Technical Study Report

New York Control Area Installed Capacity Requirement

For the Period May ~~2024~~ 2025 to April ~~2025~~ 2026

~~December 8, 2023~~November 6, 2024

New York State Reliability Council, LLC
Installed Capacity Subcommittee

About the New York State Reliability Council

The New York State Reliability Council (NYSRC) is a not-for-profit corporation responsible for promoting and preserving the reliability of the New York State power system by developing, maintaining and, from time to time, updating the reliability rules which must be complied with by the New York Independent System Operator, Inc. (NYISO) and all entities engaging in electric power transactions on the New York State power system. One of the responsibilities of the NYSRC is the establishment of the annual statewide Installed Capacity Requirement for the New York Control Area.

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EXECUTIVE SUMMARY

A New York Control Area (NYCA) Installed Reserve Margin (IRM) Study is conducted annually by the New York State Reliability Council (NYSRC) Installed Capacity Subcommittee (ICS). ICS has the overall responsibility of managing studies for establishing NYCA IRM requirements for the upcoming Capability Year[1] including the development and approval of all modeling and database assumptions to be used in the reliability calculation process. This report covers the period May 1, ~~2024~~ 2025 through April 30, ~~2025~~ 2026 (~~2024~~ 2025 Capability Year). The IRM study described in this report for the ~~2024~~ 2025 Capability Year is referred to as the "~~2024~~ 2025-2026 IRM Study."

Results of the NYSRC technical study was performed pursuant to the NYSRC Policy for setting the Installed Reserve margin.[2] The report shows that the calculated NYCA IRM for the ~~2024~~ 2025 Capability Year is ~~23~~24.~~1~~4% under final base case assumptions. This IRM satisfies the NYSRC resource adequacy criterion of a Loss of Load Expectation (LOLE) of no greater than 0.1 Event-Days/year. The base case, along with other relevant factors, will be considered by the NYSRC Executive Committee on December ~~8~~6, ~~2023~~ 2024for its adoption of the Final NYCA IRM requirement for the ~~2024~~ 2025 Capability Year.

In addition to calculating the LOLE, the analysis also determined that the Hourly Loss of Load Expectation (LOLH) was 0.~~378~~ 374 hours per year and the Expected Unserved Energy (EUE) was ~~224.976~~216.980 MWh per year. For comparison to other systems, a Normalized Expected Unserved Energy (NEUE) can also be determined, which divides the EUE by the expected load energy. Using the NYISO's projected ~~2024~~ 2025 NYCA energy value of ~~152,140~~150,540 GWh/year (~~2023~~ 2024 Gold Book) this produces a NEUE of 0.~~00015~~00014%. Other systems around the world that design to LOLH have a criteria of less than 3 to 8 hours per year. Criteria based on NEUE is typically less than 0.002%. Both of the NYCA results represent a significantly higher level of reliability than either of these criteria.[3]

The NYSRC study procedure used to establish the NYCA IRM[4] also produces corresponding "Minimum Locational Capacity Requirements" (MLCRs) for New York City and Long Island locational to satisfy the NYCA resource adequacy criterion, along with the calculated NYCA IRM. The ~~2024~~ 2025-2026 IRM

[1] A Capability Year begins on May 1 and ends on April 30 of the following year.

[2] Policy No. 5-17; Procedure for Establishing New York Control Area Installed Capacity Requirements. *See, Policy 5-17*

[3] Resource Adequacy for a Decarbonized Future. https://www.epri.com/research/products/000000003002023230

[4] This procedure is described in Section 3, IRM Study Procedures. This procedure for calculating IRM requirements and initial LCRs is sometimes referred in this report to as the "Tan 45 process."

Study determined related MLCRs of ~~72.7~~75.6% and ~~103.2~~107.3% for the New York City and Long Island localities, respectively. This represents an ~~decrease~~ increase of ~~5.5~~4.1% for NYC and an ~~decrease~~ increase of ~~4.2~~2.9% in Long Island from the MLCRs determined as part of the ~~2023~~ 2024-2025 IRM Study. In accordance with its responsibility of setting the Locational Minimum Installed Capacity Requirements (LCRs), the NYISO will calculate and approve *final LCRs* for all NYCA localities using a separate process that utilizes the NYSRC approved Final IRM and adheres to NYSRC Reliability Rules and policies.

The ~~23.1~~24.4% IRM base case value for the ~~2024~~ 2025 Capability Year represents a *~~3.2~~1.3% increase* from the ~~2023~~ 2024 base case IRM of ~~19.9~~23.1%. Table 6-1 shows the IRM impacts of individual updated study parameters that result in this change. In summary:

- There are fourteen parameter drivers that in combination *increased* the 2025 IRM from the 2024 base case IRM by 4.354%. Of these fourteen drivers, the most significant was the limit on EOP calls which increased the IRM by 1.02%. The next three most significant are the addition of the new renewable generators which increased the IRM by 0.63%, the change ~~-~~in SCR capacities which increased the IRM by 0.53% and the change in generator ratings which increased the IRM by 0.41%. The remaining changes had relatively minor changes in the IRM.
- Seven parameter drivers in combination *decreased* the IRM from the ~~2022~~2024 base case by 1.49%. Of these seven drivers, the most significant was the change in the SCR modeling which decreased the IRM by 0.57%. All other modifications had less than a 0.3% impact.

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- ~~There are eleven parameter drivers that in combination *increased* the 2024 IRM from the 2023 base case IRM by 4.89%. Of these eleven drivers, the most significant was the reduction in emergency assistance import limits in the higher load bins which increased the IRM by 2.24%. The next three most significant are the change in cable transition rates which increased the IRM by 0.59%, the increase in thermal outage rates which increased the IRM by 0.43% and the addition of 90 MW of solar generation which increased the IRM by 0.34%. This was followed by the change in topology related to the "AC Transmission" upgrades and the withholding of an additional 50 MW of Operating Reserves at load shedding which both increased the IRM by 0.25%. Bringing back certain peaking generation units or "peakers" which had been assumed for deactivation in the 2023 IRM Study increased the IRM by 0.23% and the addition of 136 MW of offshore wind units which increased the IRM by 0.19%. Updates in the performance and quantity of the Special Case Resources (SCRs) increased the IRM by 0.14%. The change in run-of-river hydro generation shapes caused a 0.13% increase. Lower Dependable Maximum Net Capability (DMNC) ratings in the down-state areas increased the IRM by 0.1%.~~

- ~~Seven parameter drivers in combination *decreased* the IRM from the 2023 base case by 1.59%. Of these seven drivers, the most significant was the expected increase in the amount of Behind-the Meter (BTM) Solar generation which decreased the IRM by 0.5%. Modifications in the External Areas and the subsequent Policy 5 adjustments resulted in a 0.37% decrease in IRM. Changes in the 2023 Load Forecasts (including the Fall Forecast), which resulted in a slight peak load increase across the system, resulted in a 0.20% reduction in the IRM. The Load Forecast Uncertainty (LFU) model was adjusted slightly and resulted in a 0.14% IRM reduction. Shifting the Wind shapes forward by a year resulted in a 0.11% decrease in IRM. A slight increase in the value of the voltage reductions reduced the IRM by 0.11%.~~

The complete parametric analysis showing the above and other results can be found in Section 6 in this report.

This study also evaluated IRM impacts of several sensitivity cases. The results of these sensitivity cases are discussed in Section 7 and summarized in Table 7-1. The base case IRM and sensitivity case results, along with other relevant factors, will be considered by the NYSRC Executive Committee in adopting the Final NYCA IRM requirement for the ~~2024~~ 2025 Capability Year. NYSRC Policy 5-17 describes the Executive Committee process for establishing the final IRM.

Transmission security limit (TSL) floors are inputs to the NYISO's LCR study and are not considered in the IRM under the Tan 45 process described in Policy 5-17. In this year's analysis, two of the preliminary TSL floor values are well below the MLCRs determined from the IRM analysis and only the NYC MLCR is slightly above. When all three TSL floors are incorporated into this year's NYISO LCR study, there will be a situation where locking the Tan 45 IRM results in a system that is noticeably worse than 0.1 Event-Days/year. Because this year had more flexibility, the LCR Optimizer was able to achieve an LOLE of 0.100 Event-Days/year at the calculated 24.4% IRM with only slight adjustments to the LCR values.

~~Transmission security limit (TSL) floors are inputs to the NYISO's LCR study and are not considered in the IRM under the Tan 45 process described in Policy 5-17. There are significant gaps between the MLCRs from the Tan 45 results and the TSL floors in this year's IRM study, which results in a greater reliability than the 0.1 Event Days/year criteria based on LCRs that account for the TSL floors. Additional assessments considering the TSL floors are conducted and discussed in Section 4.~~

In addition, a confidence interval analysis was conducted to demonstrate that there is a high confidence that the base case ~~23.1~~24.4% IRM will fully meet NYSRC and Northeast Power Coordinating Council (NPCC) resource adequacy criterion that require a LOLE of no greater than 0.1 Event-Days/year.

The ~~2024~~ 2025-2026 IRM Study also evaluated Unforced Capacity (UCAP) trends. The NYISO values capacity sold and purchased in the market in a manner that considers the forced outage ratings of individual units, whereby generating unit capacity is derated to an unforced capacity basis recognizing the impact of forced outages. This derated capacity is referred to as "UCAP." This analysis shows that required UCAP margins, which steadily decreased over the 2006-2012 period to about 5%, remained relatively steady through 2019 but have increased through 2021 (see Figure 8-1). Due to lower contributions to reliability, the increase in wind resources lowers the translation factor from required ICAP to required UCAP which reflects the performance of all resources on the system.

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1. Introduction

This report describes a technical study, conducted by the NYSRC Installed Capacity Subcommittee (ICS), for establishing the NYCA Installed Reserve Margin (IRM) for the period of May 1, ~~2024~~ 2025 through April 30, ~~2025~~ 2026 (~~2024~~ 2025 Capability Year). This study is conducted each year in compliance with Section 3.03 of the NYSRC Agreement, which states that the NYSRC shall establish the annual statewide Installed Capacity Requirement (ICR) for the NYCA. The ICR relates to the IRM through the following equation:

$$\text{ICR} = \left(1 + \frac{\text{IRM Requirement (\%)}}{100}\right) * \text{Forecast NYCA Peak Load}$$

The base case and sensitivity case study results, along with other relevant factors, will be considered by the NYSRC Executive Committee for its adoption of the Final NYCA IRM requirement for the ~~2024~~ 2025 Capability Year.

