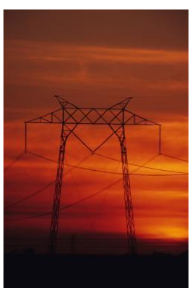
Technical Study Report

New York Control Area Installed Capacity Requirement



For the Period May 2023~~2~~ to April 2024~~3~~

December ~~10~~XX, 2022~~1~~

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 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, 2023~~2~~, through April 30, 2023~~3~~ (2023~~2~~ Capability Year). The IRM study described in this report for 2023~~2~~ Capability Year is referred to as the "2023~~2~~ IRM Study."

Results of the NYSRC technical study show that the required NYCA IRM for the 2023~~2~~ Capability Year is ~~19.6~~20.2% under base case conditions. This IRM satisfies the NYSRC and Northeast Power Coordinating Council (NPCC) reliability criterion of a Loss of Load Expectation (LOLE) of no greater than 0.1 days per year. The base case, along with other relevant factors, will be considered by the NYSRC Executive Committee on December 9~~3~~, 2022~~1~~ for its adoption of the Final NYCA IRM requirement for the 2023~~2~~ Capability Year.

The NYSRC study procedure used to establish the NYCA IRM[2] also produces corresponding "initial" New York City and Long Island locational capacity requirements (LCRs) necessary to satisfy the NYCA resource adequacy criterion. The 2023~~2~~ IRM Study determined initial LCRs of ~~80.7~~78.4% and ~~99.8~~108.0% for the New York City and Long Island localities, respectively. This represents a decrease of 2.3% for NYC and an increase of 8.2% in Long Island. In accordance with its responsibility of setting the LCRs, the New York Independent System Operator, Inc. (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 ~~19.6~~20.2% IRM base case value for the 2023~~2~~ Capability Year represents a *~~1.1~~0.6% ~~decrease~~ increase* from the 2022~~1~~ base case IRM of ~~20.7~~19.6%. Table 6-1 shows the IRM impacts of individual updated study parameters that result in this change. In summary:

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

[2] 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."

- There are ~~seven~~ seven parameter drivers that in combination *increased* the 2023~~2~~ IRM from the 2022~~1~~ base case IRM by ~~1.7~~3.8%. Of these ~~seven~~ seven drivers, the two most significant are the addition of ~~158~~ 539.3 MW of wind ~~and 183 MW of solar~~ units which increased the IRM by ~~0.6~~1.2% and the ~~partial outage of the Neptune UDR~~[3]withholding of 350 MW of Operating Reserve at load shedding which increased the IRM by ~~0.5~~1.1%. The change in UDR elections caused a 0.8% increase. ~~These~~ This ~~were~~ was followed by updates of the outside areas and Policy 5 adjustments ~~reduced availability of the subterranean cables surrounding New York City and Long Island~~ which increased the IRM by 0.3~~2~~%, and lower DMNC ratings in the downstate areas which increased the IRM by 0.2%.~~.~~ ~~Four~~ Two other factors are shown on table 6-1 and result in an additional 0.~~4~~2% increase in the IRM.
- ~~Seven~~ Six parameter drivers in combination decreased the IRM from the 2022~~1~~ base case by ~~2.8~~3.2%. Of these ~~seven~~ six drivers, the most significant was the Peaker deactivations in NYC which decreased the IRM by 0.9%. Updates to the ELR modeling, which increased their availability reduced the IRM by 0.8%. ~~are a~~The lowering of several of the high load bins of the updated Load Forecast Uncertainty model~~, which~~ also resulted in a ~~1.0~~0.6% IRM reduction. Topology updates, including restoration of Neptune decreased the IRM by 0.5% and ~~an updated load forecast, which resulted in a reduction of 0.7%. Five other factors are show on table 6-1 and resulted in a further combined reduction of 1.1%~~the new load shapes, which replaced 2002, 2006 and 2007 shapes with 2013, 2017 and 2018, reduced the IRM by an additional 0.3%. Finally, the update in the Run of River shapes reduced the IRM by an additional 0.1%

~~[3] The Neptune cable UDR transfer capability had been derated to 375 MW from 660 MW due to a transformer replacement required at Newbridge Rd BK1 and was initially scheduled to return to full capability on April 8th of 2022. On November 16, 2021 the outage was extended to July 15, 2022 and on November 30, 2021 it was extended to August 1, 2022. This announcement was well after the base case assumptions described above were approved and used for determining the 2022 initial base case IRM. The impact of the extended outage was then analyzed in a "Special Sensitivity Case" in accordance with Policy 5-15 and was approved as a base case assumption.~~

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 2023~~2~~. NYSRC Policy 5-15 describes the Executive Committee process for establishing the final IRM.

In addition, a confidence interval analysis was conducted to demonstrate that there is a high confidence that the base case ~~19.6~~20.2% IRM will fully meet NYSRC and NPCC resource adequacy criterion that require a Loss of Load Expectation (LOLE) of no greater than 0.1 days per year.

The 2023~~2~~ 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).

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, 2023~~2~~ through April 30, 2024~~3~~ (2023~~2~~ 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 2022 Capability Year.

The NYISO will implement the Final NYCA IRM as determined by the NYSRC, in accordance with the NYSRC Reliability Rules, NYSRC Policy 5-15, *Procedure for Establishing New York Control Area Installed Capacity Requirement and the Installed Reserve Margin (IRM);*[4] the NYISO Market Administration and Control Area Services Tariff; and the NYISO Installed Capacity (ICAP) Manual.[5] The NYISO translates the required IRM to a UCAP basis. These values are also used in a Spot Market Auction based on FERC-approved Demand Curves. The schedule for conducting the 2023~~2~~ IRM Study was based on meeting the NYISO's timetable for conducting this auction.

The study criteria, procedures, and types of assumptions used for the study for establishing the NYCA IRM for the 2023~~2~~ Capability Year (2023~~2~~ IRM Study) are set forth in NYSRC Policy 5-15. The primary reliability criterion used in the IRM study requires an LOLE of no greater than 0.1 days per 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 5-15 and discussed in detail later in this report.

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

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

The NYSRC procedure for determining the IRM also identifies "initial" corresponding locational capacity requirements (LCRs) 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 5-15 – is responsible for setting *final* LCRs for the New York City Long Island and Zones G-J Localities. For its determination of LCRs for the 2023~~2~~ Capability Year, the NYISO will continue utilizing an economic optimization methodology approved by the Federal Energy Regulatory Commission.

The 2023~~2~~ 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 2022~~1~~, can be found on the NYSRC website.[6] Appendix C, Table C.1 provides a record of previous NYCA base case and final IRMs for the 2000 through 2021 Capability Years. Figure 8-1 and Appendix C, Table C.2, show UCAP reserve margin trends over previous years. Definitions of certain terms in this report can be found in the Glossary (Appendix D).

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 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 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*

[6] http://www.nysrc.org/reports3.asp

average, no more than 0.1 day per 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 day in ten years or 0.1 day per 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 day per year has provided an acceptable level of reliability for many years.

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 2023~~2~~ IRM Study are described in detail in NYSRC Policy 5-15, *Procedure for Establishing New York Control Area Installed Capacity Requirements and the Installed Reserve Margin (IRM)*. Policy 5-15 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 days per year of expected resource capacity shortages.

