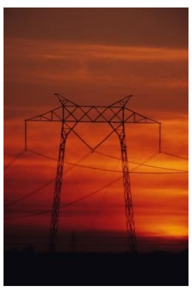
Technical Study Report

New York Control Area Installed Capacity Requirement



For the Period May ~~2023~~ 2024 to April ~~2024~~ 2025

~~December 9, 2022~~October 26, 2023

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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NOTE: Appendices A, B, C and D are included in a separate document.

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~~2024, through April 30, ~~2024~~ 2025 (2023 Capability Year). The IRM study described in this report for ~~2023~~ 2024 Capability Year is referred to as the "~~2023~~ 2024 IRM Study."

Results of the NYSRC technical study show that the required NYCA IRM for the ~~2023~~ 2024 Capability Year is ~~19.9~~23.1% under base case conditions. 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 ~~9~~8, ~~2022~~ 2023 for its adoption of the Final NYCA IRM requirement for the ~~2023~~ 2024 Capability Year.

In addition to calculating the LOLE the analysis also determined that the Hourly Loss of Load Expectation was 0.~~358~~ 377 hours per year and the Expected Unserved Energy (EUE) was ~~192.4~~225.092 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 projected ~~2023~~ 2024 NYISO energy value of 152,~~120~~ 140 GWh/year (~~2022~~ 2023 Gold Book) this produces a NEUE of 0.~~00013~~00015%. Other systems around the year 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.[2]

The NYSRC study procedure used to establish the NYCA IRM[3] also produces corresponding "initial" New York City and Long Island locational capacity requirements (LCRs) necessary to satisfy the NYCA resource adequacy criterion. The ~~2023~~ 2024 IRM Study determined initial LCRs of ~~78.2~~72.7% and ~~107.4~~103.2% for the New York City and Long Island localities, respectively. This represents a decrease of ~~2~~5.5~~5~~% for NYC and an increase of ~~7.6~~4.2% 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.

[1] A Capability Year begins on May 1 and ends on April 30 of the following year.
[2] Resource Adequacy for a Decarbonized Future. https://www.epri.com/research/products/000000003002023230
[3] 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."

The ~~19.9~~23.1% IRM base case value for the ~~2023~~ 2024 Capability Year represents a *~~0.3~~3.2% increase* from the ~~2022~~ 2023 base case IRM of 19.~~6~~9%. Table 6-1 shows the IRM impacts of individual updated study parameters that result in this change. In summary:

- 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 the AC Transmission topology 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 shapes caused a 0.13% increase.Lower DMNC ratings (Dependable Maximum Net Capability) in the downstate areas increased the IRM by 0.1%.
- Seven parameter drivers in combination *decreased* the IRM from the 2022 base case by 1.59%. Of these seven drivers, the most significant was the update in the Behind-the-Meter (BTM) Solar profiles which decreased the IRM by 0.5%. 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. Modifications in the External Areas and the subsequent Policy-5 adjustments resulted in a 0.37% decrease in 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%.

~~There are seven parameter drivers that in combination *increased* the 2023 IRM from the 2022 base%. 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 Unforced Capacity Deliverability Rights (UDR) elections caused a 0.5% increase. This was followed by updates of the outside areas including adjustments dictated by Policy 5-16 section 3.5.6 which ensure that the outside areas are no better than 0.1 Event-Days/year. This increased the IRM by 0.3%. Lower DMNC ratings (Dependable Maximum Net Capability) in the downstate areas 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 Energy Limited Resource (ELR) modeling, which enabled greater targeting of their generation reduced the IRM by 0.8%. The lowering of several of the high load bins of the updated Load Forecast Uncertainty (LFU) model also resulted in a 0.6% IRM reduction. Topology updates, including restoration of the Neptune cable 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%~~

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. NYSRC Policy 5-16 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 ~~19.9~~23.1% IRM will fully meet NYSRC and NPCC resource adequacy criterion that require a Loss of Load Expectation (LOLE) of no greater than 0.1 Event-Days/year.

The ~~2023~~ 2024 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 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 shows that required UCAP margins displaying slightly steeper slope when following the trend of required ICAP margins. This is due to resources with below average performance being added to the system and the required UCAP is a function of required ICAP and the weighted average availability of system resources. Basically, when the EFORd goes up, because the UCAP is calculated as ICAP x (1-EFORd), the UCAP movement is more sensitive to the downward IRM movement—i.e., having a steeper slope than the IRM curve.

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~~ 2024 through April 30, ~~2024~~ 2025 (~~2023~~ 2024 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 5-16, *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~~ 2024 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~~ 2024 Capability Year (~~2023~~ 2024 IRM Study) are set forth in NYSRC Policy 5-16. The primary reliability criterion used in the IRM study requires an 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 5-16 and discussed in detail later in this report.

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 5-16 – 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~~ 2024

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

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

Capability Year, the NYISO will continue utilizing an economic optimization methodology approved by the Federal Energy Regulatory Commission.

The ~~2023~~ 2024 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~~2023, 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~~ 2022 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 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

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

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 ~~2023~~ 2024 IRM Study are described in detail in NYSRC Policy 5-16, *Procedure for Establishing New York Control Area Installed Capacity Requirements and the Installed Reserve Margin (IRM)*. Policy 5-16 also describes the computer program used for reliability calculations and the types of input data and models used for the IRM Study.