The NYISO will implement the Final NYCA IRM as determined by the NYSRC, in accordance with the NYSRC Reliability Rules, NYSRC Policy 5-17, *Procedure for Establishing New York Control Area Installed Capacity Requirement and the Installed Reserve Margin (IRM)*;[5] the NYISO Market Administration and Control Area Services Tariff; and the NYISO Installed Capacity (ICAP) Manual.[6] The NYISO translates the required IRM to a UCAP basis. These values are also used in ICAP Spot Market Auctions based on FERC-approved ICAP Demand Curves. The schedule for conducting the ~~2024~~ 2025-2026 IRM Study was based on meeting the NYISO's timetable for conducting such auctions.

The study criteria, procedures, and types of assumptions used for the study for establishing the NYCA IRM for the ~~2024~~ 2025 Capability Year (~~2024~~ 2025-2026 IRM Study) are set forth in NYSRC Policy 5-17. The primary reliability criterion used in the IRM study requires a LOLE of no greater than 0.1 Event-Days/year for the NYCA. This NYSRC resource adequacy criterion is consistent with the Northeast Power Coordinating Council (NPCC) resource adequacy criterion. IRM study procedures include the use of two reliability study methodologies: The *Unified Methodology* and the *IRM Anchoring Methodology.* NYSRC reliability criteria and IRM study methodologies and models are described in Policy 5-17 and discussed in detail later in this report.

[5] http://www.nysrc.org/policies.asp

[6] http://www.nyiso.com/public/markets_operations/market_data/icap/index.jsp

The NYSRC procedure for determining the IRM also identifies corresponding "Minimum Locational Capacity Requirements" (MLCRs) for the New York City and Long Island localities. The NYISO, using a separate process – in accordance with the NYISO tariffs and procedures, while adhering to NYSRC Reliability Rules and NYSRC Sections 3.2 and 3.5 of Policy 5-17 – is responsible for setting *final* LCRs for the New York City, Long Island and G-J Locality. For its determination of LCRs for the ~~2024~~ 2025 Capability Year, the NYISO will continue utilizing an economic optimization methodology approved by the Federal Energy Regulatory Commission.

The ~~2024~~ 2025-2026 IRM Study was managed and conducted by the NYSRC ICS and supported by technical assistance from the NYSRC's technical consultants and the NYISO staff.

Previous IRM Study reports, from year 2000 to year ~~2023~~2024, can be found on the NYSRC website.[7] Appendix D, Table D.1 provides a record of previous NYCA base case and final IRMs for the 2000 through ~~2023~~ 2024 Capability Years. Figure 8-1 and Appendix D, Table D.1.1, show UCAP reserve margin trends over previous years. Definitions of certain terms in this report can be found in the Glossary (Appendix E).

Different reliability analyses, separate from the IRM study process covered in this report, are conducted by the NYISO and are called the Reliability Needs Assessment (RNA) and the Short-Term Assessment of Reliability (STAR). These analyses assess the resource adequacy and transmission security of the NYCA for ten years into the future. The RNA is conducted once every two years and examines years four through ten of the study period, while the STAR is conducted quarterly and analyzes years one through five, with a focus on fulfilling any identified reliability needs in years one through three. These assessments determine whether the NYSRC resource adequacy reliability criterion, as defined in Section 2 below, is expected to be maintained over the study period; and if not, identifies reliability needs or compensatory MW of capacity or other measures of solutions required to meet those needs.

2. NYSRC Resource Adequacy Reliability Criterion

The required reliability level used for establishing NYCA IRM Requirements is dictated by Requirement 1.1 of NYSRC Reliability Rule A.1, *Establishing NYCA Statewide Installed Reserve Margin Requirements,* which states that the NYSRC shall:

> *Probabilistically establish the IRM requirement for the NYCA such that the loss of load expectation (LOLE) of disconnecting firm load due to resource deficiencies shall be, on*

[7] https://www.nysrc.org/documents/reports/nysrc-new-york-control-area-installed-capacity-requirement-reports/

average, no more than 0.1 Event-Days/year. This evaluation shall make due allowances for demand uncertainty, scheduled outages and de-ratings, forced outages and de-ratings, assistance over interconnections with neighboring control areas, NYS Transmission System emergency transfer capability, and capacity and/or load relief from available operating procedures.

The above NYSRC Reliability Rule is consistent with NPCC's Resource Adequacy criterion in NPCC Directory 1, *Design and Operation of the Bulk Power System*. This criterion is interpreted to mean that planning reserve margins, including the IRM, needs to be high enough that the probability of an involuntary load shedding due to inadequate resources is limited to only one event-day in ten years or 0.1 Event-Days/ year. This criterion has been widely accepted by most electric power systems in North America for reserve capacity planning. In New York, use of the LOLE criterion of 0.1 Event-Days/year has provided an acceptable level of reliability for many years.

In addition to calculating the LOLE reliability metric the calculations shall also include the calculation and reporting of Loss of Load Hours (LOLH) and Expected Unserved Energy (EUE) reliability metrics in the probabilistic resource capacity assessments.

In accordance with NYSRC Reliability Rule A.2, Establishing Load Serving Entity (LSE) Installed Capacity Requirements, the NYISO is required to establish LSE installed capacity requirements, including LCRs, for meeting the statewide IRM requirement established by the NYSRC in compliance with NYSRC Reliability Rule A.1 above.

3. IRM Study Procedures

The study procedures used for the ~~2024~~ 2025-2026 IRM Study are described in detail in NYSRC Policy 5-17, *Procedure for Establishing New York Control Area Installed Capacity Requirements and the Installed Reserve Margin (IRM)*. Policy 5-17 also describes the computer program used for reliability calculations and the types of input data and models used for the IRM Study.

This study utilizes a *probabilistic approach* for determining NYCA IRM requirements. This technique calculates the probabilities of generator unit outages, in conjunction with load and transmission representations, to determine the Event-Days per year of expected resource capacity shortages.

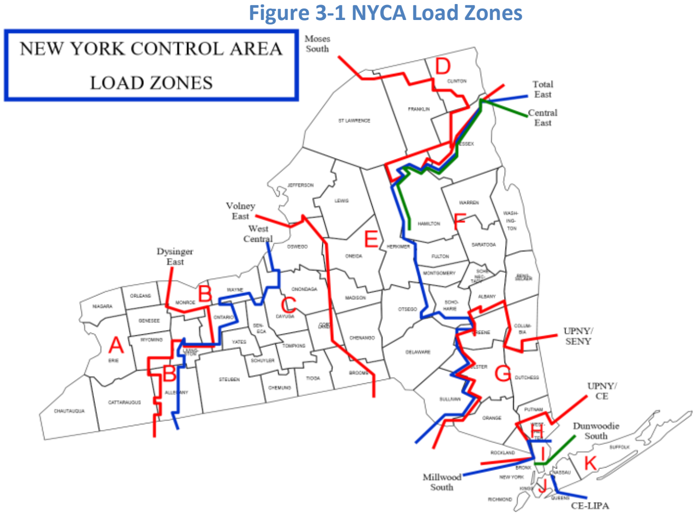
General Electric's Multi-Area Reliability Simulation (GE-MARS) is the primary computer program used for this probabilistic analysis. This program includes detailed load, generation, and transmission representation for eleven NYCA load zones — plus four Outside World Control Areas (Outside World Areas) directly interconnected to the NYCA. The Outside World Areas are as follows: Ontario, New

England, Quebec, and the PJM Interconnection. The eleven NYCA zones are depicted in Figure 3-1. GE-MARS calculates LOLE, expressed in Event-Days/year, to provide a consistent measure of system reliability. The GE-MARS program is described in detail in Appendix A, Section A.1.

Prior to the 2016-2017 IRM Study, the IRM base case and sensitivity analyses were simulated using only weekday peak loads rather than evaluating all 8,760 hours per year in order to reduce computational run times. However, the 2016-2017 IRM Study determined that the difference between study results using the daily peak hour versus the 8,760-hour methodologies would be significant. Therefore, the base case and sensitivity cases in the 2016-2017 IRM Study and all later studies, including this ~~2024~~ 2025-2026 IRM Study, were simulated using all hours in the year.

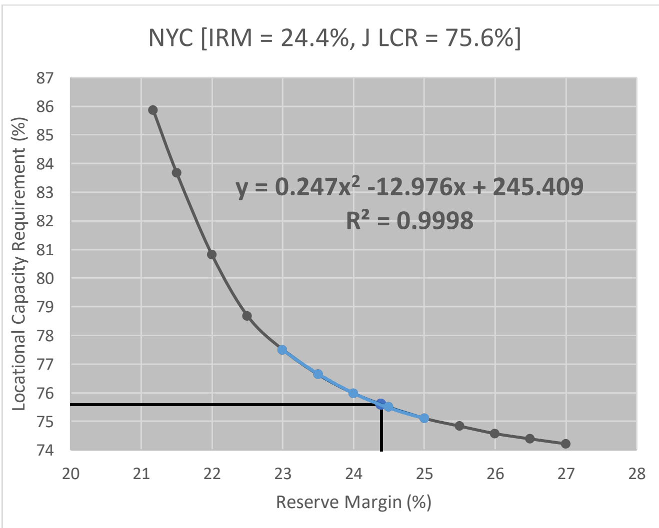
Using the GE-MARS program, a procedure is utilized for establishing NYCA IRM requirements (termed the *Unified Methodology*) which establishes a relationship between NYCA IRM and corresponding MLCRs, as illustrated in Figure 3-2. All points on these curves meet the NYSRC 0.1 Event-Days/year LOLE reliability criterion described in Section 2. Note that the area above the curve is more reliable than the criterion, and the area below the curve is less reliable. This methodology develops a pair of curves for two zones with locational capacity requirements, New York City (NYC), Zone J; and Long Island (LI), Zone K. Appendix A of NYSRC Policy 5-17 provides a more detailed description of the Unified Methodology.