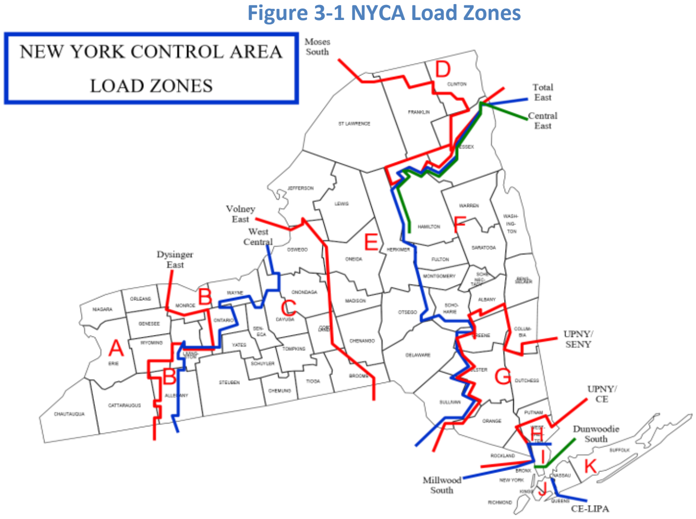
General Electric's Multi-Area Reliability Simulation (GE-MARS) is the primary computer program used for this probabilistic analysis. This program includes detailed load, generation, and transmission representation for eleven NYCA load zones — plus four Outside World Control Areas (Outside World Areas) 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 days per 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 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 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 IRM Study and all later studies, including this 2023~~2~~ IRM Study, were simulated using all hours in the year.

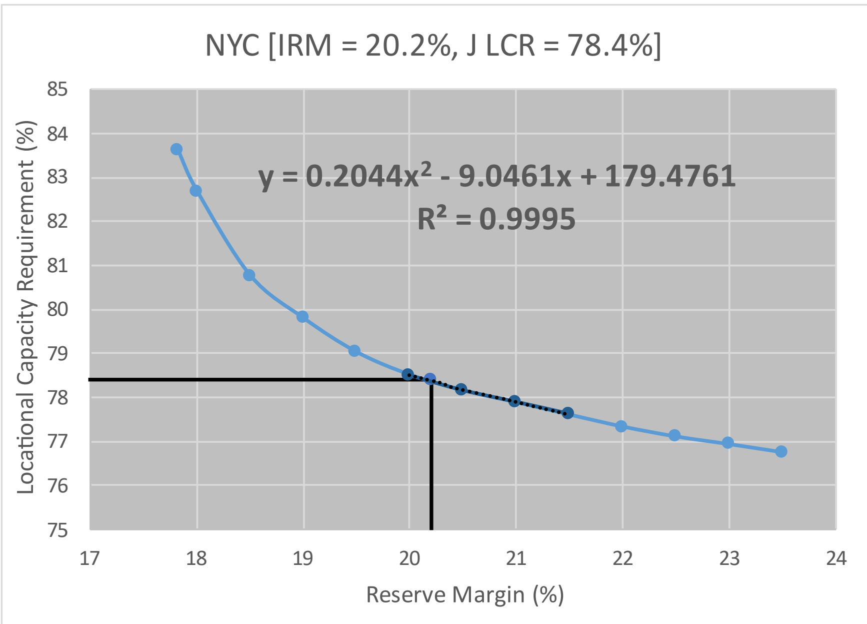
Using the GE-MARS program, a procedure is utilized for establishing NYCA IRM requirements (termed the *Unified Methodology*) which establishes a relationship between NYCA IRM and corresponding initial LCRs, as illustrated in Figure 3-2. All points on these curves meet the NYSRC 0.1 days/year LOLE reliability 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 5-15 provides a more detailed description of the Unified Methodology.

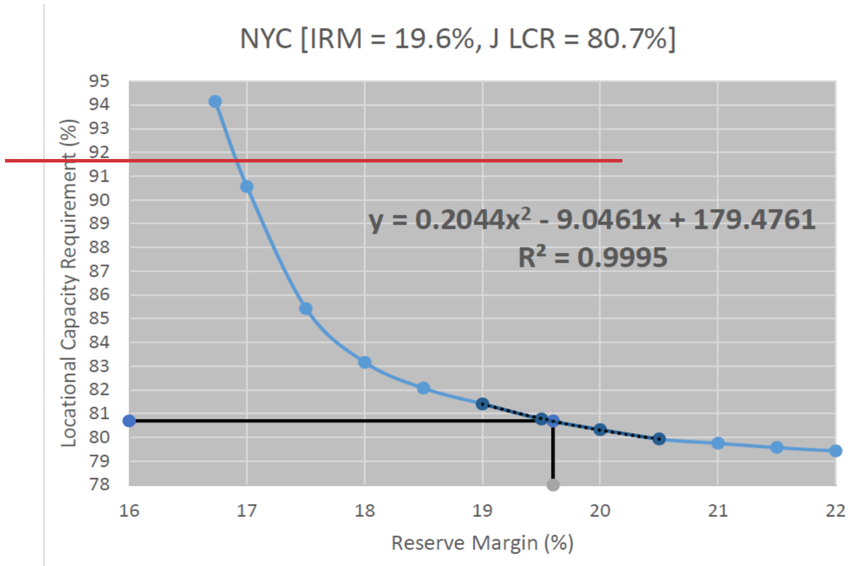
Figure 3-1 NYCA Load Zones



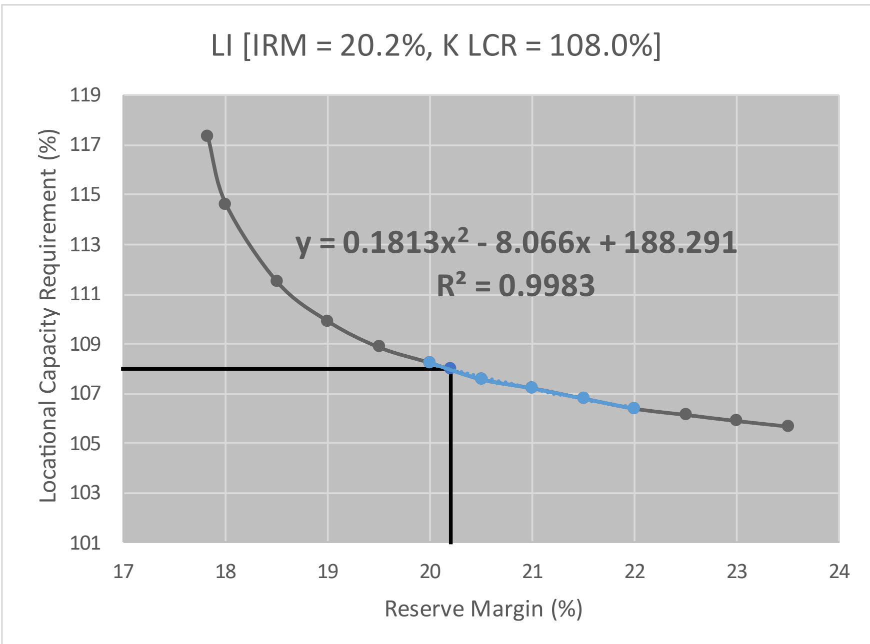
Base case NYCA IRM requirements and corresponding initial locality reserve margins for Zones J and K are established by a supplemental procedure (termed the *IRM Anchoring Methodology*), which is used to define an *inflection point* on each of these curves. These inflection points are selected by applying 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 5-15 provides a more detailed description of the methodology for computing the Tan 45 inflection point.