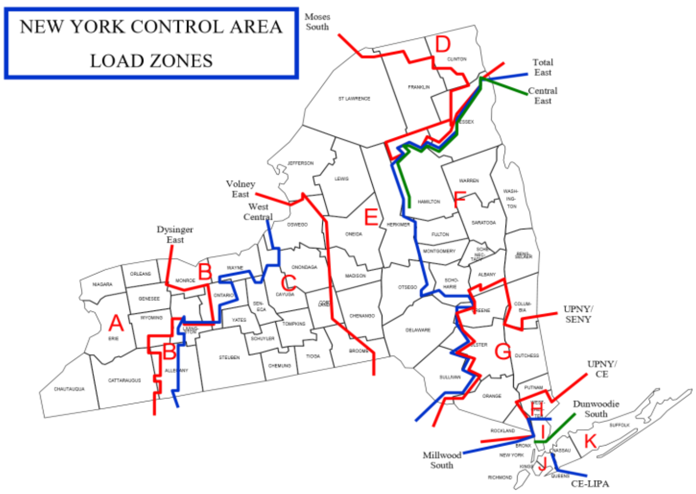
This study utilizes a *probabilistic approach* for determining NYCA IRM requirements. This technique calculates the probabilities of generator unit outages, in conjunction with load and transmission representations, to determine the Event-Days per year of expected resource capacity shortages.

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 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~~ 2024 IRM Study, were simulated using all hours in the year.

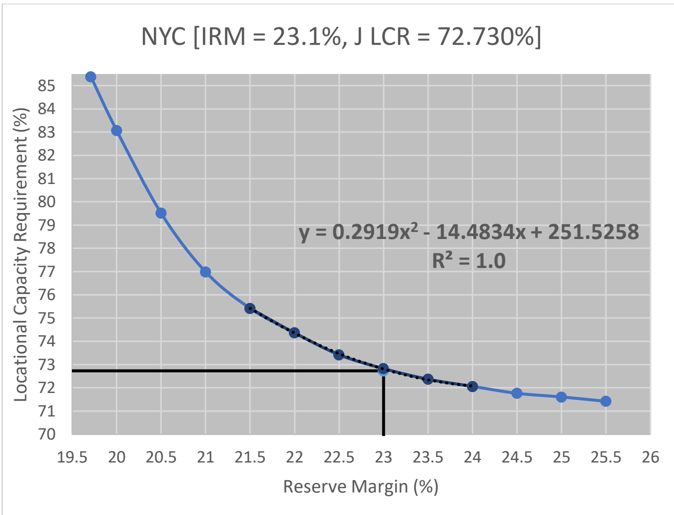
Using the GE-MARS program, a procedure is utilized for establishing NYCA IRM requirements (termed the *Unified Methodology*) which establishes a relationship between NYCA IRM and corresponding initial LCRs, as illustrated in Figure 3-2. All points on these curves meet the NYSRC 0.1 Event-Days/year LOLE 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 5-16 provides a more detailed description of the Unified Methodology.