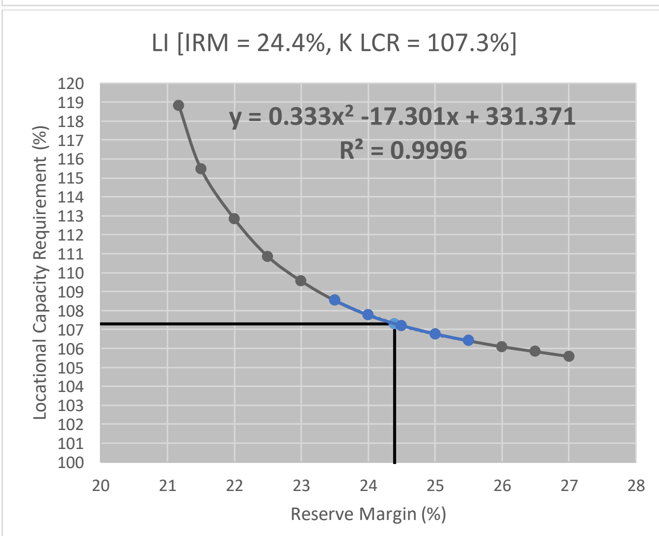
Figure 3-1 NYCA Load Zones



Base case NYCA IRM requirements and corresponding initial locality reserve margins for Zones J and K are established by a supplemental procedure (termed the *IRM Anchoring Methodology*), which is used to define an *inflection point* on each of these curves. These inflection points are selected by applying a tangent of 45 degrees (Tan 45) analysis at the bend (or "knee") of each curve. Mathematically, each curve is fitted using a second order polynomial regression analysis. Setting the derivative of the resulting set of equations to minus one yields the points at which the curves achieve the Tan 45-degree inflection point. Appendix B of NYSRC Policy 5-17 provides a more detailed description of the methodology for computing the Tan 45 inflection point.

Figure 3-2 Relationship Between NYCA IRM and Corresponding Initial Locational Capacity Requirements for ~~2024~~ 2025 IRM





4. Study Results – Base Case

Results of the NYSRC technical study show that the calculated NYCA IRM is ~~23.1~~24.4~~2~~% for the ~~2024~~ 2025 Capability Year under final base case assumptions. Figure 3-2 on the previous page depicts the relationship between NYCA IRM requirements and corresponding MLCRs for New York City and Long Island.

The tangent points on these curves were evaluated using the Tan 45 analysis described in Section 3. Accordingly, maintaining a NYCA IRM of ~~23.1~~24.4% for the ~~2024~~ 2025 Capability Year, together with corresponding MLCRs of ~~72.7~~75.6 % and ~~103.2~~107.3% for New York City and Long Island, respectively, will achieve applicable NYSRC and NPCC reliability criteria for the base case study assumptions shown in Appendix A.3.

Comparing the corresponding MLCRs in this ~~2024~~ 2025-2026 IRM Study to ~~2023~~ 2024-2025 IRM Study results (New York City LCR= ~~78.2~~72.7%, Long Island LCR= ~~107.4~~103.2%), the corresponding ~~2024~~ 2025 New York City MLCR ~~decreased~~ increased by ~~5.5~~2.9%, ~~while~~ and the corresponding Long Island MLCR ~~decreased~~ increased by 4.~~2~~1%. ~~The primary driver for the decrease in Long Island MLCR was updated Unforced Capacity Deliverability Rights (UDR) elections in the locality~~. The key factors in the ~~reduction~~ increase of the NYC MLCR was a reduction in ~~cable transition rates and the "AC Transmission" changes which allowed increased flows into NYC~~the number of EOP calls for voluntary curtailments and public appeals as well as a reduction in the fall load forecast.

In accordance with NYSRC Reliability Rule A.2, *Load Serving Entity ICAP Requirements,* the NYISO is responsible for separately calculating and establishing the final LCRs. The NYISO will calculate and approve *final LCRs* for all NYCA localities using a separate process that utilizes the NYSRC approved Final IRM and adheres to NYSRC Reliability Rules and policies.

For this analysis, the Base Case required 1,050 replications to converge to a standard error of 0.05 and required ~~3,237~~4,236 replications to converge to a standard error of 0.025. For our cases, the model was run to ~~3~~4,250 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~~24.3% to ~~23.3~~24.7%. It should be recognized that an IRM of ~~23.1~~24.4% is in full compliance with the NYSRC Resource Adequacy rules and criteria (see Base Case Study Results section).

Transmission security limit (TSL) floors are inputs to the NYISO's LCR study and are not considered in the IRM under the Tan 45 process described in Policy 5-17. In this year's analysis two of the preliminary TSL floor values are well below the MLCRs determined from the IRM analysis and only the NYC MLCR is slightly above. When all three TSL floors are incorporated into this year's NYISO LCR study there will be a situation where locking the Tan 45 IRM results in a system that is noticeably ~~better~~ worse than

0.1 Event-Days/year. Because this year had more flexibility the LCR Optimizer was able to achieve an LOLE of 0.100 Event-Days/year at the calculated 24.4% IRM with only slight adjustments to the LCR values. The results are shown in the table below. ~~The typical process is for NYISO to take the NYSRC approved IRM and use that value in the LCR study. In this instance, because the IRM would be locked at the NYSRC approved IRM, the model can only make LCR adjustments to achieve a LOLE of 0.1 Event-Days/year. Because the New York City and Long Island MLCRs are below the TSL floors the model will increase New York City and Long Island LCRs to the TSL floor and to achieve the same IRM, the only option left to adjust is the G-J Locality LCR. The G-J Locality LCR can only be adjusted down to 81% before hitting the applicable TSL floor. Doing so would result in a system that is better than criterion at 0.069 Event-Days/year. NYISO performed an additional analysis that locked in the LCRs at the TSL floors and adjusted the IRM to get back to criterion of 0.1 Event-Days/year. The results, which are shown in the table below, produced an IRM of 21.5%. This additional analysis is presented for informational purposes and does not replace the official Tan 45 IRM results of 23.1%.~~

Table 4.1 Supplementary analysis of TSL floors

	IRM	Preliminary LCRs			
		NYC	LHV	LI	LOLE (Event-Days/yr)
~~2024~~ 2025 FBC Tan 45	~~23.10~~24.4%	~~72.73~~75.6%	~~84.58~~86.9%	~~103.21~~107.3%	0.100
TSL Floors		~~81.70~~78.5%	~~81.00~~78.8%	~~105.30~~103.0%	
Tan 45 IRM + TSL Floors	23.1%	81.70%	81.00%	105.30%	0.069
Adjust IRM + TSL Floors	21.50%	81.70%	81.00%	105.30%	0.100

Commented [BP1]: TBD

Commented [BP2]: TBD

5. Models and Key Input Assumptions

This section describes the models and related base case input assumptions for the ~~2024~~ 2025-2026 IRM Study. The models represented in the GE-MARS analysis include a *Load Model, Capacity Model, Transmission Model, and Outside World Model*. A *Database Quality Assurance Review* of the ~~2024~~ 2025-2026 base case assumptions ~~is~~are also addressed in this section. The input assumptions for the final base case were approved by the Executive Committee on October ~~13, 2023~~10, 2024. Appendix

A, Section A.3 provides more details of these models and assumptions and comparisons of several key assumptions with those used for this ~~2024~~ 2025-2026 IRM Study.

5.1 The Load Model

5.1.1 Peak Load Forecast

The NYCA peak load forecast is based upon a model that incorporates forecasts of economic drivers, end use and technology trends, and normal weather conditions. A ~~2024~~ 2025 NYCA summer peak load forecast of ~~31,765.6~~31,649.7 MW was assumed in the ~~2024~~ 2025 IRM Study, a decrease of ~~480.4~~115.9 MW from the forecast used in the ~~2023~~ 2024-2025 IRM Study. This “Fall ~~2024~~ 2025 Summer Load Forecast” was prepared for the ~~2024~~ 2025-2026 IRM Study by the NYISO staff in collaboration with the NYISO Load Forecasting Task Force and presented to the ICS on October 4, 2024~~4, 2023~~ (~~2024~~ 2025 Fall Load Forecast). The ~~2024~~ 2025 Fall Load F~~f~~orecast considered actual ~~2023~~ 2024 summer load conditions.

The peak load forecast changes are shown on Table 5-1 below. Relative to the ~~2023~~ 2024-2025 IRM Study forecast, the load forecast for the ~~2024~~ 2025 IRM Study has ~~decreased~~ increased in Zones A through I, and decreased in Zone J, and Zone K. ~~Actual experienced and weather normalized peak load levels in summer 2023 were generally lower than in recent years~~. The primary factors behind year over year load declines are the continued strong load-reducing impact of state policy incented energy efficiency programs, and behind-the-meter (BTM) solar installations. A secondary factor is slower economic growth relative to projections used for prior forecasts. In future years, electrification of vehicles and building appliances is expected to add to summer peak load levels. At this point, these positive load impacts are generally smaller than the load-reducing impacts of energy efficiency and BTM solar generation.

Table 5-1: Comparison of ~~2023~~ 2024 and ~~2024~~ 2025 Actual and Forecast Coincident Peak Summer Loads (MW)

	Fall ~~2023~~ 2024 Forecast	~~2023~~ 2024 Actual	~~2023~~2024 Normalized[8]	Fall ~~2024~~ 2025 Forecast	Forecast Change
	(a)	(b)	(c)	(d)	= (d) – (a)

[8] The “normalized” ~~2023~~ 2024 peak load reflects an adjustment of the actual ~~2023~~ 2024 peak load to account for the load impact of actual weather conditions, demand response programs, and municipal utility self-generation.

Zones A-I	~~15,828~~15,515	~~13,703~~14,110	~~15,114~~15,565	~~15,515~~15,831	~~-313~~316
Zones J&K	~~16,418~~16,284	~~15,020~~14,880	~~16,284~~15,762	~~16,251~~15,818	~~-167~~-466
NYCA	~~32,246~~31,766	~~28,723~~28,990	~~31,398~~31,327	~~31,766~~31,650	~~-480~~-116

5.1.2 Load Forecast Uncertainty

As with all forecasting, uncertainty exists relative to forecasting NYCA loads for any given year. This uncertainty is incorporated in the base case model by using a load forecast probability distribution that is sensitive to different weather conditions. Recognizing the unique load forecast uncertainty (LFU) of individual NYCA areas, separate LFU models are prepared for five areas: New York City (Load Zone J), Long Island (Load Zone K), Westchester (Load Zones H and I), and two rest of New York State areas (Load Zones A-E and Load Zones F-G).

These LFU models are intended to measure the load response to weather at high peak producing temperatures. The LFU is based on the slope of load versus temperature, or the weather response of load. If the weather response of load increases, the slope of load versus temperature will increase, and the upper-bin LFU multipliers (Bins 1-3) will increase.