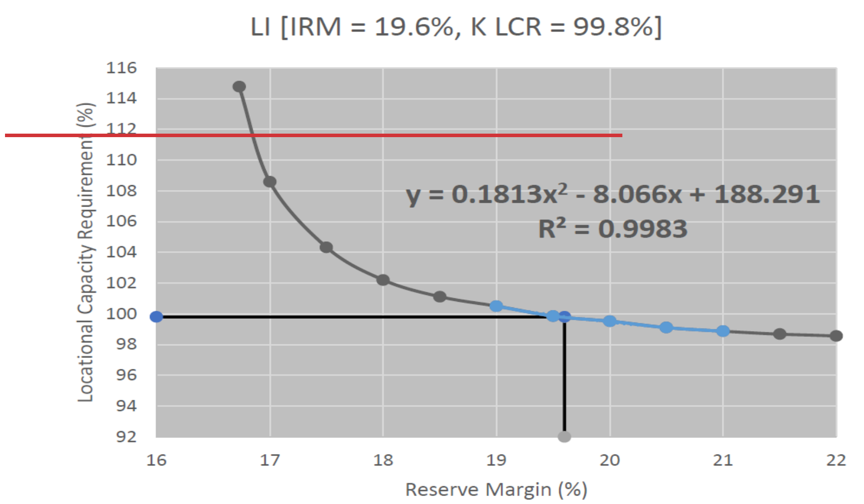
Figure 3-2 Relationship Between NYCA IRM and Corresponding Initial Locational Capacity Requirements





NYC [IRM = 19.6%, J LCR = 80.7%]
y = 0.2044x² - 9.0461x + 179.4761
R² = 0.9995
Locational Capacity Requirement (%)
Reserve Margin (%)


LI [IRM = 20.2%, K LCR = 108.0%]
y = 0.1813x2 - 8.066x + 188.291
R2 = 0.9983
Locational Capacity Requirement (%)
Reserve Margin (%)
119
117
115
113
111
109
107
105
103
101
17
18
19
20
21
22
23
24


LI [IRM = 19.6%, K LCR = 99.8%]
y = 0.1813x² - 8.066x + 188.291
R² = 0.9983
Locational Capacity Requirement (%)
Reserve Margin (%)
116
114
112
110
108
106
104
102
100
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4. Study Results – Base Case

Results of the NYSRC technical study show that the required NYCA IRM is ~~19.6~~20.2% for the 2023~~2~~ Capability Year under base case conditions. Figure 3-2 on page 8 depicts the relationship between NYCA IRM requirements and corresponding initial LCRs 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 ~~19.6~~20.2% for the 2023~~2~~ Capability Year, together with corresponding initial LCRs of ~~80.7~~78.4 % and ~~99.8~~108.0% 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 initial LCRs in this 2023~~2~~ IRM Study to 2022~~1~~ IRM Study results (New York City LCR= ~~82.6~~80.7%, Long Island LCR= ~~95.1~~99.8%), the corresponding 2023~~2~~ New York City initial LCR decreased by 2.~~2~~3%, while the corresponding Long Island LCR increased by ~~4.7~~8.2%.

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. In establishing the final LCRs, the NYISO will use the final IRM approved by the NYSRC.

A Monte Carlo simulation error analysis shows that there is a 95% probability that the above base case result is within a range of 19.5% and 19.7% (see Appendix A.1.1) when obtaining a standard error of 0.025 per unit or less at 1,202 simulated years. This analysis demonstrates that there is a high level of confidence that the base case IRM value of 19.6% is in full compliance with the one day in 10 years LOLE criterion in NYSRC Reliability Rule A.1.

5. Models and Key Input Assumptions

This section describes the models and related base case input assumptions for the 2023~~2~~ 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 2022 base case assumptions is also addressed in this section. The input assumptions for the final base case were approved by the Executive Committee on October 15, 2021, except for the transfer capability of the

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Neptune Cable[7] which was revised and made part of the final base case following a Special Sensitivity analysis as per Policy 5-15. Appendix A, Section A.3 provides more details of these models and assumptions and comparisons of several key assumptions with those used for this 2022 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 202~~2~~3 NYCA summer peak load forecast of 32,~~139~~246 MW was assumed in the 202~~2~~3 IRM Study, an ~~de~~increase of 10~~4~~7 MW from the forecast used in the 202~~1~~2 IRM Study. ~~The 2022 forecast also incorporated updated analysis indicating reduced non-coincident peak loads for each utility.~~ This "Fall 202~~2~~3 Summer Load Forecast" was prepared for the 202~~2~~3 IRM Study by the NYISO staff in collaboration with the NYISO Load Forecasting Task Force and presented to the ICS on October ~~6~~5, 202~~1~~2. The 202~~2~~3 forecast considered actual 202~~1~~2 summer load conditions.

The peak load forecast change shown on Table 5-1 below, indicates ~~a reduction~~an increase in peak loads in ~~the heavily loaded zones~~Zone J, ~~(Zones J and K)~~ while the peak loads for upstate zones (zones A-I) ~~continue to grow~~decline. The Zone K forecast level is similar to that from the 2022 IRM forecast, with slight decrease. The decrease in Zone A to I peak load forecast level is driven by a combination of lower experienced summer 2022 levels in some upstate areas, lower regional load growth projections in some areas, and an aggregate decrease in projected load levels for large load ~~project load projections~~facilities. The increase in the Zone J forecast level is driven by higher experienced load levels; along with strong peak load growth projections driven by increased electric vehicles and appliance electrification drivers, decreased energy efficiency and storage peak reduction impacts, strong commercial and residential load growth, and a continued load recovery from the COVID-19 pandemic. ~~The slight decrease in forecast level is primarily attributed to lower experienced summer 2022 load levels.~~

~~The decrease in the Zone J load forecast is in part due to the continued impacts of the COVID-19 pandemic. With a lower percentage of the NYCA load in Zones J and K, the dependence on~~

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[7] *See* footnote 3 page 3

~~the cable interface is reduced. This, combined with the lower noncoincident peak loads results in a lower IRM.~~

Table 5-1: Comparison of 202~~1~~2 and 202~~2~~3 Actual and Forecast Coincident Peak Summer Loads (MW)

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	Fall 202~~1~~2 Forecast	202~~1~~2 Actual	202~~1~~2 Normalized[8]	Fall 202~~2~~3 Forecast	Forecast Change
	(a)	(b)	~~c~~(c)	(d)	= (d) ~~-~~– (a)
Zones A-I	16,~~008~~037	1~~5,120~~4,511	15,~~614~~608	1~~6,037~~5,828	~~29~~-209
Zones J&K	16,~~235~~102	15,~~177~~981	1~~5,944~~6,167	16,~~102~~418	~~-133~~+316
NYCA	32,~~243~~139	30,~~297~~492	31,~~558~~775	32,~~139~~246	~~-104~~+107

Use of the Fall 202~~2~~3 Load Forecast resulted in ~~an IRM XXdecrease of 0.7%~~a negligible increase compared to the 202~~1~~2 IRM Study (Table 6-1).