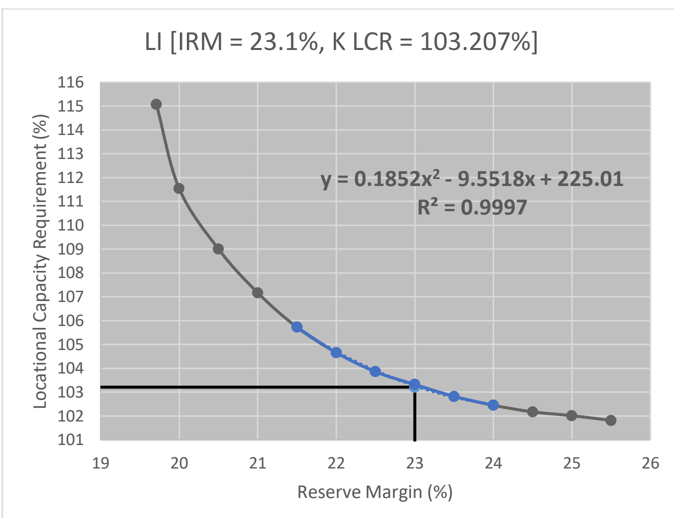
Figure 3-1 NYCA Load Zones

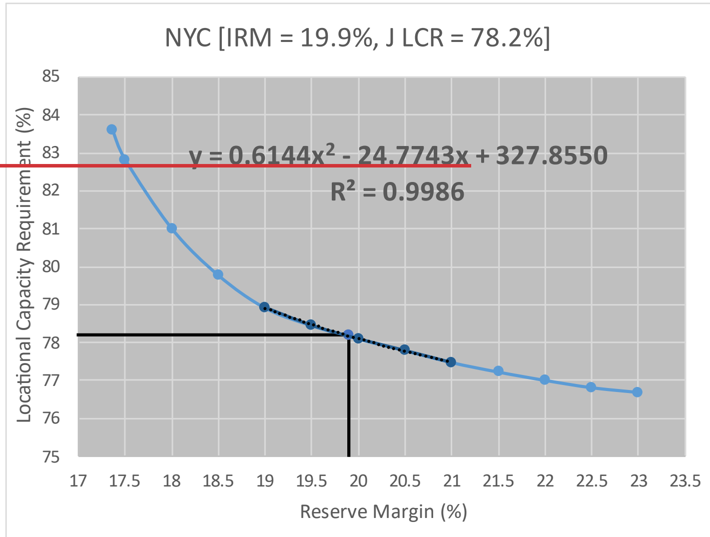


Base case NYCA IRM requirements and corresponding initial locality reserve margins for Zones J and K are established by a supplemental procedure (termed the *IRM Anchoring Methodology*), which is used to define an *inflection point* on each of these curves. These inflection points are selected by applying 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 5-16 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 ~~2023~~ 2024 IRM






NYC [IRM = 19.9%, J LCR = 78.2%]
y = 0.6144x² - 24.7743x + 327.8550
R² = 0.9986
Locational Capacity Requirement (%)
Reserve Margin (%)
85
84
83
82
81
80
79
78
77
76
75
17
17.5
18
18.5
19
19.5
20
20.5
21
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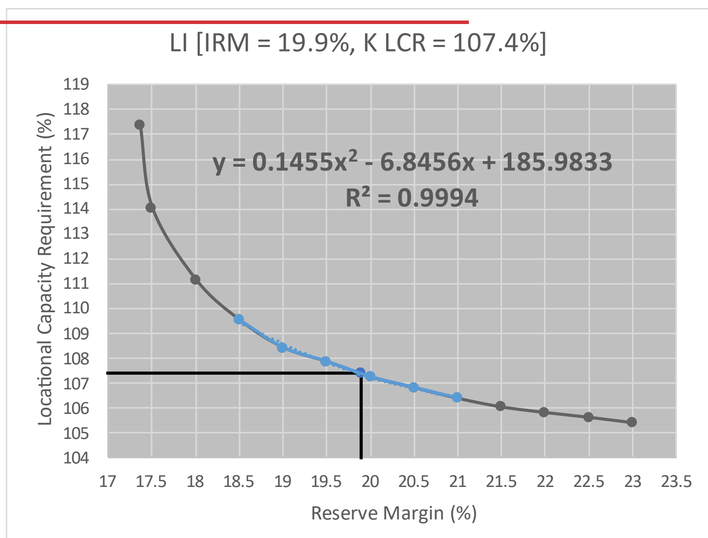
23.5


LI [IRM = 19.9%, K LCR = 107.4%]
y = 0.1455x² - 6.8456x + 185.9833
R² = 0.9994
Locational Capacity Requirement (%)
Reserve Margin (%)
119
118
117
116
115
114
113
112
111
110
109
108
107
106
105
104
17
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18
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4. Study Results – Base Case

Results of the NYSRC technical study show that the required NYCA IRM is ~~19.9~~23.1% for the ~~2023~~ 2024 Capability Year under base case conditions. Figure 3-2 on the previous page 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 ~~19.9~~23.1% for the ~~2023~~ 2024 Capability Year, together with corresponding initial LCRs of ~~78.2~~72.7 % and ~~107.4~~103.2% 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~~ 2024 IRM Study to ~~2022~~ 2023 IRM Study results (New York City LCR= ~~80.7~~78.2%, Long Island LCR= ~~99.8~~107.4%), the corresponding ~~2023~~ 2024 New York City initial LCR decreased by ~~2.5~~5.5%, while the corresponding Long Island LCR increased by ~~7.6~~4.2%. The primary driver for the increase in Long Island LCR was the ~~change in UDR elections~~reactivation of some of the peakers and the addition of offshore wind. The key factors in the reduction of the NYC LCR was the change in cable transition rates and the AC Transmission changes which allowed increased flows into NYC.

~~For the 2023-24 Capability Period LIPA made changes to its UDR elections over its controllable HVDC tie lines with PJM and ISONE (Neptune & Cross Sound Cable). A UDR is defined as a firm capacity purchase from a neighboring control area over a controllable HVDC line. An increase in firm power imports over a controllable HVDC line results in decreased tie line capacity to import emergency assistance which raises LI LCR. The specific details of LIPA UDR elections over its HVDC tie lines are market sensitive and confidential. The change for the Cross Sound Cable alone adds 330 MW, or roughly 6%, to the LCR requirement.~~

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.

For this analysis, the Base Case required 773 replications to converge to a standard error of 0.05 and required 2,577 replications to converge to a standard error of 0.025. For our cases, the model was run to 2,750 replications at which point the daily LOLE of 0.100 Event-Days/year for NYCA was met with a standard error less than 0.025. The confidence interval at this point ranges from 19.7% to 20.1%. It should be recognized that an IRM of 19.9% is in full compliance with the NYSRC Resource Adequacy rules and criteria (see Base Case Study Results section).

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5. Models and Key Input Assumptions

This section describes the models and related base case input assumptions for the 2024 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 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 13, 2023 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 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 NYCA summer peak load forecast of 31,765.6 MW was assumed in the 2024 IRM Study, a decrease of 480.4 MW from the forecast used in the 2023 IRM Study. This "Fall 2024 Summer Load Forecast" was prepared for the 2024 IRM Study by the NYISO staff in collaboration with the NYISO Load Forecasting Task Force and presented to the ICS on October 4, 2023. The 2024 forecast considered actual 2023 summer load conditions.