The LFU multipliers for the 2025-2026 IRM Study remained unchanged from the 2024-2025 IRM Study. ~~The new LFU multipliers include summer 2022 data, which was not included in prior LFU models. The response of Zones F-J to weather in 2022 was lower in magnitude than it was in previous hot summers, while the magnitude is great in Zones A-E, and Zone K. This change has resulted in lower LFU impacts on the IRM than previous years.~~ A sensitivity case shows that recognizing LFU in the ~~2024~~ 2025-2026 IRM Study has an effect of increasing IRM requirements by 5.1% (Table 7-1, Case 3), as compared to a range of ~~7.6~~5.1% to 9.1% in the previous five IRM studies. ~~Also, the new LFU model resulted in a 0.14% reduction in the IRM – see Table 6-1: Parametric IRM Impact Comparison – 2023 IRM Study vs. 2024 IRM Study.~~

5.1.3 Load Shape Model

The GE-MARS model allows for the representation of multiple load shapes. This feature has been utilized since the 2014-2015 IRM Study and was again utilized for the ~~2024~~ 2025-2026 IRM Study. This multiple load shape feature enables a different load shape to be assigned to each of seven load forecast uncertainty bins.

Starting with the 2023-2024 IRM Study, a combination of load shapes from the years 2013, 2017, and 2018 were selected by ICS as representative years, as recommended under the LFU Phase 2 Study.[9] The LFU Phase 2 Study recommended representing Bin 1 and 2 using the 2013 load shape, representing Bins 3 and 4 using the 2018 load shape, and representing Bins 5, 6, and 7 using the 2017 load shape. The recommendation to change representative load shapes was initially adopted in the base case of the 2023-2024 IRM Study and is also applied in the ~~2024~~ 2025-2026 IRM Study. ~~The 2024 study also adjusts the 2013, 2017, and 2018 load shapes to account for the expected 2024 BTM Solar penetration level.~~

During the 2025-2026 IRM study cycle, the NYISO developed a methodology of modeling behind-the-meter (BTM) solar explicitly as a supply resource in the IRM study. With the new modeling construct, it is possible to quantify the impact of evolving BTM solar resource in the system. BTM solar is not modeled as a supply resource in the 2025-2026 IRM study base case. 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 from the projected 2025-2026 BTM solar capacity.

The NYISO is working on developing an enhanced load adjustment methodology reflecting seasonal peak load forecasts and annual energy demand, model-based synthetic load shapes reflecting expected load patterns, as well as dynamic winter LFU development, ~~and BTM Solar modeling improvement,~~ with the goal of implementing these refinements in future IRM studies.

5.2 The Capacity Model

5.2.1 Conventional Resources: Planned New Capacity, Retirements, Deactivations, and Behind the Meter Generation

Planned conventional generation facilities that are represented in the ~~2024~~ 2025-2026 IRM Study are shown in Appendix A, Section A.3. The rating for each existing and planned resource facility in the capacity model is based on its Dependable Maximum Net Capability (DMNC). In circumstances where the ability to deliver power to the grid is restricted, the value of the resource is limited to its Capacity Resource Interconnection Service (CRIS) value. The source of

[9] https://www.nysrc.org/wp-content/uploads/2023/05/A.I.10-LDC_Recommendation_ICS4098.pdf

DMNC ratings for existing facilities is seasonal tests required by procedures in the NYISO Installed Capacity Manual.

There are no new thermal/conventional units planned in the ~~2024~~ 2025 IRM study, however, three units (New Athens Units 1, 2 and 3) were awarded additional CRIS (totally 47 MW) compared to what is recorded in the 2024 Gold Book. ~~One wind unit (*i.e.*, Western New York Wind Power) was previously modeled at 0 MW and is retired in study period for the 2024 IRM Study. No additional retirement is projected in the 2024 IRM Study compared to the assumptions for the 2023 IRM Study. However, a number of units that were previously anticipated to deactivate due to the May 1, 2023 requirements of the New York State Department of Environmental Conservation (DEC) regulations limiting NOx emissions for simple cycle turbines (Peaker Rule) have confirmed their intent to continue their operations beyond June 2024. These units, totaling 140.1 MW, were removed from the 2023 IRM Study, but have been reinstated in the 2024 IRM Study.~~ There are six projected retirements totaling 165.4 MW for the 2025-2026 Capability Year. Four of the six units were previously removed in the 2023-2024 IRM Study under the New York State Department of Environmental Conservation ("DEC") regulation to limit NOx emissions from simple cycle combustion turbines ("the Peaker Rules") but reinstated back in the 2024-2025 IRM study after confirming their intent to continue operations beyond June 2024. These units are modeled as retired for the 2025-2026 IRM Study.

A behind-the-meter-net-generation (BTM:NG) program resource, for the purpose of this study, contributes its full capacity while its entire host load is exposed to the electric system. Several BTM:NG resources with a total resource capacity of ~~387.1~~367.3 MW and a total host load of ~~148.8~~170.6 MW, are included in this ~~2024~~ 2025-2026 IRM Study. The full resource capacity of these BTM:NG facilities is included in the NYCA capacity model, while their host loads are included in the NYCA ~~2024~~ 2025 summer peak load forecast used for this study.

The NYISO has identified several state and federal environmental regulatory programs that could potentially impact operation of NYS Bulk Power System. The NYISO's analysis concluded that these environmental initiatives would not result in NYCA capacity reductions or retirements that would impact IRM requirements during the summer of ~~2024~~2025. The analysis further identified those regulations that could potentially limit the availability of existing resources, and those that will require the addition of new non-emitting resources. For more details, see Appendix C.

5.2.2 Renewable Resources

Intermittent types of renewable resources, including wind and solar resources, are becoming an increasing component of the NYCA generation mix. These intermittent resources are included in the GE-MARS capacity model as described below. These resources, plus the existing ~~4,750~~4,717 MW of hydro facilities, will account for a total of ~~7,660~~8,881 MW of NYCA renewable resources represented in the ~~2024~~ 2025-2026 IRM Study.

It is projected that during the ~~2024~~ 2025 summer period there will be a total wind capacity of ~~2,502.3~~2,566.2 MW participating in the capacity market in New York State. There were no new wind units included for the 2025-2026 IRM study.~~This represents an increase in available wind resources of 136 MW and reflects the addition of two new offshore wind resources.~~

GE-MARS allows the input of multiple years of wind data. This multiple wind shape model randomly draws wind shapes from historical wind production data. The ~~2024~~ 2025-2026 IRM Study used available wind production data covering the years ~~2018~~ 2019 through ~~2022~~2023. For any new wind facilities, zonal hourly wind shape averages or the wind shapes of nearby wind units will be modeled. As the offshore wind resources are new to the NYCA system, ~~no historical production data is available. T~~the NYISO retained a consultant to develop synthesized historical offshore wind production profiles[10] based on the historical weather conditions in the areas along New York's shoreline where offshore wind development is expected. These synthesized production profiles covered the period between 2000-2021. The ~~new~~ offshore wind resources in the ~~2024~~ 2025-2026 IRM Study are modeled using the synthesized offshore wind production profiles for 2017 through 2021. In order to capture the weather correlation between the offshore wind and the rest of the intermittent resources in GE-MARS simulation, the ~~2018-2021~~ 2019-2021 offshore profiles are grouped with the same period as other intermittent resources, ~~and~~ the 2017 offshore profile is grouped with the 2022 intermittent profiles, and the 2018 offshore profile is grouped with the 2023 intermittent profiles.

Overall, inclusion of the projected ~~2,502.3~~ 2,566.2 MW of wind capacity in the ~~2024~~ 2025-2026 IRM Study accounts for ~~7.2~~6.6% of the ~~2024~~ 2025-2026 IRM requirement (Table 7-1, Case 4). This relatively high IRM impact is a direct result of the wind facilities low-capacity factor during the summer peak period. The impact of wind capacity on unforced capacity is discussed in

[10] Offshore Production Profiles: https://www.nyiso.com/documents/20142/36079056/4%20NYISO_OffshoreWind_Hourly_NetCapacityFactor.xlsx/dc15cb6a-b6fc-6a6a-e1d0-467d5c964079

Appendix C.3, "Wind Resource Impact on the NYCA IRM and UCAP Markets." For wind units, a detailed summary of existing and planned wind resources is shown in Appendix A, Table A.9.

Land Fill Gas (LFG) units account for ~~103.3~~102.2 MW.

For the ~~2024~~ 2025-2026 IRM ~~S~~study, ~~90~~ 267 MW of utility level solar generation additions are included. The total New York State bulk power system (BPS) solar capacity in the ~~2024~~ 2025-2026 IRM Study is ~~304.4~~571.4 MW. Actual hourly solar plant output over the ~~2018-2022~~2019-2023 period is used to represent the solar shape for existing units, while new solar units are represented by zonal hourly averages or nearby units.

5.2.3 Energy Limited Resources

Based on the FERC approved NYISO tariff, Energy Limited Resources (ELR) units started to participate in the NYISO markets in 2021. The NYISO and GE developed the dynamic ELR functionality within the GE-MARS program and the recommended TC4C configuration in the ELR Whitepaper.[11] The recommended modeling would reduce the IRM and lower the Special Case Resource (SCR) program activation as compared to a fixed output profile modeling approach, and it was adopted in the Final Base Case in the 2023-2024 IRM Study. The TC4C configuration contains a static time period limitation for the output from the ELR units. Starting with the 2024-2025 IRM Study, a process is recommended to update the time period of the output limitation on an annual basis, based on the beginning of the 90% LOLE risk period from previous year's ~~IRM Final Base Case (FBC)~~ Locational Minimum Installed Capaciy Requirement (LCR) Study. In the ~~2024~~ 2025-2026 IRM Study, output from the ELRs will be available starting Hour Beginning 14, which is the beginning of the 90% LOLE risk window from the ~~2023~~ 2024-2025 LCR Study~~IRM FBC~~. This process aims to keep the ELR output limitation in close proximity to the period with the highest LOLE risk and the annual update process could have, if any, a small reduction on the IRM on a year-over-year basis.

5.2.4 Generating Unit Availability

Generating unit forced and partial outages are modeled in GE-MARS by inputting a multistate outage model that represents an equivalent demand forced outage rate (EFORd) for each unit represented. Outage data used to determine the EFORd is received by the NYISO from generator owners based on outage data reporting requirements established by the NYISO.

