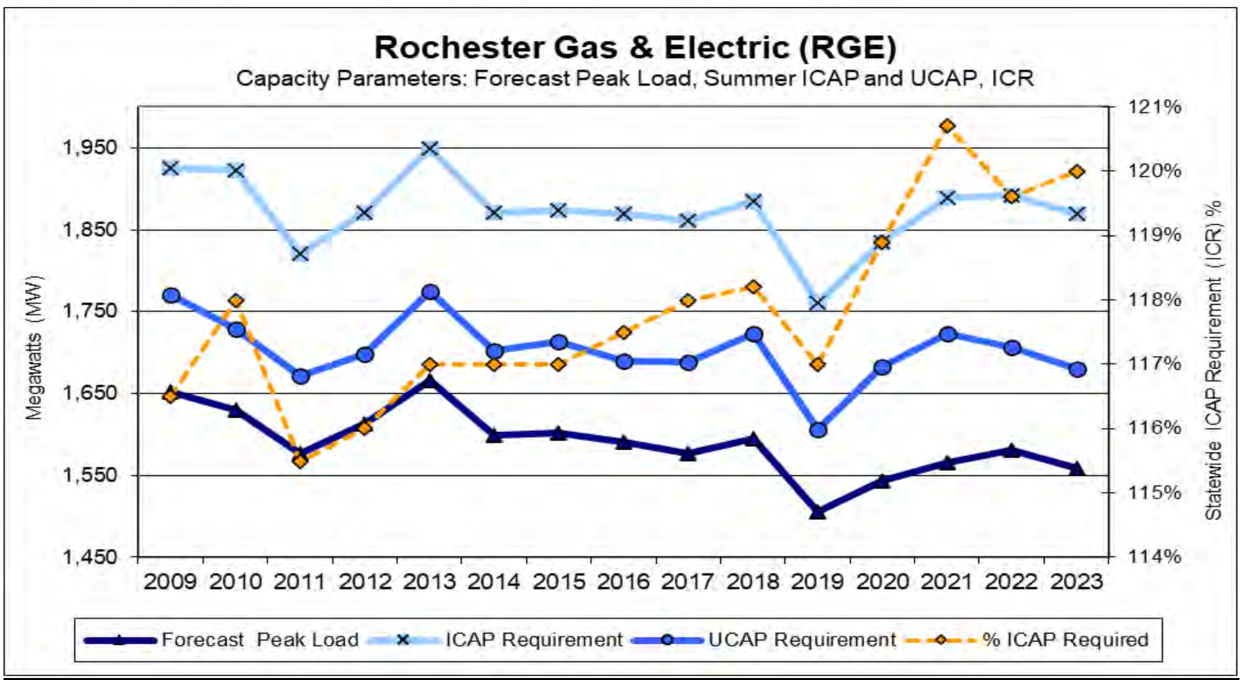
Year	Forecast Peak Load (MW)	ICAP Requirement (MW)	UCAP Requirement (MW)	% ICAP of Forecast Peak	% UCAP of Forecast Peak
2009	1,179.5	1,374.1	1,264.0	116.5%	107.2%
2010	1,157.4	1,365.7	1,228.2	118.0%	106.1%
2011	1,172.7	1,354.5	1,243.4	115.5%	106.0%
2012	1,158.3	1,343.6	1,220.3	116.0%	105.4%
2013	1,171.7	1,370.9	1,248.7	117.0%	106.6%
2014	1,190.8	1,393.2	1,266.7	117.0%	106.4%
2015	1,162.2	1,359.8	1,243.7	117.0%	107.0%
2016	1,164.3	1,368.1	1,236.6	117.5%	106.2%
2017	1,177.3	1,389.2	1,260.2	118.0%	107.0%
2018	1,146.2	1,354.8	1,238.8	118.2%	108.1%
2019	1,115.5	1,305.1	1,190.4	117.0%	106.7%
2020	1,075.9	1,279.3	1,173.1	118.9%	109.0%
2021	1,108.4	1,337.8	1,220.5	120.7%	110.1%
2022	1,127.7	1,348.7	1,216.8	119.6%	107.9%
2023	1,117.2	1,340.6	1,204.7	120.0%	107.8%



D.2.8 Rochester Gas & Electric (RGE)