The peak load forecast changes are shown on Table 5-1 below. Relative to the 2023 IRM forecast, the load forecast for the 2024 IRM study has decreased in Zones A through I, 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 and 2024Actual and Forecast Coincident Peak Summer Loads (MW)

	Fall 2023Forecast	2023 Actual	2023 Normalized[7]	Fall 2024 Forecast	Forecast Change
	(a)	(b)	(c)	(d)	= (d) – (a)

[7] The "normalized" 2023 peak load reflects an adjustment of the actual 2023 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	13,703	15,114	15,515	-313
Zones J&K	16,418	15,020	16,284	16,251	-167
NYCA	32,246	28,723	31,398	31,766	-480

Use of the Fall 2024 Load Forecast resulted in an increase to the IRM compared to the 2023 IRM Study (Table 6-1).

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 include summer 2022 data, which was not included in prior LFU models. Zone F-J's response to weather in 2022 was lower in magnitude than it was in previous hot summers, while the magnitude is great in Zone A-E, and Zone K. This change has resulted in lower LFU impacts on the IRM than previous years. A sensitivity case shows that the modeling of LFU in the 2024 IRM Study has an effect of decreasing IRM requirements by 5.1% (Table 7-1, Case 3), as compared to a range of 7.6% 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 page 21.

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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 2024 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 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.[8] The LFU Phase 2 Study 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 was adopted in the base case of the 2023 IRM study and is also applied in the 2024 IRM study, with the 2013, 2017, and 2018 load shapes being adjusted to account for the expected 2024 BTM Solar penetration level.

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The NYISO will focus on model-based synthetic load shapes reflecting expected load patterns in the future, as well as dynamic winter LFU development, and BTM Solar modeling improvement, with the goal of implementation 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 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 DMNC ratings for existing facilities is seasonal tests required by procedures in the NYISO Installed Capacity Manual.

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There are no new thermal/conventional units planned in the 2024 IRM study. 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.

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 MW and a total host load of 148.8 MW, are included in this 2024 IRM Study. The full resource capacity of these BTM:NG

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

facilities is included in the NYCA capacity model, while their host loads are included in the NYCA 2024 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 2024. 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.

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 7,660 MW of NYCA renewable resources represented in the 2024 IRM Study.

It is projected that during the 2024 summer period there will be a total wind capacity of 2,502.3 MW participating in the capacity market in New York State. 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 IRM Study used available wind production data covering the years 2018 through 2022. 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. The NYISO obtained a consultant to develop synthesized historical offshore wind production profiles[9] based on the historical weather conditions in the areas along New York's shoreline. These synthesized production profiles covered the period between 2000-2021. The two new offshore wind resources in the 2024 IRM Study are modeled using the synthesized offshore wind production profiles for 2017 through 2021. In order capture the weather correlation between the offshore wind and the rest of the intermittent resources in GE-MARS simulation, the 2018-2021 offshore profiles are grouped with the same period as

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

other intermittent resources, and the 2017 offshore profile is grouped with the 2022 intermittent profiles.

Overall, inclusion of the projected 2502.3 MW of wind capacity in the 2024 IRM Study accounts for 7.2% of the 2024 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 103.3 MW and are included in the above total.

For the 2024 IRM study, 90 MW of utility level solar generation additions are included. The total NYS Bulk Power System (BPS) solar capacity in the 2024 IRM Study is 304.4 MW. Actual hourly solar plant output over the 2018-2022 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 NYSIO and GE developed the dynamic ELR functionality within the GE-MARS program and the recommended TC4C configuration in the ELR Whitepaper.[10] 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 IRM Study. The TC4C configuration contains a static time period limitation for the output from the ELR units. Starting with the 2024 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). In the 2024 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 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

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

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 2024 IRM Study covered the 2018-2022 period.

The weighted average five-year EFORd calculated for generating units in Zones A-I, and 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 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.

5.2.5 Emergency Operating Procedures (EOPs)

In the 2022 IRM Study, the need for SCR resources 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 SCR resources was further reduced to 6.9 days, due to the increased West Central Reverse Limit 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 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.

(2) 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 registration. For the month of July, the forecast SCR value for the 2024 IRM Study base case assumes that 1,281 MW will be registered, with varying amounts during other months based on historical experience. This is 56 MW higher than that assumed for the 2023 IRM Study.

As indicated above, the number of SCR calls in the 2024-2025 Capability Year 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 IRM Study is based on a recent analysis of performance data for the 2012-2022 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.3.9 for more details). All areas saw an increase in participation level, but the performance factor decreased for Zone A-F and Zone G-I, and therefore the updated SCR model had a minor impact on system reliability. Incorporation of SCR in the NYCA capacity model has the effect of increasing the IRM by 3.1% (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 SCR, the NYISO will implement several other types of EOP steps, such as voltage reductions, as required, to avoid or minimize customer disconnections. Projected 2024 EOP capacity values are based on recent actual data and NYISO forecasts.

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.