[11] The ELR Whitepaper can be found on the NYSRC website https://www.nysrc.org/wp-content/uploads/2023/03/ELR-Modeling-White-Paper-May-2021-FINAL.pdf

Capacity unavailability is modeled by considering the average forced and partial outages for each generating unit that have occurred over the most recent five-year time period. The time span considered for the ~~2024~~ 2025-2026 IRM Study covered the ~~2018-2022~~2019-2023 period.

~~The weighted average five-year EFORd calculated for generating units in Zones A-I, and Zone K for the 2018-22 period is higher than in the 2017-2021 period, which were used in the 2023 IRM Study. The overall NYCA wide weighted average EFORd in the 2024 IRM Study is therefore higher than the 2023 IRM Study, and the increase in average forced outage rates raises the IRM by 0.3% (Table 6-1). Appendix A, Figure A.5 depicts NYCA and Zonal five-year average EFORd trends from 2015 through 2022.~~ The weighted average five-year EFORd calculated for generating units in Load Zones A-F is higher while Load Zones G-J, J and K is lower than the 2018-2022 period, which were used in the 2024-2025 IRM Study. The overall NYCA wide weighted average EFORd in the 2025-2026 IRM Study is higher than the 2024-2025 IRM Study. Appendix A, Figure A.5 depicts NYCA and zonal five-year average EFORd trends from 2016-2023.

5.2.5 Emergency Operating Procedures (EOPs)

~~In the 2022 IRM Study, the need for SCRs was reduced to 38 days (probabilistic expected value) by redistributing the operating reserves and removing maintenance outside of the summer season. In the 2023 IRM Study, the need for SCRs was further reduced to 6.9 days, due to the increased West Central Reverse Limit from 1,600 MW to 2,275 MW based on the updated Summer 2022 Operating Study. The increased limit substantially reduced the need for SCR activation as more MW can flow from the rest of the NYCA into Zone A and B where most of the SCRs activations were triggered. In the 2024 IRM Study, the need for SCR resources has a slight increase to 8.1 days compared to the 2023 IRM Study, driven by the updated allocation of operating reserves, due to the in-service of the AC Transmission project upgrades.~~

As part of the Preliminary Base Case (PBC) for the 2025-2026 IRM Study, a new "Enhanced SCR Modeling"[12] technique was adopted for Special Case Resources. This decreased the IRM by 0.57%. For the 2025-2026 IRM Study, limitations are implemented for certain EOP steps. Specifically, EOP calls for Voluntary Curtailments and Public Appeals for the 2025-2026 IRM Study are limited to 3 calls per year which increased the IRM by 1.02%.

[12] Enhanced SCR Modeling

(1) Special Case Resources (SCRs)

SCRs are loads capable of being interrupted and distributed generators that are rated at 100 kW or higher. SCRs are ICAP resources that provide load curtailment only when activated when as needed in accordance with NYISO emergency operating procedures. GE-MARS represents SCRs as an EOP step, which is activated to avoid or to minimize expected loss of load. SCRs are modeled with monthly values based on July ~~2023~~ 2024 registration data. For the month of July, the forecast SCR value for the ~~2024~~ 2025-2026 IRM Study base case assumes that ~~1,281~~1,487 MW will be registered, with varying amounts during other months based on historical experience. This is ~~56~~ 206 MW higher than that assumed for the ~~2023~~ 2024-2025 IRM Study.

The new "Enhanced SCR Modeling" that was adopted into the PBC of the 2025-2026 IRM Study models SCRs as Energy Limited resources, using the GE-MARS EL3 unit type. SCRs are modeled as zonal duration limited resources with hourly response rates, subject to a 1 call per day limit. SCRs continue to be deployed as the first EOP step but are not subject to an annual or monthly limit to the maximum number of activations. Performance factors are captured in the hourly response rates rather than in setting the maximum modeled capacities.

~~The number of SCR calls for the 2024 IRM base case was limited to five calls per month.~~

~~The SCR performance model is based on discounting registered SCR values to reflect historical availability.~~ The SCR model used for the ~~2024~~ 2025-2026 IRM Study is based on a recent analysis of performance data for the 2012-2023~~2~~ period. ~~This analysis determined a SCR overall performance factor of 70.0%. This is 0.1% higher than the performance factor used in the 2023 IRM Study (refer to Appendix A, Section A.3.8 for more details). All areas saw an increase in participation level, but the performance factor decreased for Zones A-F and Zones G-I, and therefore the updated SCR model had a minor impact on system reliability.~~ Incorporation of "Enhanced SCR Modeling" decreased the IRM by 0.57% (Table 6-1) while the incorporation of the SCR~~s~~ enrollments in the NYCA capacity model has the effect of increasing the IRM by ~~3.1~~2.4% (Table 7-1, Case 5). ~~This increase results from the lower overall availability of SCR compared to the average statewide resource fleet availability.~~

(2) Other Emergency Operating Procedures

In addition to SCRs, the NYISO will implement several other types of EOP steps, such as voltage reductions, as required, to avoid or minimize customer disconnections. Projected ~~2024~~ 2025-2026 EOP capacity values are based on recent actual data and NYISO forecasts.

~~For the 2024 IRM Study, the NYISO implemented an additional set of topology limits to constrain emergency assistance in the IRM simulation during severe and extreme conditions.~~

~~The limit has been updated to vary by LFU bin. The recommendation from the NYISO considered the extra reserves that are available in the external control areas, and the areas' required reserve by load level (see section 5.4).~~

~~The NYISO also implemented the modeling change to maintain 400 MW of 10-min operating reserve during any load shedding event. This modeling change reflects the need to protect the bulk power system against volatility during emergency operation at the time of load shedding.~~

The 2025-2026 IRM Study implements a 3 call per year limit for Voluntary Curtailments and Public Appeals. This increased the IRM by 1.02% (Table 6-1). The 2025-2026 IRM Study also implemented dynamic emergency assistance interface group limits which apply bin specific limits for the external areas (see Attachment E5 from the 2025-2026 IRM FBC Assumptions Matrix).

Refer to Appendix B, Table B.2 for projected EOP frequencies for the ~~2024~~ 2025 Capability Year assuming the ~~23.1~~24.4% base case IRM.

5.2.6 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 when coupled with a non-locational ICAP Supplier. The owners of the UDRs annually elect whether they will utilize their capacity deliverability rights. This decision determines how UDR transfer capability will be represented in the 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 202~~4~~5-2026 IRM Study as having UDR capacity rights: LIPA's 330 MW High Voltage Direct Current (HVDC) Cross Sound Cable (CSC), LIPA's 660 MW HVDC Neptune Cable,~~[13]~~ and the 315 MW Linden Variable Frequency Transformer (VFT). 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 2025~~4~~-2026 IRM Study incorporates the confidential elections that these facility owners made for the 2025~~4~~-2026 Capability Year. The Hudson Transmission Partners 660 MW HVDC Cable (HTP) has been granted UDR rights but has

~~[13] *See* footnote 3 page 3~~

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lost its right to import capacity and therefore is modeled as being fully available to support emergency assistance.

UDRs, along with other cables captured in the IRM study, are modeled with outage rates based on their historical ~~average~~ performance. In prior IRM studies, the most recent 5-year period was used in this process. Following an NYSRC recommendation, a switch to using the most recent 10-year period was implemented in the 2025-2026 IRM Study. Therefore, i~~of their past 5-year's history. I~~n the 2025-2026~~4~~ IRM Study, the cable performance for 2014~~8~~-2023~~2~~ was~~is~~ used to develop the cable outage rate assumptions. The a~~A~~ggregated cable outage rate, which ~~is~~ covers the facilities of CSC, Neptune, VFT, HTP, Dunwoodie South, Y49/Y50, Norwalk Northport, A Line, and Jamaica Ties, decreased~~reduced~~ slightly from 5.36~~7~~%[14] to 5.31~~4.5~~% for the 202~~4~~5-2026 IRM Study compared to the 2024-2025 IRM Study~~and the aggregated statistics cover the facilities of CSC, Neptune, VFT, HTP, Dunwoodie South, Y49/Y50, Norwalk Northport, A Line, and Jamaica Ties~~.

5.3 The Transmission Model[15]

A detailed NYCA transmission system model is represented in the GE-MARS topology. The transmission system topology which includes eleven NYCA zones and four Outside World Areas, along with relevant transfer limits, is depicted in Appendix A, Figure A-10. The transfer limits employed for the ~~2024~~2025-2026 IRM Study were developed from emergency transfer limit analysis included in various studies performed by the NYISO, and from input from Transmission Owners and neighboring regions. The transfer limits are further refined by additional assessments conducted for this 2025-2026 IRM Study topology.

The transmission model assumptions included in the ~~2024~~2025-2026 IRM Study are listed in Table A.10 in the Appendix which reflects changes from the model used for the ~~2023~~2024-2025 IRM Study. These topology changes are as follows:

~~***In service of Segment B of AC Transmission Project, but with delay in the construction of Dover PAR***~~

14 Based on 5-year historical period from 2018-2022

15 The transmission model is discussed in Appendix A Section 3.5

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- ~~Central East voltage collapse limit increases from 2,654 MW to 3,885 MW; dynamic limits are also increased by the similar amount.~~
- ~~Central East + Marcy Group limit is increased from 4,260 MW to 5,590 MW; dynamic limits are also increased by similar amount.~~
- ~~UPNY-ConED limit increases from 6,675 MW to 7,050 MW.~~
- ~~UPNY/SENY limit increases from ,5250 MW to 7,150 MW and dynamic limits are removed. However, due to the delay of the construction of Dover phase angle regulator (PAR), the limit is expected to be lower than 7,150 MW. The NYISO was not able to complete its evaluation of the impact on the UPNY/SENY transfer limit from the Dover PAR delay. The NYISO did test various scenarios of the UPNY/SENY transfer limit reduction on the preliminary base case and concluded that the transfer limit reduction on UPNY/SENY from the Dover PAR delay is not expected to impact the 2024 IRM Study results. Consequently, the resource adequacy modeling was performed using an UPNY/SENY limit that is consistent with the Dover PAR operating.~~

Update to Central East Forward Limit due to Marcy STATCOM outage

- The Central East voltage collapse limit was reduced~~s~~ from 3,885 MW to 3,810 MW; each dynamic limit is also reduced by 75 MW~~s pertaining not this outage in the system~~. The updated transfer limits for Central East have been adopted from the Central-East Voltage Limit Study (CEVC 2024).
- The Central_East + Marcy South Group (Total East interface) is not impacted by the STATCOM outage because it is thermally constrained.