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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 (Zone J), Long Island (Zone K), Westchester (Zones H and I), and two rest of New York State areas (Zones A-E and 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 new LFU multipliers included summer 2021 data, which was not included in prior LFU models. ~~In general~~With the exception of Zone K, the load response to weather in 2021 was

Commented [DA6]: Is this accurate? Wasn't it included in last year's model? Obviously the 2022 data wasn't included in last year's work, but isn't that obvious. I think you are referring to the multipliers.

Commented [HY7R6]: Confirmed correct

[8] The "normalized" 2022 peak load reflects an adjustment of the actual 2022 peak load to account for the load impact of actual weather conditions, demand response programs, and municipal utility self-generation.

~~less~~lower in magnitude than it was in previous hot summers. The slope of load versus weather has recently decreased, resulting in smaller LFU multipliers in the upper bins. This change has resulted in lower LFU impacts on the IRM than in previous years.

~~In addition, aA thorough review of the bin structure was conducted for the 20223 IRM Study. This review indicated that the midpoint of each bin should be changed from a simple arithmetic average to a frequency weighted midpoint. This change was approved and implemented for thisbeginning with the 2022 study. Further description can be found on the NYSRC website[9].~~

A sensitivity case shows that the modeling of LFU in the 2023~~2~~ IRM Study has an effect of decreasing IRM requirements by ~~7.9%~~8.2% (Table 7-1, Case 3), as compared to a range of 7.2% to 9.1% in the previous five IRM studies. Also, the new LFU model resulted in a 0.6% ~~1%~~ reduction in the IRM – see Table 6-1: Parametric IRM Impact Comparison – ~~2021~~ 2022 IRM Study vs. ~~2022~~ 2023 IRM Study page 21.

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 IRM study and was again utilized for the 2023~~2~~ IRM Study. This multiple load shape feature enables a different load shape to be assigned to each of seven load forecast uncertainty bins.

For the 2023 IRM study, a combination of load shape years 2013, 2017, and 2018 were selected by ICS as representative years, as recommended under the LFU Phase 2 Study.[10]~~.~~ This is a change from the 2022 IRM study where 2002, 2006, and 2007 were utilized as representative years. The load shape curves were reviewed as part of the 2023 IRM Study to ensure that the curves being utilized most accurately represent the expected load shapes for the seven load forecast uncertainty bins moving forward. NYISO, as part of its load shape review, recommended updating Bin 1 from 2006 to 2013, Bin 2 from 2002 to 2013, Bins 3 and 4 from 2007 to 2018, and Bins 5, 6, and 7 from 2007 to 2017. The recommendation to change the bin structure was adopted by ICS and implemented for the final base case of the 2023 IRM study.

~~[9] https://nysrc.org/PDF/MeetingMaterial/ICSMeetingMaterial/ICS%20Agenda%20245/AI%207.1%20-%20LFU_Study_Phase_1_Overview_ICS_20210330.pdf~~

[9] https://www.nysrc.org/PDF/MeetingMaterial/ICSMeetingMaterial/ICS%20Agenda%20259/A.I.10-LDC_Recommendation_ICS[4098].pdf

Commented [HY8]: To be confirmed with table 6-1 pending FBC

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The load shape for the year 2018 was selected to represent average summer peak day weather. The load shape for the year 2017 was selected to represent a flatter load shape typical of a cooler than normal summer. The load shape for the year 2013 was selected to represent a steeper load shape typical of a hotter than normal summer. The 2013, 2017, and 2018 load shapes were adjusted to account for the expected 2023 BTM Solar penetration level.

The load duration curve review was the second phase in a multiyear study that includes an extensive load shape and load forecast uncertainty review. The third phase in the load forecast uncertainty modeling review will focus on issues that should become more critical in the future, such as the NYISO trend toward a winter peaking system, increased focus on extreme weather assumptions and scenarios due to climate change, and increased load variability and evolving shapes due to increasing levels of BTM Solar. The third phase is anticipated to be completed prior to the 2024 IRM study.

~~ICS has established criteria for selecting the appropriate historical load shapes to use for each of these load forecast uncertainty bins. For this purpose, a combination of load shape years 2002, 2006, and 2007 were selected by ICS as representative years for the 2022 IRM Study. The load shape for the year 2007 was selected to represent a typical system load shape over the 1999 to 2017 period. The load shape for 2002 represents a flatter load shape, *i.e.*, a shape that has numerous daily peaks that are close to the annual peak. The load shape for 2006 represents a load shape with a small number of days with peaks that are significantly above the remaining daily peak loads. The combination of these load shapes on a weighted basis represents an expected probabilistic LOLE result.~~

~~The load duration curves were reviewed as part of the 2021 IRM Study. These curves were examined for the period 2002 through 2019. It was observed that the year 2012 was similar to the year 2007, the year 2013 was similar to 2006, and the year 2018 was similar to the year 2002. As a result of this review, the ICS decided to continue using the current three load shapes.~~

~~The load shape selection process is the third leg in a multiple year study that had included an extensive load forecast review and an extensive load forecast uncertainty review. The extensive load shape review is expected to be completed in time for the 2023 IRM study.~~

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 ~~2022~~ 2023 IRM Study are shown in Appendix A, Section A.3.4. 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 DMNC ratings for existing facilities is seasonal tests required by procedures in the NYISO Installed Capacity Manual.

~~While there are no new conventional units planned, 111.2 MW of project related re-ratings are projected along with 19.1 MW of retirements.~~ There are no new thermal/conventional units planned, and ~~there are~~ 1205.2 MW of projected ~~retiremnets~~retirement. The significant amount of retirement is driven by the first phase of compliance obligations under the New York State Department of Environmental Conservation ("DEC") regulation to limit NOx emissions from simple cycle combustion turbines ("the Peaker Rules").

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 at least 220 MW and a total host load of ~~149.4~~157.5 MW, are included in this ~~2022~~ 2023 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 ~~2022~~2023 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 analysis concluded that these environmental initiatives would not result in NYCA capacity reductions or retirements that would impact IRM requirements during the summer of ~~2022~~2023. 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 B, Section B.2.

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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 MW of hydro facilities, will account for a total of ~~7,081~~7413 MW of NYCA renewable resources represented in the ~~2022~~ 2023 IRM Study.

It is projected that during the ~~2022~~ 2023 summer period there will be a total wind capacity of ~~2,017.5~~2351.1 MW participating in the capacity market in New York State. This represents an increase in available wind resources of ~~158.1~~539.3 MW and reflects the addition of ~~one~~ five new wind resources~~ and the capacity market entrance of an existing wind resource~~. All wind farms are presently located in upstate New York in Zones A-E.

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 ~~2022~~ 2023 IRM Study used available wind production data covering the years ~~2016~~ 2017 through ~~2020~~2021. For any new wind facilities, zonal hourly wind shape averages or the wind shapes of nearby wind units will be modeled.

Overall, inclusion of the projected ~~2017.5~~2351.1 MW of wind capacity in the ~~2022~~ 2023 IRM Study accounts for ~~5.6~~6.1% of the ~~2022~~ 2023 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 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 ~~99.3~~97.7 MW and are included in the above total.