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

Commented [GB4]: Confirm value. Is this prior to the most recent updates to be presented at the 11/1 ICS?

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 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 2024 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,[11] 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 2024 IRM Study incorporates the confidential elections that these facility owners made for the 2024-2025 Capability Year. The Hudson Transmission Partners 660 MW HVDC Cable (HTP) 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.

UDRs, along with other cables captured in the IRM study are modeled with outage rate based on the average performance of their past 5-year's history. In the 2024 IRM Study, the cable performance for 2018-2022 is used to develop the outage rate assumptions. Aggregated cable outage rate is reduced from 7% to 4.5% for the 2024 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.

Commented [YH5]: I checked the calculation and these should be the complete list. Calculation spreadsheet is located here: \\hpcfs1.ad.aws1.nyiso.com\HPCCloud-Capacity\IRM\IRM24_data\PBC\Assumptions Matrix

I then notice that the original wording was from the AM - so we should keep in mind for updating AM in the future.

5.3 The Transmission Model[12]

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 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 IRM Study topology.

The transmission model assumptions included in the 2024 IRM Study are listed in Table A.10 in the Appendix which reflects changes from the model used for the 2023 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

- Central East voltage collapse limit increases from 2654 MW to 3885 MW; dynamic limits are also increased by the similar amount.
- Central East + Marcy Group limit is increased from 4260 MW to 5590 MW; dynamic limits are also increased by similar amount.

[11] *See* footnote 3 page 3

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

- UPNY-ConED limit increases from 6675 MW to 7050 MW.
- UPNY/SENY limit increases from 5250 MW to 7150 MW and dynamic limits are removed. However, due to the delay of the construction of Dover PAR, a reduction to this limit increase is modeled. To account for this delay, a conservative reduction of up to 750 MW from the 7150 MW limit for the UPNY/SENY is assumed for the 2024 IRM Study. Various scenarios of the UPNY/SENY transfer limit reduction have been tested and it was concluded that the transfer limit reduction on UPNY/SENY is not expected to impact the 2024 IRM Study results.

Update to Dysinger East and Zone A Group Limits

- Dysinger East limit decreased from 2200 MW to 2100 MW.
- Zone A group limit decreased from 2650 MW to 2500 MW.

Update to various Zone K Transfer Limits:

- Jamaca Ties import limit decreased from 320 MW to 305 MW.
- ConEd-LIPA import limit decreased from 1613 MW to 1598 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.

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 Transmission Owners (TOs) provided updated transition rates for their associated cable interfaces. Updated cable outage rates assumed in the 2024 IRM Study resulted in a 0.6% increase in the IRM compared with the 2023 IRM Study (Table 6-1).

As in all previous IRM studies, forced outage rates for overhead transmission lines were not represented in the 2024 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 2024 IRM could decrease by 2% (Table 7-1, Case 2).

The 2024 IRM Study included a modeling change to limit emergency assistance during severe and extreme conditions from neighboring jurisdictions 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 a means to reduce potential MW flow into NYCA at EOP steps during the GE MARS simulation. More details on this modeling change are discussed in section 5.2.5.

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 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[13] 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

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

and the Control Area's minimum IRM requirement, as well as the implementation of global EA limit of 3500 MW. For the past IRM studies, such EA assumption have reduced IRM requirements by approximately 6.2% (Table 7-1, Case 1).

For the 2024 IRM Study, an EOP whitepaper[14] 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 IRM Study, the 3,500 MW 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 Contral 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, included updated extra reserves data 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, 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 no errors with the data in the preliminary base case. A summary of these quality assurance reviews for the 2024 IRM Study input data is shown in Appendix A, Section A.4.

~~5. Models and Key Input Assumptions~~

~~This section describes the models and related base case input assumptions for the 2023 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 2023 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 14, 2022. Appendix A, Section A.3 provides more~~

[14] EOP Whitepaper: *****LINK****

Commented [BP6]: Based on the PBC without the new EA model

Commented [BP7R6]: 6.2% is without the EA model. It would be 7 with the new model

~~details of these models and assumptions and comparisons of several key assumptions with those used for this 2023IRM 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 2023 NYCA summer peak load forecast of 32,246 MW was assumed in the 2023 IRM Study, an increase of 107 MW from the forecast used in the 2022 IRM Study. This "Fall 2023 Summer Load Forecast" was prepared for the 2023 IRM Study by the NYISO staff in collaboration with the NYISO Load Forecasting Task Force and presented to the ICS on October 5, 2022. The 2023 forecast considered actual 2022 summer load conditions.~~

~~The peak load forecast change shown on Table 5-1 below, indicates a decrease in the peak loads for the upstate zones (zones A-I) and an increase in peak loads in Zone J. 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 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.~~

~~**Table 5-1**: Comparison of 2022 and 2023 Actual and Forecast Coincident Peak Summer Loads (MW)~~

	~~Fall 2022 Forecast~~	~~2022 Actual~~	~~2022 Normalized~~[15]	~~Fall 2023 Forecast~~	~~Forecast Change~~
	~~(a)~~	~~(b)~~	~~(c)~~	~~(d)~~	~~= (d) – (a)~~
~~Zones A-I~~	~~16,037~~	~~14,511~~	~~15,608~~	~~15,828~~	~~-209~~
~~Zones J&K~~	~~16,102~~	~~15,981~~	~~16,167~~	~~16,418~~	~~+316~~
~~NYCA~~	~~32,139~~	~~30,492~~	~~31,775~~	~~32,246~~	~~+107~~