~~Update to Dysinger East and Zone A Group Limits~~

- ~~Dysinger East limit decreased from 2,200 MW to 2,100 MW.~~
- ~~Zone A group limit decreased from 2,650 MW to 2,500 MW.~~

Update to West Central Reverse Limit

- The West Central reverse limit was reduced~~s~~ from 2,275 MW to 2,200 MW. This update is driven by changes in load patterns in ~~Western New York (~~Load Zone A~~)~~ and ~~Genesee area (~~Load Zone B~~)~~.

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~~Update to various Zone K Transfer Limits:~~

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

Update to Dynamic Limits from Staten Island to Load Zone J (New York City):

- Dynamic limit updates from Con Edison's 2023 Local Transmission Plan (LTP) increased export capability from Staten Island to Load Zone J by 200-250 MW ~~when capacity unbottling projects are operational.~~depending on the operating status of certain generation facilities.
- The base export limit from Staten Island to Load Zone J remains 815 MW~~, but the dynamic updates offer more flexibility in managing exports under specific conditions, aligned with the Reliability Needs Assessment (RNA)~~.

Forced transmission outages based on historical performance are represented 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 historic failure rates and the time to repair. Transition rates into the different operating states for each interface were calculated based on the circuits comprising each interface, including failure rates and repair times for the individual cables, and for any transformer and/or phase angle regulator associated with that cable.

The applicable Transmission Owners~~ (TOs)~~ provided updated transition rates for their associated cable interfaces. Updated cable outage rates assumed in the ~~2024~~ 2025-2026 IRM Study resulted in no impact to ~~a 0.6% increase in~~ the IRM compared with the ~~2023~~2024-2025 IRM Study (Table 6-1). In the 2024-2025 IRM Study, cable outage rates were based on the annualized average of the past 5 years of historical data. However, the 2025-2026 IRM Study adopts a new methodology, using the annualized average over the past 10 years. This change smooths the impact of tail events or years with unusually long cable outages, ensuring more stable and reliable estimates. Additionally, the 10-year average better captures long-term

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As in all previous IRM studies, forced outage rates for overhead transmission lines were not represented in the ~~2024~~ 2025-2026 IRM Study. Historical overhead transmission availability was evaluated in a study conducted by ICS in 2015, *Evaluation of the Representation of Overhead Transmission Outages in IRM Studies*, which concluded that representing overhead transmission outages in IRM studies would have no material impact on the IRM (see www.nysrc.org/reports).

The impact of NYCA transmission constraints on NYCA IRM requirements depends on the level of resource capacity in any of the downstream zones from a constraining interface, especially in New York City (Load Zone J) and Long Island (Load Zone K). To illustrate the impact of transmission constraints on the IRM, if internal NYCA transmission constraints were eliminated, the required ~~2024~~ 2025-2026 IRM could decrease by ~~2%~~ 1.85% (Table 7-1, Case 2).

The ~~2024~~ 2025-2026 IRM Study ~~included a~~ modeled~~ing~~ ~~change to~~ limits to emergency assistance from neighboring jurisdictions during severe and extreme conditions by implementing additional topology limitations between each of the external areas and NYCA. Such topology limitations do not reflect the real constraints on the transmission system, but rather, represent an estimate of the neighboring area's ability to provide support to the NYCA at EOP steps during the GE-MARS simulation. More details on this modeling ~~change~~ are discussed in section ~~5.2.5~~5.4.

5.4 The Outside World Model

The Outside World Model consists of four interconnected Outside World Areas contiguous with NYCA: Ontario, Quebec, New England, and the PJM Interconnection (PJM). NYCA reliability is improved and IRM requirements can be reduced by recognizing available emergency assistance (EA) from these neighboring interconnected control areas, in accordance with control area agreements governing emergency operating conditions.

For the ~~2024~~ 2025-2026 IRM Study, two Outside World Areas, New England and PJM, are each represented as multi-area models—*i.e.,* 14 zones for New England and five zones for ~~the~~ PJM ~~Interconnection~~. Another consideration for developing models for the four Outside World Areas is to recognize internal transmission constraints within those areas that may limit EA into the NYCA. This recognition is explicitly considered through direct multi-area modeling of well-defined Outside World Area "bubbles" and their internal interface constraints. The model's representation explicitly requires adequate data in order to accurately model transmission interfaces, load areas, resource and demand balances, load shapes, and coincidence of peaks, among the load zones within these Outside World Areas.

In 2019, the ICS conducted an analysis[16] of the IRM study's Outside World Area Model to review its compliance with a NYSRC Policy 5 objective that "interconnected Outside World Areas shall be modeled to avoid NYCA's overdependence on Outside World Areas for emergency assistance.". This analysis resulted in a change in the methodology to scale loads proportional to excess capacities in each ~~load~~ zone of each Outside World Area to meet the LOLE criterion and the Control Area's minimum IRM requirement, as well as the implementation of global EA limit of 3,500 MW. For the past IRM studies, EA assumptions have reduced IRM requirements by approximately ~~6.2~~5.5% (Table 7-1, Case 1).

For the 2024-2025 IRM Study, an EOP whitepaper[17] was conducted and the whitepaper concluded that further refinement of the previous EA assumptions would improve the reasonableness of expectations for availability of EA. Additional topology limits to constraint EA by LFU bin in the IRM study were recommended. In the 2024-2025 IRM Study, the ~~3,500 MW~~static EA limit was modified as follows: LFU Bin 1: 1,470 MW; LFU Bin 2: 2,600 MW; LFU Bin 3-7: 3,500 MW. These limits were also implemented on each of the external Control Areas, based on historical extra reserves available in these Control Areas during NYCA peak load periods to better reflect potential support that external Control Areas can provide when New York is in need. ~~Utilizing these new limits for the 2024 IRM Study increases the IRM by 2% (Table 7-1, Case 6a). These EA limits will be reviewed and updated on an annual basis including updated extra reserves data from the external Control Areas.~~ For the 2025-2026 IRM Study, the dynamic emergency assistance modeling was expanded to include the HVDC lines to reflect the proportional limits to emergency assistance from the external control areas.

5.5 Database Quality Assurance Review

It is critical that the database used for IRM studies undergo sufficient review in order to verify its accuracy. The NYISO, GE, and two ~~New York~~ Transmission Owners conducted independent data quality assurance reviews after the preliminary base case assumptions were developed and prior to preparation of the final base case. Masked and encrypted input data was provided

[16] *See Evaluation of External Area Modeling in NYCA IRM Studies*, for a description of this analysis, at http://www.nysrc.org/reports3.html

[17] EOP Whitepaper: https://www.nysrc.org/wp-content/uploads/2023/10/EOP-Review-Whitepaper-Report_FINAL_For_Posting.pdf

by the NYISO to the two Transmission Owners for their review. Also, certain confidential data ~~are~~ is reviewed by two of the NYSRC consultants as required.

The NYISO, GE, and Transmission Owner reviews found minor errors within the assumptions matrix for the 2025-2026 IRM Study preliminary base case, which were subsequently corrected. ~~with the data in the preliminary base case, which were corrected.~~ A summary of these quality assurance reviews for the ~~2024~~ 2025-2026 IRM Study input data is shown in Appendix A, Section A.4.

6. Parametric Comparison with ~~2023~~ 2024-2025 IRM Study Results

The results of this ~~2024~~ 2025-2026 IRM Study of 24.4% show that the final base case IRM result represents a ~~3.2~~1.3% increase from the ~~2023~~ 2024-2025 IRM Study base case value of 23.1%. Note, the final approved IRM value for the 2024 Capability Year was only 22.0%.~~, however the analysis Final Base Case results from the previous year.~~ Table 6-1 compares the estimated IRM impacts of updating several key study assumptions and revising models from those used in last year's study. The estimated percentage IRM change for each parameter was calculated from the results of a parametric analysis in which a series of IRM sensitivity runs were conducted to update the underlying IRM model data and test the IRM impact of individual parameters. In practice, the parametric analysis is conducted in a sequential manner and the parametric results can be largely affected by the study sequence and the selected parametric adjustment method. -The total parametric change on the IRM is over 2.~~8~~9%, while the final Tan-45 analysis shows that there is only a 1.3% increase from last year's Final Base Case.~~Therefore, some of the IRM impacts shown in Table 6-1 reflect the impacts from separate Tan 45 analysis, while some represent the results from parametric analysis. The use of different analyses aims to provide a realistic representation of the IRM impact from each parameter. Some of the individual IRM impacts are also adjusted such that the net sum of the -/+ % parameter changes add up to the 3.2% IRM increase from the 2023 IRM Study.~~ Table 6-1 also provides the reason for the IRM change for ~~each~~ some of the study parameters from the ~~2023~~ 2024-2025 IRM Study.

There are ~~eleven~~ fourteen parameter drivers that in combination *increased* the ~~2024~~ 2025-2026 IRM from the ~~2023~~ 2024 base case IRM by 4.~~89~~354%. Of these ~~eleven~~ fourteen drivers, the most significant was the ~~reduction in EA import limits in the higher load bins~~limit on EOP calls which increased the IRM by ~~2.24~~1.02%. The next three most significant are the ~~change in cable transition rates~~addition of the new renewable generators which increased the IRM by 0.~~59~~63%, the ~~increase~~ change in ~~thermal outage rate~~SCR capacities which increased the IRM by 0.~~43~~53% and the ~~addition of 90 MW of solar generation~~change in generator ratings which increased the IRM by 0.~~34~~41%. ~~This was followed by the change in topology associated with the AC Transmission project upgrades and the withholding of an~~

~~additional 50 MW of Operating Reserves at load shedding which both increased the IRM by 0.25%. Bringing back the Peakers which had been assumed for deactivation increased the IRM by 0.23% and the addition of 136 MW of offshore wind units which increased the IRM by 0.19%. Updates in the treatment of the SCRs increased the IRM by 0.14%. The change in run-of-river hydro generation shapes caused a 0.13% increase. Lower DMNC ratings in the downstate areas increased the IRM by 0.1%.~~ The remaining changes had relatively minor changes in the IRM.

Seven parameter drivers in combination *decreased* the IRM from the ~~2022~~ 2024 base case by 1.~~59~~49%. Of these seven drivers, the most significant was the ~~expected increase in the amount of BTM Solar~~ change in the SCR modeling ~~generation~~ which decreased the IRM by 0.57%. ~~Modifications in the External Areas and the subsequent Policy 5 adjustments resulted in a 0.37% decrease in IRM. Changes in the 2023 Load Forecasts (including the 2024 Fall Load Forecast), which resulted in a slight peak load increase across the system, resulted in a 0.20% reduction in the IRM. The LFU model was adjusted slightly and resulted in a 0.14% IRM reduction. Shifting the Wind shapes forward by a year resulted in a 0.11% decrease in IRM. A slight increase in the value of the voltage reductions reduced the IRM by 0.11%.~~ All other modifications had less than a 0.3% impact.