For the ~~2022~~ 2023 study, there were ~~182.9 MW of~~no utility level solar generation additions. The total NYS Bulk Power System (BPS) solar capacity in the IRM Study is 214.4 MW. Actual hourly solar plant output over the ~~2016~~2017-~~20~~ 21 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

In 2019, the NYISO filed, and in 2020 FERC approved tariff changes that became effective May 1, 2021 enhancing 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 by August 1st for the upcoming capability year (i.e., August 1, 2021 for the Capability Year beginning on May 1, 2022).

To accommodate this new classification of resources, the 2021 IRM study adopted the simplified modeling approach by which Energy Limited Resources (ELR) units were dispatched at pre-determined output levels. Due to the lack of flexibility of the simplified approach, the NYISO and GE developed the dynamic ELR functionality within the GE-MARS program and recommended in the ELR Whitepaper[11] the TC-4C configuration which was tested with sensitivity cases in the 2022 IRM Study. In this 2023 IRM, an enhanced TC-4C configuration, which allowed more flexibility by modeling the energy limitation on a monthly basis, was tested in the Preliminary Base Case sensitivity and this dynamic ELR functionality was then adopted into the Final Base Case.

In general, the dynamic ELR functionality has an impact of lowering the IRM in a range between 0.8% and 0.5%, as compared to the simplified fixed-output approach. Compared to the simplified approach, the dynamic ELR functionality also has an impact on reducing the SCR calls during the emergency operating procedures (EOP), which will be discussed further in Section 5.2.5 – Emergency Operating Procedures.

~~Due to the lack of flexibility of the simplified approach, the NYISO and GE expanded the capabilities of the GE-MARs program to model ELRs, by implementing new functionalities, Energy Storage ("ES") and Energy Limited Type 3 ("EL3") unit types, with the capability of reflecting energy and duration limitations of the ELRs. The testing of the MARS ELR functionalities is reported in the ELR Whitepaper[12] which was approved by the NYSRC Executive~~

[11] The ELR Whitepaper can be found on the NYSRC website: https://www.nysrc.org/PDF/Reports/IRM%20White%20Papers/ELR%20Modeling%20White%20Paper%20May%202021%20FINAL.pdf

~~[12] The ELR Whitepaper can be found on the NYSRC website: https://www.nysrc.org/PDF/Reports/IRM%20White%20Papers/ELR%20Modeling%20White%20Paper%20May%202021%20FINAL.pdf~~

~~Committee in May 2021. The ELR Whitepaper recommended that prior to the full adoption of the MARS ELR functionalities, the 2022 IRM study should include a sensitivity case using the functionalities with the TC-4C configuration, while the simplified approach continues to be part of the base case modeling. Therefore, the ELR sensitivity is conducted on both the PBC and the FBC, which also provides additional comparisons between the MARS ELR functionalities and the simplified approach. Based on the results shown in Table 7-1, the MARS ELR functionality would lower the IRM by about 0.8% while having small impacts on the preliminary LCRs, compared to the simplified approach with pre-determined outputs from the ELRs.~~

~~The introduction of output duration limitations on resources (ELRs) caused a significant increase in the number of times the GE-MARS simulation utilized emergency operating procedures (EOP) to resolve a shortage. It is important to note that a "shortage" can be for a duration of an LOLE event as low as one hour, or as little as a single MW necessary to bring the system back to criteria. Making an SCR call~~ x ~~is the first step in the EOP process. This observation is further discussed in the Section 5.2.5 – Emergency Operating Procedures.~~

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 forced outage rate during demand periods (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. 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 2023~~2~~ IRM Study covered the 2017~~6~~-2021~~0~~ period.

The weighted average five-year EFORd for generating units calculated for units in Zones G-I, J and K for ~~-~~the 201~~6~~7-21~~0~~ period is lower than the 2016~~5~~-20~~19~~ average value used for the 2022~~1~~ IRM Study. ~~–~~This decrease in average forced outage rates lowers the IRM by 0.3% (Table 6-1). Appendix A, Figure A.5 depicts NYCA and Zonal five-year average EFORd trends from 2014~~3~~ to 2021~~0~~.

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5.2.5 Emergency Operating Procedures (EOPs)

In modeling of duration limited resources for 2021 IRM ~~study~~Study, the need for SCR resources increased to 170.1 days (probabilistic expected value) from the 2020 value of 8.2 days. In the 2022 IRM ~~s~~Study, the need for SCR resources was reduced to 38 days by redistributing the operating reserves and removing maintenance outside of the summer season. In the 2023 IRM ~~s~~Study, the West Central Reverse Limit was increased from 1600 MW to 2275 MW based on the updated Summer 2022 Operating Study. The increased limit substantially reduced the need for SCR activation as more MW can flow into Zone A and B where most of the SCRs activations were triggered. In addition, the adoption of the dynamic ELR modeling, which increases the flexibility in utilizing the energy limitations of the ELR units, further lowered the need for SCR resources. Therefore, the updated West Central Reverse Limit and the adoption of the dynamic ELR modeling reduced the SCR activations to ~~XX~~7.3 days per year, which is consistent with the historical level. (~~The NYISO and NYSRC evaluated several enhancements to more accurately capture EOP activations over the course of the 2022 IRM study. These included redistributing operating reserves so unnecessary EOP activations would not be triggered, reviewing, and removing shoulder season maintenance, (large EOP impact, no LOLE impact), evaluating the impact of ELR flexibility on EOP activation, and evaluating whether modeling economic imports from our neighbors would affect EOP calls. Each of these significantly reduced EOP calls. The 2022 IRM FBC includes updated operating reserves and maintenance modeling assumptions. This reduced EOP activations by approximately 78%, to 38 days per year. But for substantial load growth in Western NY, these calls would have been even lower.~~

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(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 2022~~1~~ registration. For the month of July, the forecast SCR value for the 2023~~2~~ IRM Study base case assumes that 1,225 ~~1,164~~ MW will be registered, with varying amounts during other months based on historical experience. This is ~~31 MW lower~~61 MW higher than that assumed for the 2022~~1~~ IRM Study.

As indicated above, the number of SCR calls in the 2023~~1~~ Capability Year for the 2023~~2~~ 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 2023~~2~~ IRM Study is based on a recent analysis of performance data for the 2012-2021~~0~~ period. This analysis determined a SCR overall performance factor of 69.9%~~69.6%~~. This is 0.3% ~~0.8 %~~ higher than the performance factor used in the 2022~~1~~ IRM Study (refer to Appendix A, Section A.3.9 for more details). Although both the overall SCR participation and performance factor improved compared to the level assumed in the 2022 Study, an increase in participation level in Zone J and a decline in performance factor in Zone K had an offsetting effect and therefore the updated SCR model had a minor impact on system reliability. ~~Although overall SCR performance factor improved compared to the level assumed in the 2021 Study, a decline in downstate performance resulted in a net IRM increase of 0.1% compared to last year's study (Table 6-1). At the same time, NYC and G-J Locational requirements fell. On net, updated SCR modeling had a minor impact on reliability while slightly changing the distribution of requirements.~~

Incorporation of SCR~~s~~ in the NYCA capacity model has the effect of increasing the IRM by 2.9% ~~2.7 %~~ (Table 7-1, Case 5). This increase results from the lower overall availability of SCR~~s~~ compared to the average statewide resource fleet availability.