~~Use of the Fall 2023 Load Forecast resulted in a negligible increase compared to the 2022 IRM Study (Table 6-1).~~

~~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. With the exception of Zone K, the load response to weather in 2021 was 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.~~

~~A sensitivity case shows that the modeling of LFU in the 2023 IRM Study has an effect of decreasing IRM requirements by 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% reduction in~~

~~[15] 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.~~

~~the IRM – see Table 6-1: Parametric IRM Impact Comparison – 2022 IRM Study vs. 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 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.[16] 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.~~

~~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.~~

~~5.2 The Capacity Model~~

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

~~Planned conventional generation facilities that are represented in the 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.~~

~~There are no new thermal/conventional units planned, and 1,205.2 MW of projected 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 Rule").~~

~~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 157.5 MW, are included in this 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 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 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.~~

~~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 7,413 MW of NYCA renewable resources represented in the 2023 IRM Study.~~

~~It is projected that during the 2023 summer period there will be a total wind capacity of 2,351.1 MW participating in the capacity market in New York State. This represents an increase in available wind resources of 539.3 MW and reflects the addition of five new wind resources. 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 2023 IRM Study used available wind production data covering the years 2017 through 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 2,351.1 MW of wind capacity in the 2023 IRM Study adds 6.1% to the 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 97.7 MW and are included in the above total.~~

~~For the 2023 study, there were 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 2017-21 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[17] the TC-4C configuration which was tested with~~

~~[17] 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~~

~~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 by 0.8% 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.~~

~~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 IRM Study covered the 2017-2021 period.~~

~~The weighted average five-year EFORd for generating units calculated for units in Zones G-I, J and K for the 2017-21 period is higher than the 2016-20 average value used for the 2022 IRM Study. This increase in average forced outage rates raises the IRM by 0.1% (Table 6-1). Appendix A, Figure A.5 depicts NYCA and Zonal five-year average EFORd trends from 2014 to 2021.~~

~~5.2.5 Emergency Operating Procedures (EOPs)~~

~~In the 2023 IRM Study, the West Central Reverse Limit was increased 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 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 6.9 Event-Days/year, which is consistent with the historical level.~~

(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 eroding operating reserves and to minimize expected loss of load. SCRs are modeled with monthly values based on July 2022 registration. For the month of July, the forecast SCR value for the 2023 IRM Study base case assumes that 1,225 MW will be registered, with varying amounts during other months based on historical experience. This is 61 MW higher than that assumed for the 2022 IRM Study.

As indicated above, the number of SCR calls in the 2023 Capability Year for the 2023 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 IRM Study is based on a recent analysis of performance data for the 2012-2021 period. This analysis determined a SCR overall performance factor of 69.9%. This is 0.3% higher than the performance factor used in the 2022 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.

Incorporation of SCR in the NYCA capacity model has the effect of increasing the IRM by 2.9% (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 SCR, the NYISO will implement several other types of EOP steps, such as voltage reductions, as required, to avoid or minimize customer disconnections. Projected 2023 EOP capacity values are based on recent actual data and NYISO forecasts.

In the 2023 IRM Study, the ICS implemented a modeling change recommended by the NYISO 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.[18] Maintaining 350 MW of 10-min operating reserve has

[18] 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

~~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.~~

~~Refer to Appendix B, Table B.2 for projected EOP frequencies for the 2023 Capability Year assuming the 20.2% 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 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 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[19], 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 IRM Study incorporates the confidential elections that these facility owners made for the 2023 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~~[20]

~~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 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 IRM Study topology.~~

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

[19] ~~*See* footnote 3 page 3~~
[20] ~~The transmission model is discussed in Appendix A Section 3.5~~

~~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 2,275 MW from 1,600 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 4,260 MW from 4,515 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 transformer returned to service on July 19, 2022 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 reduced to 420 MW from 515 MW~~
- ~~ConED-LIPA forward limit reduced to 135 MW from 220 MW~~
- ~~LI-WEST forward limit reduced 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~~

~~Forced transmission outages based on historic performance over the previous five years 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 IRM Study resulted in a 0.6% increase in the IRM compared with the 2022 IRM Study (Table 6-1).~~

~~As in all previous IRM studies, forced outage rates for overhead transmission lines were not represented in the 2023 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 IRM could decrease by 2% (Table 7-1, Case 2).~~

~~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 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 external 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%.[21]~~

~~In 2019, the ICS conducted an analysis of the IRM study's Outside Area Model to review its compliance with a NYSRC Policy 5-16 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.[22]~~

~~During the 2023 Capability Year, Hydro Quebec is expected to wheel 300 MW of capacity through NYCA to New England. In addition, the 2023 IRM study continues to limit the EA assistance to a maximum of 3,500 MW as applied in the previous five IRM Studies[23].~~

~~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% (Table 7-1, Case 1). This is 1% less than the impact determined in the 2022 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.~~