The parameters in Table 6-1 are discussed under *Models and Key Input Assumptions.*

Table 6-1 Parametric IRM Impact Comparison 2023-2024

Description	Impact on Margins				Reason for change
-	NYCA	NYC	LI	LHV	
IRM 2023 Final Base Case	19.9	78.2	107.4	88.5	
-	-	-	-	-	
Reduce Emergency Assistance limits per EOP Whitepaper recommendations *	2.24	-0.30	-0.40	-4.50	Reduction of EA limits in higher load bins increases IRM
Cable Transition Rate *	0.59	-2.99	0.42	-2.19	Average rate decreased but locational impacts increased IRM.
Thermal Outage Rate (2018-2022)	0.43	0.44	0.24	0.46	
New Generators (Solar)	0.34	0.00	0.00	0.00	Renewables have lower availability than thermal units.
AC Transmission Topology *	0.25	-1.27	-0.83	-0.93	New transmission shifted Tan 45 curve down and increased IRM.
Withholding Operating Reserves	0.25	0.18	0.25	0.19	Increase in operating reserves withheld in EOP step.
2023 Peaker Rule Non-Deactivations	0.23	-0.44	2.18	-0.17	Peakers have a higher EFORd than the average unit.
New Generators (Offshore Wind)	0.19	-0.55	3.00	-0.59	Renewables have lower availability than thermal units.
SCR Update	0.14	0.19	0.00	0.17	
RoR Shapes (2018-2022)	0.13	0.09	0.13	0.10	
2023 Gold Book DMNC Updates	0.10	0.42	-1.45	0.14	
Sum of IRM Increases	4.89	-4.24	3.55	-7.33	
BTM Solar Load Shape Adjustment	-0.50	-0.36	-0.52	-0.39	
External Data + Policy 5 Adjustment	-0.37	-0.21	-0.38	-0.29	
2023 Load Forecast	-0.20	0.31	1.32	0.29	
ELR Update	-0.16	-0.12	-0.17	-0.12	
Load Forecast Uncertainty	-0.14	-0.10	-0.14	-0.10	
Wind Shapes (2018-2022)	-0.11	0.00	0.00	0.00	

~~EOP changes (Voltage Reduction)~~	~~-0.11~~	~~-0.08~~	~~-0.11~~	~~-0.09~~
~~* verified by Tan 45 analysis~~	-	-	-	-
~~Sum of IRM Decreases~~	~~-1.59~~	~~-0.55~~	~~0.01~~	~~-0.70~~
-	-	-	-	-
~~Non Material Changes~~	~~0.01~~	~~0.65~~	~~-0.27~~	~~0.34~~
-	-	-	-	-
~~Preliminary Base Case Parametric Results **~~	~~23.21~~	~~74.06~~	~~110.69~~	~~80.85~~
~~Actual Tan 45 Results~~	~~23.100~~	~~72.730~~	~~103.207~~	~~84.577~~
~~delta~~	~~-0.110~~	~~-1.326~~	~~-7.479~~	~~3.723~~

~~Non-Material Changes (Less than 0.05% delta on IRM)~~				
~~Description~~	~~Impact on Margins~~			
-	~~NYCA~~	~~NYC~~	~~LI~~	~~LHV~~
-	-	-	-	-
~~Database check~~	~~0.00~~	~~0.00~~	~~0.00~~	~~0.00~~
~~LFG Shapes (2018-2022)~~	~~0.00~~	~~0.00~~	~~0.00~~	~~0.00~~
~~Solar Shapes (2018-2022)~~	~~-0.01~~	~~0.00~~	~~-0.02~~	~~0.00~~
~~MARS Version Update (4.13)~~	~~-0.03~~	~~-0.02~~	~~-0.03~~	~~-0.02~~
~~Internal Topology Update~~	~~0.02~~	~~0.02~~	~~0.03~~	~~0.02~~
~~BTM:NG~~	~~0.02~~	~~0.74~~	~~-0.27~~	~~0.48~~
~~Preliminary SCRs~~	~~0.00~~	~~0.00~~	~~0.00~~	~~0.00~~
~~South Cairo Retirement~~	~~-0.02~~	~~-0.01~~	~~0.07~~	~~-0.07~~
~~Miscellaneous Data Correction~~	~~-0.05~~	~~-0.10~~	~~-0.15~~	~~-0.11~~
~~EFORd Update~~	~~0.04~~	~~0.03~~	~~0.04~~	~~0.03~~
~~MARS Update Version 4.14.2179~~	~~0.00~~	~~0.00~~	~~0.00~~	~~0.00~~
~~EOP Order Update~~	~~0.00~~	~~0.00~~	~~0.00~~	~~0.00~~
~~EOP Operating Reserve Updated Allocation~~	~~0.03~~	~~0.02~~	~~0.03~~	~~0.02~~
~~DSM Production Shapes~~	~~-0.01~~	~~-0.01~~	~~-0.01~~	~~-0.01~~
~~Topology~~	~~0.02~~	~~0.02~~	~~0.02~~	~~0.02~~
~~Database Clean-up~~	~~-0.01~~	~~0.00~~	~~0.00~~	~~0.00~~
~~Removal of Kings Plaza~~	~~0.00~~	~~-0.04~~	~~0.02~~	~~-0.02~~
~~revised Policy 5 Adjustments~~	~~0.00~~	~~0.00~~	~~0.00~~	~~0.00~~
-	-	-	-	-
~~Sum of Non-Material Changes~~	~~0.01~~	~~0.65~~	~~-0.27~~	~~0.34~~

Table 6-1: 2024 vs 2025 Parametric Impact Comparison					
Parameter	**Impact on Margins**				**Reason for Change**
	IRM	**NYC**	**LI**	**G-J**	
2024-2025 IRM Final Base Case (FBC)	**23.100%**	**72.730%**	**103.207%**	**84.577%**	
Study Parameters that Increased the IRM					
NYSRC Recommendation: EOP Calls Limit	1.018%	1.381%	1.838%	1.507%	3 Call/Year Limit to Voluntary Curtailment and Public Appeals
New Generators	0.628%	0.000%	0.000%	0.000%	
SCR Capacities	0.531%	0.244%	-0.202%	0.191%	
Generator Capacities	0.413%	-0.711%	1.251%	-0.113%	
NYSRC Recommendation: PJM Dynamic Limits	0.339%	0.461%	0.613%	0.503%	Apply Dynamic Limits Across All PJM Interfaces
UDR Elections	0.314%	-0.406%	5.111%	-0.443%	
BTM:NG	0.309%	0.352%	-0.398%	0.383%	
EOP Updates	0.284%	0.200%	0.276%	0.216%	Update Voluntary Curtailment, Public Appeals, and Voltage Reduction Amounts
Load Updates	0.257%	0.669%	-0.511%	0.158%	
Cable Outage Rate Update	0.142%	0.191%	0.268%	0.208%	
Summer Maintenance	0.061%	0.083%	0.112%	0.091%	
Increased Replications	0.025%	0.018%	0.025%	0.019%	Increase to 4,250 Replications to Maintain Standard Error Criteria
PJM Western Ties Update	0.016%	0.011%	0.015%	0.012%	
Generator Deactivations	0.010%	0.350%	-1.340%	0.464%	

Study Parameters that Decreased the IRM					
Enhanced SCR Modeling	-0.570%	-0.403%	-0.543%	-0.438%	Adoption of Enhanced SCR Modeling
Topology Updates	-0.289%	-0.386%	-0.543%	-0.421%	Update to Dynamic Limits from Staten Island to Load Zone J
External Area Modeling	-0.252%	-0.177%	-0.235%	-0.193%	
NYSRC Recommendation: 10 Year Cable Outage Rates	-0.137%	-0.187%	-0.248%	-0.204%	Update from 5 Year to 10 Year Cable Outage Rates
Intermittent Resource Shapes Update	-0.123%	-0.110%	-0.155%	-0.119%	
Generator Outage Rate Update	-0.066%	-0.030%	-0.096%	-0.040%	
External Sales/Purchases	-0.054%	-0.035%	-0.047%	-0.038%	
Total Impact/Results					
Total Parametric Impact	**2.856%**	**1.515%**	**5.191%**	**1.743%**	
2025-2026 Parametric Results	**25.956%**	**74.245%**	**108.398%**	**86.320%**	
2025-2026 FBC Tan45 Results	**24.400%**	**75.581%**	**107.295%**	**86.912%**	Results of FBC Tan45
Tan45 Delta	**-1.556%**	**1.336%**	**-1.103%**	**0.592%**	Delta between the Parametric Results and the Tan45 Results

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7. Sensitivity Case Study

In addition to calculating the IRM using base case assumptions, sensitivity analyses are run as part of an IRM study to determine IRM outcomes using different assumptions than in the base case. Sensitivity studies provide a mechanism for illustrating "cause and effect" of how some performance and/or operating parameters and study assumptions can impact reliability. Certain sensitivity studies, termed "IRM impacts of base case assumption changes," serve to inform the NYSRC Executive Committee when determining the Final IRM regarding how the IRM may be affected by reasonable deviations from selected base cases assumptions. The methodology used to conduct sensitivity cases starts with the base case IRM results and adds or removes capacity from all NYCA zones until the NYCA LOLE approaches 0.1 Event-Days/year.

Table 7-1 shows the IRM requirements for the various sensitivity cases. Note, Case 0 was the original ~~Preliminary~~ Final Base Case. All of the sensitivity cases are relative to that. ~~Case 6a with the reduced EA from neighboring systems was then selected for the new base case and the resulting 23.1% IRM is what was reflected in Table 6-1. Because of the lengthy computer run time and personnel needed to perform a full Tan 45 analysis in IRM studies[18], 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.~~

In addition to showing the IRM requirements for various sensitivity cases, Table 7-1 shows the LOLH and EUE reliability metrics for each case[19]. 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[16]. 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 7-1 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.~~ These parameters and their IRM impacts are discussed in Sections 5.1.2 and 5.4, respectively.