(2) Other Emergency Operating Procedures

In addition to SCR~~s~~, the NYISO will implement several other types of EOP steps, such as voltage reductions, as required, to avoid or minimize customer disconnections. Projected 2023~~2~~ EOP capacity values are based on recent actual data and NYISO forecasts.

In the 2023 IRM Study, the NYISO implemented the modeling change to maintain 350 MW of 10-min operating reserve during 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.[13]~~.~~ Maintaining 350 MW of 10-min operating reserve has the effect of increasing the IRM by 1.5% (Table 7-1, Case 7), as a reduced amount of 10-min operating reserve is made available during the EOP step.

[13] The recommendation of maintaining OR at load shedding was presented at the 5/4 ICS meeting: https://www.nysrc.org/PDF/MeetingMaterial/ICSMeetingMaterial/ICS%20Agenda%20260/Operating_Reserve_Recommendation_ICS05042022_V4_Updated[4867].pdf

Refer to Appendix B, Table B.2 for projected EOP frequencies for the 2023~~2~~ Capability Year assuming the 20.2%~~xx%~~~~19.6%~~ base case IRM.

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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 ~~benefits~~when coupled with a non-locational ICAP Supplier. ~~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. 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 2023~~2~~ 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[14], 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 2023~~2~~ IRM Study incorporates the confidential elections that these facility owners made for the 2023~~2~~ Capability Year. The 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.

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 2023~~2~~ IRM Study were developed from emergency transfer limit analysis included in various studies performed by the NYISO, and from input from Transmission Owners

[14] *See* footnote 3 page 3

[15] The transmission model is discussed in Appendix A Section 3.5

and neighboring regions. The transfer limits are further refined by additional assessments conducted for this IRM Study topology.

The transmission model assumptions included in the 2023~~2~~ IRM Study are listed in Table A.10 in the Appendix which reflects changes from the model used for the 2022~~1~~ IRM Study. These topology changes are as follows:

UPNY-ConED Interface Limits

- Series reactors M51 & M52 and Dunwoodie 71 and 72 will change from bypassed to in service starting 2023
- Zone G to Zone H transfer limit decreases to 6675 MW from 7000 MW

West Central Reverse Limit

- The thermal ratings on the limiting circuit segments are increased due to the local upgrades by the Transmission Owners
- Zone C to Zone B transfer limit increases to 2275 MW from 1600 MW

Central East and Central East + Marcy Group Limits

- Updated Central East Voltage Collapse Limit captures the impact from the construction of Segment A Project (of AC Transmission Project)
- Central East forward limits (Zone E to Zone F) are reduced based on the associated dynamic limit conditions as shown in Table A.10 in Appendix A
- Proportional derates are applied to Central East + Marcy Group forward limits (Zone E to Zone G) as shown in Table A.10 in Appendix A
- Associated decreases are also applied to Zone E to Zone F dynamic limits
- Zone E to Zone G normal transfer limit decreases to 4260 MW from 4515 MW
- Associated decreases are also applied to Zone E to Zone G dynamic limits

Restoration of Neptune UDR Import Limit

- The import limit from the Neptune UDR was reduced to 330 MW in the 2022 IRM study due to the extended outage on the transformer named “NEWBRDGE 345 138 BK 1”. The

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transformer is expected to return to service during the 2023 ~~c~~Capability ~~y~~Year and therefore the import limit from the Neptune UDR is restored to the full 660 MW in the 2023 IRM study.

Update to Zone K export limits

- Export limits from Zone K (Y49/Y50, ConED-LIPA and LI-WEST) are reduced due to the anticipated retirement of Trigen and the derate on 138-291
- Y49/Y50 forward limit reduce~~s~~d to 420 MW from 515 MW
- ConED-LIPA forward limit reduce~~s~~d to 135 MW from 220 MW
- LI-WEST forward limit reduce~~s~~d to 49 MW from 134 MW

Update to Ontario import limits

- The outage impacting phase shifters L33/34P is expected to end by summer 2023, restoring the transfer limits between IESO and NYCA. See Table A.10 in Appendix A

~~***Western NY Limits – Public Policy Impact***~~

- ~~Zone A export limit increases to 2650 MW from 1850 MW~~
- ~~Zone A to B limit increases to 2200 MW from 1700 MW~~
- ~~Zone B to C limit increases to 1500 MW from 1300 MW~~

  ~~Note: while the Western NY Public Policy Transmission Project increased transmission capability flowing from west to east *out* of Zones A and B, transmission import capability flowing from the east to west *into* Zones A and B remained unchanged.~~

~~***Cedars Import Limit***~~

- ~~Import Capability to Zone D from Chateguay increases to 1,770 MW from 1,690 MW~~

~~***Derates to Central East***~~

- ~~Porter-Rotterdam (30 & 31) lines will be out of service~~
- ~~Derates applied to both individual and group limits~~
- ~~See table A.10 and A.11 in Appendix A~~

~~***Updates to Zone K Topology***~~

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- ~~ConEd-LIPA Dynamic Rating table for Zone K to I and J increases - see table A.11~~

~~Extended Partial Outage Impacting the Transfer Capability of the Neptune UDR~~~~[16]~~

- ~~The transformer named "NEWBRDGE_345_138_BK_1" extended its outage to August 1st 2022. This impacts the Neptune UDR transfer capability. The 660 MW capability is reduced to 375 MWs.~~

Forced transmission outages based on historic 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 Transmission Owners (TOs) provided updated transition rates for their associated cable interfaces. Updated cable outage rates assumed in the 2023~~2~~ IRM Study resulted in a 0.6% ~~0.2 %~~ increase in the IRM compared with the 2022~~1~~ IRM Study (Table 6-1).

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As in all previous IRM studies, forced outage rates for overhead transmission lines were not represented in the 2023~~2~~ 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 NYC (Zone J) and LI (Zone K). To illustrate the impact of transmission constraints on the IRM, if internal NYCA transmission constraints were eliminated, the required 2023~~2~~ IRM could decrease by 2% ~~1.9%~~ (Table 7-1, Case 2).

~~[16] *See* footnote 3 page 3~~

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 2023~~2~~ 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.

Representing Outside World Area interconnection support in IRM studies significantly reduces IRM requirements. For the previous seven IRM studies, EA has reduced IRM requirements in the range of 6.9 to 8.7%.[17]

In 2019, the ICS conducted an analysis of the IRM study's Outside 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. The ICS used this new model in the current study (2022) as well as in the 2021 IRM Study.[18]

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[17] *See* 2015 to 2022~~1~~ IRM Study reports at www.nysrc.org/reports3.html.

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

During the 2023~~2~~ Capability Year, Hydro-Quebec is expected to wheel 300 MW of capacity through NYCA to New England. In addition, the 2023~~2~~ IRM study continues to limit the EA assistance to a maximum of 3,500 MW as applied in the previous four IRM Studies[19].

Utilizing the improved Outside Area Model, while including the Hydro-Quebec wheel to New England and continuing to represent the 3,500 MW EA limit described above, reduces the NYCA IRM by 7.6% ~~8.6%~~ (Table 7-1, Case 1). This is 1% less ~~1.7% more~~ than the impact determined in the 2022~~1~~ IRM Study.