~~[21] *See* 2015 to 2022 IRM Study reports at www.nysrc.org/reports3.html.~~

~~[22] *See Evaluation of External Area Modeling in NYCA IRM Studies*, for a description of this analysis, at http://www.nysrc.org/reports3.html~~

~~[23] The 2018 IRM Study report, pages 17-18, describes this EA limit and its derivation. See www.nysrc.org/reports3.html.~~

~~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 2023 IRM Study input data is shown in Appendix A, Section A.4.~~

6. Parametric Comparison with 2022 IRM Study Results

The results of this ~~2023~~ 2024 IRM Study show that the final base case IRM result represents a ~~0.3~~3.2% increase from the ~~2022~~ 2023 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 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 the IRM impacts shown in Table 6-1 reflect the impacts from separate Tan45 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 ~~0.3~~3.2% IRM increase from the ~~2022~~ 2023 IRM Study. Table 6-1 also provides the reason for the IRM change for each study parameter from the ~~2022~~ 2023 IRM Study.

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 the AC Transmission topology 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 shapes caused a 0.13% increase.Lower DMNC ratings (Dependable Maximum Net Capability) in the downstate areas increased the IRM by 0.1%.

Seven parameter drivers in combination *decreased* the IRM from the 2022 base case by 1.59%. Of these seven drivers, the most significant was the update in the Behind-the-Meter (BTM) Solar profiles which decreased the IRM by 0.5%. Changes in the 2023 Load Forecasts (including the Fall Forecast),

Formatted: Normal, No bullets or numbering which resulted in a slight peak load increase across the system, resulted in a 0.20% reduction in the IRM. Modifications in the External Areas and the subsequent Policy-5 adjustments resulted in a 0.37% decrease in 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%.

~~There are seven parameter drivers that in combination *increased* the 2023 IRM from the 2022 base case IRM by 3.5%. 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 Unforced Capacity Deliverability Rights (UDR) elections caused a 0.5% increase. This was followed by updates of the outside areas including adjustments dictated by Policy 5-16 section 3.5.6 which ensure that the outside areas are no better than 0.1 Event-Days/year. This increased the IRM by 0.3%. Lower DMNC ratings (Dependable Maximum Net Capability) in the downstate areas 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.~~

~~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 Energy Limited Resource (ELR) modeling, which enabled greater targeting of their generation reduced the IRM by 0.8%. The lowering of several of the high load bins of the updated Load Forecast Uncertainty (LFU) model also resulted in a 0.6% IRM reduction. Topology updates, including restoration of the Neptune cable 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%~~

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

Table 6-1 Parametric IRM Impact Comparison 2023-2024

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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 Tan45 curve down and increased IRM.
Withholding Operating Reserves	0.25	0.18	0.25	0.19	Increase in OR 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	
2023 Load Forecast	-0.20	0.31	1.32	0.29	
External Data + Policy 5 Adjustment	-0.37	-0.21	-0.38	-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 Tan45 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

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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

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~~Table 6-1 Parametric IRM impact Comparison 2022 vs. 2023~~			
~~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 539.3 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~~	~~0.5~~	~~-~~	~~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~~	~~-~~	~~Increased the EFORd~~
~~Non-SCR and Non-OR EOPs~~	~~0.1~~	~~-~~	~~A decrease in EOP MW.~~
~~Total IRM Increase~~	~~3.5~~	~~-~~	~~-~~
~~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~~	~~-~~	~~Increased the availability of ELRs~~
~~New Summer LFUs~~	~~-0.6~~	~~-~~	~~Reduces the load forecast uncertainty~~
~~Topology Update + Neptune Rest.~~	~~-0.5~~	~~-~~	~~Increased 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~~	~~-~~	~~0.3~~	~~-~~
~~-~~	~~-~~	~~-~~	~~-~~
~~2023-24 IRM Study FBC~~	~~-~~	~~19.9~~	~~-~~

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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 ~~10~~ the various sensitivity cases. Note, Case 0 was the original Preliminary Base Case. All of the sensitivity cases are relative to that. Case 6a with the reduced Emergency Assistance (EA) from neighboring systems was then selected for the new base case and the resulting 23.1% IRM 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[24], 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[25]. 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. ~~Four of these cases show reasonable results when compared to past results.~~ 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.

~~The next three sensitivity cases, Cases 6, 7 and 8, illustrate the IRM impacts of 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.~~

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

[25] **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.

Case 6 examines the impact of reduced Emergency Assistance (EA) from neighboring systems based on the recommendations from the analysis in the EOP Whitepaper. Case 6b further reduced the winter limits to zero. As mentioned previously, Case 6a was subsequently selected as the new base case going forward. The various versions of Case 7 look at reducing winter capacity due to potential gas constraints. Finally, Case 8 looked at the impact of the delay on the installation of the Dover PAR. While some limits were affected the overall impact on the IRM was negligible. ~~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 evaluates the impact of deviating from the Policy 5-16 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. A reevaluation of the treatment of cable outage rates has been set as an ICS task for the first quarter of 2023.~~