Case 6a examines the impact of reduced ~~EA from neighboring systems based on the recommendations from the analysis in the EOP Whitepaper~~oil availability in the winter, reducing the oil capacity to 11,000 MW. Case 6b further reduced the winter ~~limits to zero~~oil availability to only 8,000 MW. ~~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 natural gas availability constraints.~~showed the impact of modeling Behind-the-Meter (BTM) solar resources explicitly. This modeling will allow better understanding of the impact of solar generation on the system. ~~Finally, Case 8 looked at the impact of the~~

~~[18] The Tan 45 method is described in Section 3.~~

[19] **LOLH**: 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: The expected amount of energy (MWh) during loss of load events that cannot be served each year.

~~delay on the installation of the Dover PAR. While some limits were affected the overall impact on the IRM was negligible.~~

~~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.~~[20]

In June 2023, the NYSRC issued a study, "Offshore Wind Data Review – NYSRC Preliminary Findings," raising concerns about the correlated availability and performance of offshore wind within the NYCA system and across the Northeast, particularly between New York and New England. In November 2024, NYISO conducted an updated analysis of offshore wind facilities in neighboring systems, which included the Vineyard Offshore Wind facility in New England. However, results concluded that offshore wind levels in both NYCA and New England are still too low to impact the IRM, limiting the ability to assess correlated impacts. Inconsistencies persist in this year's modeling approach for offshore wind and other intermittent resources in neighboring regions compared to NYCA's IRM methodology. Consequently, actions are being taken to urge the NPCC to establish consistent modeling assumptions across all interconnected systems, and the NYISO will collaborate with the NYSRC Extreme Weather Working Group to monitor system impacts as offshore wind capacity grows.

~~[20] https://www.nysrc.org/wp-content/uploads/2023/07/NYSRC-Wind-Impacts-Final-07_18_23.pdf~~

Table 7.1 - 2025-2026 Installed Reserve Margin (IRM) Study - Sensitivity Cases

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Case	Description	IRM (%)	NYC (%)	LI (%)	IRM (%) Change from Base	LOLH (hrs/yr)	EUE (MWh/yr)
0	2025-2026 IRM Final Base Case (FBC)	24.400	75.581	107.295	-	0.374	216.98
	These are the Base Case technical results derived from knee of the IRM-LCR curve						
1	NYCA Isolated	29.865	79.423	112.41	5.465	0.322	198.973
	Track Total New York Control Area (NYCA) Emergency Assistance (EA) – NYCA system is isolated and receives no emergency assistance from neighboring control areas (New England, Ontario, Quebec, and PJM). Unforced Capacity Deliverability Rights (UDRs) are allowed						
2	No Internal NYCA transmission constraints	22.547	74.278	105.56	-1.853	0.365	326.999
	Track level of NYCA congestion with respect to the IRM model – eliminates internal transmission constraints and measures the impact of transmission constraints on statewide IRM requirements						
3	No Load Forecast Uncertainty	19.349	72.03	102.567	-5.051	0.268	51.274
	Shows sensitivity of IRM to load uncertainty, if the forecast peak loads for NYCA have a 100% probability of occurring						
4	No Wind Capacity	17.771	76.601	105.96	-6.629	0.367	228.969

	Shows wind impact for both land-based and off-shore wind units and can be used to understand Equivalent Demand Forced Outage Rate (EFORd) sensitivity						
5	No SCR Capacity	22.050	72.818	108.166	-2.350	0.360	211.508
	Shows sensitivity of IRM to the Special Case Resource (SCR) program						

Case	Description	IRM (%)	NYC (%)	LI (%)	IRM (%) Change from Base	LOLH (hrs/yr)	EUE (MWh/yr)
6a	Gas Constraints (Tan45) 11,000 MW of oil modeled	25.300	76.195	107.5231	0.900	0.350	186.396
	Shows impact to reliability when winter capacity is reduced due to gas constraints and can be used to understand tightening winter conditions						
6b	Gas Constraints (Tan45) 8,000 MW of oil modeled	31.600	78.103	108.269	7.200	0.310	129.996
	Shows impact to reliability when winter capacity is reduced due to gas constraints and can be used to understand tightening winter conditions						
7	BTM Solar (Tan45)	25.446	76.479	108.916	1.046	0.397	242.431

	Shows the impact of modeling Behind-the-Meter (BTM) solar resources explicitly. The modeling can be used to understand the impact of evolving BTM solar penetration in the system.

Note: All results are calculated by adding/removing capacity from Load Zones A - K unless otherwise noted

~~Table 7-1 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 7-1 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)~~	~~0.36537~~	~~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.~~						

8. NYISO Implementation of the NYCA Capacity Requirement

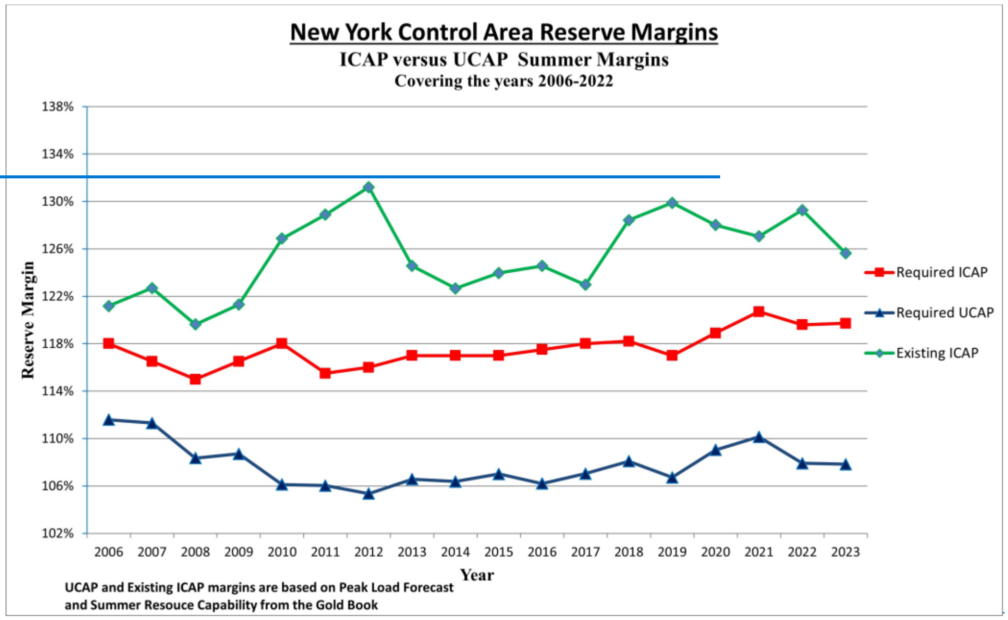
The NYISO values capacity sold and purchased in the market in a manner that considers the forced outage ratings of individual units, whereby generating unit capacity is derated to an unforced capacity basis recognizing the impact of historic unit forced outages. This derated capacity is referred to as "UCAP." In the NYCA, these translations occur twice during the course of each capability year, prior to the start of the summer and winter capability periods.

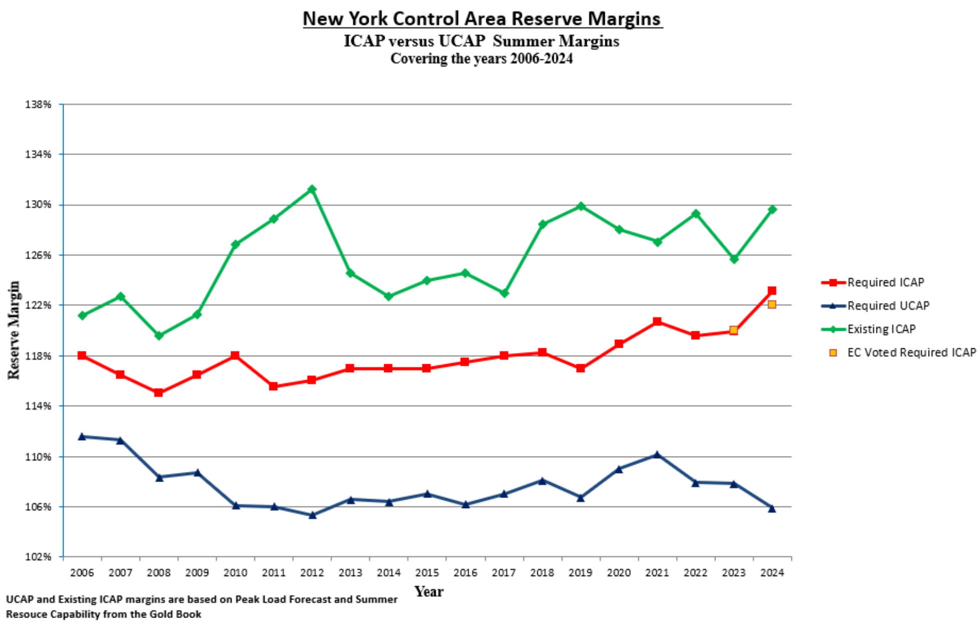
Additionally, the IRM and LCRs are translated into equivalent UCAP values during these periods. The conversion to UCAP essentially translates from one index to another; it is not a reduction of actual installed resources. Therefore, no degradation in reliability is expected. The NYISO employs a translation methodology that converts ICAP requirements to UCAP in a manner that ensures compliance with NYSRC Resource Adequacy Rule A.1: R1. The conversion to UCAP provides financial incentives to decrease the forced outage rates while improving reliability.

Due to lower contribution to reliability, the increase in wind resources lowers the translation factor from required ICAP to required UCAP which reflects the performance of all resources on the system. Figure 8.1 top of next page shows that required UCAP margins decrease slightly even though the required ICAP margins increase slightly. This is due to resources with below average performance being removed from the system and the required UCAP is a function of required ICAP and the weighted average availability of system resources. Overall, the *required* ICAP and UCAP remained roughly constant to last year although the *existing* ICAP decreased by about 4%.

Appendix D provides details of the ICAP to UCAP conversion.

Figure 8-1 NYCA Reserve Margins




New York Control Area Reserve Margins
ICAP versus UCAP Summer Margins
Covering the years 2006-2024
Reserve Margin
138%
134%
130%
126%
122%
118%
114%
110%
106%
102%
2006 2007 2008 2009 2010 2011 2012 2013 2014 2015 2016 2017 2018 2019 2020 2021 2022 2023 2024
Year
Required ICAP
Required UCAP
Existing ICAP
EC Voted Required ICAP
UCAP and Existing ICAP margins are based on Peak Load Forecast and Summer Resouce Capability from the Gold Book