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

The NYISO, GE, and Transmission Owner reviews found a few minor data errors, with no material effect on IRM requirements in the preliminary base case. The data found to be in error by these reviews were corrected before being used in the final base case studies. A summary of these quality assurance reviews for the ~~2021~~ 2023 IRM Study input data is shown in Appendix A, Section A.4.

6. Parametric Comparison with ~~2021~~ 2022 IRM Study Results

The results of this 2023~~2~~ IRM Study show that the final base case IRM result represents a 0.6%~~XX%~~ ~~1.1% decrease~~ increase from the ~~2021~~ 2022 IRM Study base case value. 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 studies were conducted to update the underlying IRM model data and test the IRM impact of individual parameters. In practice, the

[19] The 2018 IRM Study report, pages 17-18, describes this EA limit and its derivation. See www.nysrc.org/reports3.html.

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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. Therefore, some of t~~T~~he IRM impacts ~~of each parameter~~ shown in Table 6-1 reflect the impacts from separate Tan45 analysis, while some represent the results from parametric analysis. ~~in this analysis was normalized~~ 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 ~~1.1%~~0.6~~xx~~% IRM ~~decrease~~ increase from the ~~2021~~ 2022 IRM Study. Table 6-1 also provides the reason for the IRM change for each study parameter from the ~~2021~~ 2022 IRM Study.

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There are seven parameter drivers that in combination *increased* the 2023 IRM from the 2022 base case IRM by 3.8%. Of these seven drivers, the two most significant are the addition of 539.3 MW of wind units which increased the IRM by 1.2% and the withholding of 350 MW of Operating Reserve at load shedding which increased the IRM by 1.1%. The change in UDR elections caused a 0.8% increase. This was followed by updates of the outside areas and Policy 5 adjustments which increased the IRM by 0.3%, and lower DMNC ratings in the downstate areas which increased the IRM by 0.2%. Two other factors are shown on table 6-1 and result in an additional 0.2% increase in the IRM.

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Six parameter drivers in combination decreased the IRM from the 2022 base case by 3.2%. Of these six drivers, the most significant was the Peaker deactivations in NYC which decreased the IRM by 0.9%. Updates to the ELR modeling, which increased their availability reduced the IRM by 0.8%. The lowering of several of the high load bins of the updated Load Forecast Uncertainty model also resulted in a 0.6% IRM reduction. Topology updates, including restoration of Neptune decreased the IRM by 0.5% and the new load shapes, which replaced 2002, 2006 and 2007 shapes with 2013, 2017 and 2018, reduced the IRM by an additional 0.3%. Finally, the update in the Run of River shapes reduced the IRM by an additional 0.1%

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~~There are *seven parameter drivers* that in combination *increased* the 2022 IRM from the 2021 base case IRM by 1.7%. Of these seven drivers, the two most significant are the addition of 158 MW of wind and 183 MW of solar units which increased the IRM by 0.6% and the partial outage of the Neptune UDR[20] which increased the IRM by 0.5%. These were followed by reduced availability of the~~

~~[20] *See* footnote 3 page 3~~

~~subterranean cables surrounding New York City and Long Island which increased the IRM by 0.2%. Four other factors are shown on table 6-1 and resulted in an additional 0.4% increase in the IRM.~~

~~Seven parameter drivers in combination decreased the IRM from the 2021 base case by 2.8%. Of these seven drivers, the most significant are a new summer LFU model which decreased the IRM by 1.0%, and a new load forecast reducing the IRM by 0.7%.~~

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

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~~Parameter~~	~~Estimated IRM Change (%)~~	~~IRM (%)~~	~~Reasons for IRM Changes~~
~~2022-23 IRM Study – Final Base Case~~		~~19.6~~	
~~2023-24 IRM Study Parameters that increased the IRM~~			
~~Withhold 350 MW OR at Load Shed~~	~~0.50~~		~~Removing available MWs from OR EOP step increases (inc.) the IRM.~~
~~Addition of 417.5 MW New Wind Units~~	~~0.40~~		~~Lower availability of wind inc. the IRM~~
~~Cable Transition Rates~~	~~0.20~~		~~Outage rate inc. for Y49 and Neptune impacts IRM~~
~~Update of external Areas + Policy 5~~	~~0.10~~		~~Policy 5 adjustment incr. the IRM~~
~~DMNC Updates~~	~~0.10~~		~~Lower DMNC MW in downstate~~
~~Upstate Retirements~~	~~0.10~~		~~120 MW of retirements in load pocket~~
~~Thermal Outage Rate (2017-2021)~~	~~0.10~~		~~Inc. the EFORd~~
~~Non-SCR and Non-OR EOPs~~	~~0.10~~		~~A decrease in EOP MWs incr. the IRM~~
~~Total IRM Increase~~	~~1.6~~		
~~2023-24 IRM Study Parameters that decreased the IRM~~			
~~DEC Peaker Deactivation~~	~~-0.40~~		~~Peaker units have higher EFORd, deactivation lowers the system EFORd~~
~~Update ELR Model~~	~~-0.20~~		~~Inc. the availability of ELRs~~
~~New Summer LFUs~~	~~-0.20~~		~~Reduces the load forecast uncertainty~~
~~Topology Update + Neptune Rest.~~	~~-0.20~~		~~Inc. the system transfer capability~~
~~Gold Book Load Forecast for 2023~~	~~-0.10~~		~~Less load downstate~~
~~Total IRM Decrease~~	~~-1.1~~		
~~2023-24 IRM Study Parameters that did not change the IRM (Non-Material Changes)~~			
~~Winter LFU~~	~~0~~		
~~Update of Solar & LFG Shapes~~	~~0~~		
~~Update Run of River Shapes~~	~~0~~		
~~Update of Wind Shapes~~	~~0~~		
~~Update of SCRs~~	~~0~~		
~~Net Change from Previous Study~~		~~+0.5~~	
~~2023-24 IRM Study – Preliminary Base Case~~		~~20.1~~	

0.Table 6-1 for Final Base Case			
Parameter	**Estimated IRM Change %**	**IRM %**	**Reason for IRM Changes**
2022-23 IRM Study - Final Base Case (FBC)		**19.6**	
2023-24 IRM Study Parameters that Increased the IRM			
Addition of 549.3 MW New Wind Units	1.2		Lower availability of wind units.
Withhold 350 MW OR at Load Shed	1.1		Removing available MWs from Operating Reserve EOP step.
UDR Election	0.8		Cross Sound Cable election changed
Update of External Areas + Policy 5	0.3		Policy 5 adjustment reduced support from external areas.
DMNC Updates	0.2		Lower DMNC MW in downstate
Thermal Outage Rate (2017-2021)	0.1		Inc. the EFORd
Non-SCR and Non-OR EOPs	0.1		A decrease in EOP MW.
Total IRM Increase	**3.8**		
2023-24 IRM Study Parameters that decreased the IRM			
DEC Peaker Deactivation	-0.9		Peaker units have higher EFORd, deactivation lowers the system EFORd
Update ELR Model	-0.8		Inc. the availability of ELRs
New Summer LFUs	-0.6		Reduces the load forecast uncertainty
Topology Update + Neptune Rest.	-0.5		Inc. the system transfer capability
New Load Shapes	-0.3		Adopted the new load shapes.
Update Run of River Shapes	-0.1		Improvement in RoR performance.
Total IRM Decrease	**-3.2**		
2023-24 IRM Study Parameters that did not change the IRM			
Winter LFU	0.0		
Update of Solar and LFG Shapes	0.0		
Update of Wind Shapes	0.0		
Update of SCRs	0.0		
Net Change from Previous Study		0.6	
2023-24 IRM Study FBC		**20.2**	

FBC Tan45 Results 20.2

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 days/year.