Table D.13 RGE ICAP to UCAP Translation

Year	Forecast Peak Load (MW)	ICAP Requirement (MW)	UCAP Requirement (MW)	% ICAP of Forecast Peak	% UCAP of Forecast Peak
2009	1,652.3	1,924.9	1,770.7	116.5%	107.2%
2010	1,629.7	1,923.0	1,729.4	118.0%	106.1%
2011	1,576.4	1,820.7	1,671.4	115.5%	106.0%
2012	1,612.3	1,870.3	1,698.6	116.0%	105.4%
2013	1,665.7	1,948.9	1,775.2	117.0%	106.6%
2014	1,599.6	1,871.5	1,701.6	117.0%	106.4%
2015	1,601.3	1,873.5	1,713.5	117.0%	107.0%
2016	1,590.8	1,869.2	1,689.6	117.5%	106.2%
2017	1,576.9	1,860.7	1,687.9	118.0%	107.0%
2018	1,594.3	1,884.5	1,723.1	118.2%	108.1%
2019	1,505.5	1,761.4	1,606.6	117.0%	106.7%
2020	1,543.3	1,835.0	1,682.7	118.9%	109.0%
2021	1,565.2	1,889.2	1,723.5	120.7%	110.1%
2022	1,581.3	1,891.2	1,706.3	119.6%	107.9%
2023	1,558.3	1,870.0	1,680.3	120.0%	107.8%



D.3 Wind Resource Impact on the NYCA IRM and UCAP Markets

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

For a wind farm or turbine, 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 wind resource availability. For instance, off-shore wind will generally have higher availability and be more coincident with peak load hours than in-land wind. The effective capacity of wind generation can be either calculated statistically directly from historical hourly wind generation outputs, and/or by using the following information:

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

In general, effective wind capacity depends primarily on the availability of the wind. Wind farms in New York on average have annual capacity factors that are based on their nameplate ratings. A wind plant's output can range from close to nameplate under favorable wind conditions to zero when the wind does not blow. On average, a wind plant's output is higher at night, and has higher output on average in the winter versus the summer.

Another measure of a wind generator's contribution to resource adequacy is its effective capacity, which is its expected output during the summer peak hours of 2 p.m. to 6 p.m. for the months of June through August. The effective capacity value for wind generation in New York is based on actual hourly plant output over the previous five-year period – 2018 through 2022 for this year's study, for new units the zonal hourly averages or averages for nearby units will be used. Wind shapes years are selected randomly from those years for each simulation year.

In June 2023 the NYSRC issued a study entitled "Offshore Wind Data Review – NYSRC preliminary findings". This study raises concerns over the correlation in the availability and performance of offshore wind, both internal to the NYCA system, and more importantly across the Northeast region, especially between New York and New England. Currently the level of offshore wind modeled in the IRM study is low for NYCA and external areas. A study to assess the impact of correlated availability of offshore wind was attempted but showed no impact to the IRM due to only one offshore wind plant being modeled in NYCA and no offshore wind plant modeled in external areas in the IRM base case study database. In addition, the modeling of offshore wind, as well as other intermittent resources, in external areas is not consistent with the IRM approach. Modeling consistency is critical to capture the correlated availability or performance for offshore wind, and capturing such correlation should also be extended to other types of intermittent resources. Therefore, actions are being taken to urge NPCC to establish consistency in modeling and major assumptions across all neighboring systems. Additional sensitivity cases are also being considered for future studies to facilitate monitoring the impact on the IRM as offshore wind penetration increases over time.[10]

[10] https://www.nysrc.org/wp-content/uploads/2023/07/NYSRC-Wind-Impacts-Final-07_18_23.pdf

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.
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.
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.
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.

Term	Definition
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)	That capacity above firm system demand required to provide for equipment forced and scheduled outages and transmission capability limitations.
Interface	The specific set of transmission elements between two areas or between two areas comprising one or more electrical systems.
Load	The electric power 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.
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.

Term	Definition
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.
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.
Normalized Expected Unserved Energy	The Expected Unserved Energy (EUE) as a percent (%) of the total annual system net energy for load.

Term	Definition
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.
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	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.

Term	Definition
Zone	A defined portion of the NYCA area that encompasses a set of load and generation buses. Each zone has an associated zonal price that is calculated as a weighted average price based on generator LBMPs 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 zones, corresponding to ten major transmission interfaces that can become congested.