Table 7-1: 2024 IRM Study - Sensitivity Cases

Case	Description	IRM (%)	NYC (%)	LI (%)	IRM (%) Change from Base	LOLH (hrs/yr)	EUE (MWh/yr)
0	2024 IRM Preliminary Base Case	20.8	72.7	109.9	-	0.33711	180.827
	These are the Base Case technical results derived from knee of the IRM-LCR curve						
1	NYCA Isolated	27.0	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						
2	No Internal NYCA transmission constraints	18.8	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	15.7	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	15.1	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	14.0	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	17.7	69.5	109.9	-3.1	0.31885	161.200

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	Shows sensitivity of IRM to SCR program

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	+2.2	0.36814	227.886
	Shows impact of modifying Emergency Assistance (EA) from neighboring areas modeled during the EOP steps in accordance with the EOP Whitepaper recommendation (Tan45)						
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						
7a-2	Winter Constraints plus S06a (7,000 MW)	23.1	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						
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						
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						
8	Dover PAR						

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	Shows impact of reducing AC Transmission transfer limits due to Dover PAR installation delay

~~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~~	~~19.9~~	~~-~~	~~0.358~~	~~192.4~~
~~*IRM Impacts of Key MARS Study Parameters*~~					
~~1~~	~~NYCA Isolated (No Emergency Assistance)~~	~~27.5~~	~~+7.6~~	~~0.315~~	~~141.1~~
~~2~~	~~No Internal NYCA Transmission Constraints~~	~~17.9~~	~~-2.0~~	~~0.373~~	~~275.5~~
~~3~~	~~No Load Forecast Uncertainty~~	~~11.7~~	~~-8.2~~	~~0.284~~	~~79.1~~
~~4~~	~~No Wind Capacity~~	~~13.8~~	~~-6.1~~	~~0.356~~	~~188.6~~
~~5~~	~~No SCR Capacity~~	~~17.0~~	~~-2.9~~	~~0.342~~	~~166.9~~
~~*IRM Impacts of Base Case Assumption Changes*~~					
~~6~~	~~Energy Limited Resource (ELR) (Fixed Output Shapes)~~	~~20.1~~	~~+0.2~~	~~0.365~~	~~194.7~~
~~7~~	~~Operating Reserves Not Maintained at Load Shedding~~	~~18.4~~	~~-1.5~~	~~0.357~~	~~186.6~~
~~8~~	~~Reverse New Load Shapes (Tan 45)~~	~~20.2~~	~~+0.3~~	~~0.365~~	~~167.0~~
~~9~~	~~Y49 Outage Extended Beyond June 2023~~	~~20.5~~	~~+0.6~~	~~0.352~~	~~168.7~~

~~10~~	~~Y49 Transition Rate Reverted to 2015-2019 Data~~	~~19.4~~	~~-0.5~~	~~0.358~~	~~210.6~~

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Concern has been expressed over the correlation of wind lulls, particularly between off-shore wind plants in New York and New England. In particular there was concern between the 800 MW Vineyard plant in ISONE and the new off-shore wind plant in Long Island. Further investigation showed that the Vineyard plant, which is currently under construction, was not included in the ISONE database. In order to investigate the impact further additional cases were run, the results of which are shown below in Table 7-2. The starting point was the original PBC with an IRM of 20.80%. The Vineyard plant was then added which caused both the NYISO and ISONE risk to drop below 0.1 event-days per year. When the NY LOLE was adjusted back to 0.1 event-days/year the IRM dropped to 20.69%. If the ISONE system was adjusted to be “no greater than 0.1” per Policy 5 requirements then the NY risk returned to the 0.10 event-days/year. Based on this analysis there was no net impact when an additional off-shore plant was added to ISONE and Policy 5 adjustments were made. This does not say that correlated outages are not important, but only that at existing penetration levels there does not seem to be any net impact when Policy 5 adjustments are taken into account. The correlation of wind lulls will continue to be an important area of focus as off-shore wind penetrations increase within NYISO and neighboring systems.

Table 7-2 Wind lull correlation analysis

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Results	STARTING Case	First Set: No Additional Policy 5 Adjustment		Second Set: With Additional Policy 5 Adjustment	
	2024 PBC	2024 PBC + 800 MW Vineyard	2024 PBC + 800 MW Vineyard @ 0.1	2024 PBC + 800 MW Vineyard + ISONE Policy 5 Adj of 275MW	2024 PBC + 800 MW Vineyard + ISONE Policy 5 Adj of 275 MW @ 0.1
IRM	20.80%	20.80%	20.69%	20.80%	20.80%
LOLE					
NYBA	0.1003	0.09763	0.09992	0.10007	0.10007
ISONE	0.10413	0.09225	0.09345	0.1035	0.1035

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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 ~~displaying~~ decrease slightly ~~steeper slope when following the trend of~~even though the required ICAP marginsincrease slightly. This is due to resources with below average performance being added to the system and the required UCAP is a function of required ICAP and the weighted average availability of system resources. Basically, when the EFORd goes up, because the UCAP is calculated as ICAP x (1-EFORd), the UCAP movement is more sensitive to the downward IRM movement—i.e., having a steeper slope than the IRM curve. Overall the *required* ICAP and UCAP remained roughly constant to last year although the *existing* ICAP decreased by about 4%.

Appendix C provides details of the ICAP to UCAP conversion.

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Figure 8-1 NYCA Reserve Margins