Table 7-1 shows the IRM requirements for ~~9~~ 10 sensitivity cases. Because of the lengthy computer run time and personnel needed to perform a full Tan 45 analysis in IRM studies[21], 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 Loss of Load Hours (LOLH) and Expected Unserved Energy (EUE) reliability metrics for each case[22]. 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.

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

[22] **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**.**

[16] *See* NYSRC reports that provide more detail on the application of these metrics.in NYSRC IRM and resource adequacy studies.at:nysrc.org/reports3html under "Resource Adequacy Documents."

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. Four of these cases show reasonable results when compared to past results. These parameters and their IRM impacts are discussed in Sections 5.1.2 and 5.4, respectively.

The next ~~two~~ three sensitivity cases, Cases 6, ~~and~~ 7 and 8, illustrate the IRM impacts of ~~changing certain base case assumptions~~reversing the modeling changes adopted for the 2023 IRM study. Case 6 shows the impact of reversing the ELR model from the dynamic functionality to fixed output shapes. Case 7 shows the impact of not withholding the 350 MW Operating Reserve at load shedding. Case 8 shows the impact of reversing the load shapes to the historical modeling, i.e. the 2002, 2006 and 2007 load shapes.

The last two sensitivity cases, Case 9 and 10 are related to the outage with the Y49 cable. Case 9 shows the impact if the current outage on the cable Y49 is extended beyond summer 2023. Case 10 ~~shows the impact of adopting different transition rate assumptions for cable Y49, while the cable is assumed to be returned to service before summer 2023.~~ evaluates the impact of deviating from the Policy V-15 requirement to base cable outage rates on the cables on the last five years of outage data . This sensitivity eliminates the impact of the extensive Y49 cable outages that occurred in 2021 and 2022 by utilizing the same cable forced outage rates that were assumed for Y49 in the 2021 IRM study. The effect of the sensitivity is to take the extensive outage risk that occurred during these years and remove it from consideration as a risk to the New York electric system.

~~an earlier than expected completion of the Zone D PAR repair. Case 7 utilizes the new MARS ELR software TC-4C option as the basis for testing the ELR functionality. Case 7 was conducted on both the PBC and the Final Base Case (FBC) and both cases yield similar impacts on the Final IRM. With the MARS ELR functionality, the SCR calls dropped from by over 10 days per year. The ELR resources were modeled in the base case using a simplified representation of the energy limitations. This allowed a desired representation while a more detailed representation of the ELR limitations is studied over the course of the next six months.~~

~~Case 8 evaluates the impact of outage rates on the cables to Long Island. This sensitivity utilizes the same cable forced outage rates that were assumed in the 2021 IRM study. The final Case 9 evaluates the impact on the Neptune UDR transfer capability being fully available for the entire study period. Appendix B, Table B-1 includes a more detailed description and explanation of each sensitivity cases.~~

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~~Table 7-1: 2022 Final Base Case IRM Sensitivity Cases Results~~					
~~2022 IRM Study Case~~	~~Description~~	~~IRM (%)~~	~~IRM % Change from Base Case~~	~~LOLH hours/yr~~	~~EUE MWhr/yr~~
~~0~~	~~2022 IRM Final Base Case~~	~~19.6~~	~~-~~	~~0.341~~	~~207.3~~
~~IRM Impacts of Key MARS Study Parameters~~					
~~1~~	~~NYCA Isolated (no emergency assistance)~~	~~28.2~~	~~+8.6~~	~~0.298~~	~~163.4~~
~~2~~	~~No Internal NYCA transmission constraints~~	~~17.7~~	~~-1.9~~	~~0.365~~	~~303.0~~
~~3~~	~~No Load forecast uncertainty~~	~~11.7~~	~~-7.9~~	~~0.251~~	~~61.0~~
~~4~~	~~Remove all wind~~	~~14~~	~~-5.6~~	~~0.346~~	~~215.3~~
~~5~~	~~No SCRs~~	~~16.9~~	~~-2.7~~	~~0.324~~	~~178.4~~
~~IRM Impacts of Base Case Assumption Changes~~					
~~6~~	~~Advanced completion of Zone D PAR repair~~	~~19.5~~	~~-0.1~~	~~0.345~~	~~210.6~~
~~7~~	~~Enhanced Energy Limited Resource (ELR) functionality test (Tan 45).~~	~~18.8~~	~~-0.8~~	~~0.361~~	~~245.5~~
~~8~~	~~Revert to 2021 IRM Study Cable Forced Outage Rates (Tan 45)~~	~~19.5~~	~~-0.1~~	~~0.343~~	~~211.8~~

~~9~~	~~Neptune UDR fully available for the entire study period (Tan 45)~~	~~19.1~~	~~-0.5~~	~~0.341~~	~~211.4~~

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Table 7-1: 2023 Final Base Case IRM Sensitivity Case Results					
2023 IRM Study Case	Description	IRM (%)	IRM (%) Change from Base Case	LOLH (hrs/yr)	EUE (MWh/yr)
0	2023 IRM Final Base Case	20.2	-	0.364	202.8
IRM Impacts of Key MARS Study Parameters					
1	NYCA Isolated (No Emergency Assistance)	27.8	+7.6	0.321	148.7
2	No Internal NYCA Transmission Constraints	18.2	-2.0	0.380	290.4
3	No Load Forecast Uncertainty	12.0	-8.2	0.289	83.4
4	No Wind Capacity	14.1	-6.1	0.362	198.9
5	No SCR Capacity	17.3	-2.9	0.348	175.9
IRM Impacts of Base Case Assumption Changes					
6	Energy Limited Resource (ELR) (Fixed Output Shapes)	20.4	+0.2	0.371	205.2

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7	**Operating Reserves Not Maintained at Load Shedding**	18.7	-1.5	0.363	196.7
8	**Reverse New Load Shapes (Tan 45)**	20.5	+0.3	0.371	176.0
9	**Y49 Outage Extended Beyond June 2023**	20.8	+0.6	0.358	177.8
10	**Y49 Transition Rate Reverted to 2015-2019 Data**	19.7	-0.5	0.364	221.9

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 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.

The increase in wind resources raises the IRM because wind capacity has a lower contribution to reliability than traditional resources. UCAP is ICAP translated into perfect capacity and is a function of the performance of the resources. Resources with below average performance can increase the IRM as well as required ICAP. Figure 8-1 top of next page shows that required UCAP margins, which steadily decreased over the 2006-2012 period to the 5-6% range, and then remained fairly steady through 2019 but have been trending upwards through 2021 as has the IRM.

Appendix C provides details of the ICAP to UCAP conversion.

Figure 8-1 NYCA Reserve Margins