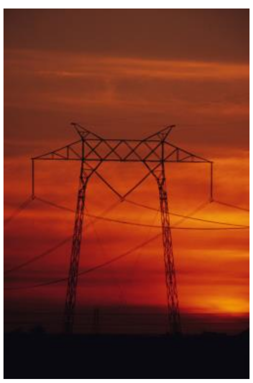
Technical Study Report

New York Control Area Installed Capacity Requirement

For the Period May 2019 to April 2020



December 7, 2018

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 following Capability Year,[1] including the development and approval of all modeling and database assumptions to be used in the reliability calculation process. This year's report covers the period May 2019 through April 2020 (2019 Capability Year).

Results of the NYSRC technical study show that the required NYCA IRM for the 2019 Capability Year is 16.8% under base case conditions. This IRM satisfies the NYSRC and Northeast Power Coordinating Council (NPCC) reliability criteria of a Loss of Load Expectation (LOLE) of no greater than 0.1 days per year. The base case, along with other relevant factors, will be considered by the NYSRC Executive Committee in December 2018 for its adoption of the Final NYCA IRM requirement for the 2019 Capability Year.

This study also determined corresponding *preliminary* Locational Capacity Requirements (LCRs) of 82.7% and 101.5% for New York City and Long Island, respectively. 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 using the NYSRC approved Final IRM that adheres to NYSRC Reliability Rules and Policies.

The 16.8% IRM base case value for the 2019 Capability Year represents a *1.4% decrease* from the 2018 base case IRM of 18.2%. Table 6-1 shows the IRM impacts of individual updated study parameters that result in this change. There are three parameter drivers that in combination *increased* the 2019 IRM from the 2018 base case by 0.7%. Of these three drivers, the principal driver is the addition of new wind generation with a total capacity of 158 MW and an updated wind shape model, which increased the IRM by 0.4%.

Ten parameter drivers in combination *decreased* the IRM from the 2018 base case by 2.1%. The largest decreases – 0.4% each – are attributed to an updated load forecast and load shapes and a reduction in generation fleet outage rates.

This study also evaluated IRM impacts of several sensitivity cases. The results of these sensitivity cases are summarized in Table 7-1, and in greater detail in Appendix B, Table B.1. In addition, a confidence interval analysis was conducted to demonstrate that there is a high confidence that

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

the base case 16.8% IRM will fully meet NYSRC and NPCC resource adequacy criteria that require a Loss of Load Expectation (LOLE) of no greater than 0.1 days per year.

The base case and sensitivity case IRM results, along with other relevant factors, will be considered by the NYSRC Executive Committee in adopting the final NYCA IRM requirement for 2019. The 2019 IRM Study also evaluated Unforced Capacity (UCAP) trends. UCAP is the manner by which the NYISO values installed capacity – considering the forced outage ratings of individual generating units. This analysis shows that required UCAP margins, which steadily decreased over the 2006-2012 period to 5%, have gradually increased to approximately 8% in the 2019 Capability Year (see Table 8-1).

1. Introduction

This report describes a technical study, conducted by the NYSRC Installed Capacity Subcommittee (ICS), for establishing the NYCA Installed Reserve Margin (IRM) for the period of May 1, 2019 through April 30, 2020 (2019 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:

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

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 2019 Capability Year.

The NYISO will implement the Final NYCA IRM as determined by the NYSRC, in accordance with the NYSRC Reliability Rules;[2] NYSRC Policy 5-13, *Procedure for Establishing New York Control Area Installed Capacity Requirement*;[3] the NYISO Market Administration and Control Area Services Tariff; and the NYISO Installed Capacity (ICAP) Manual.[4] 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 2019 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 2019 Capability Year (2019 IRM Study) are set forth in NYSRC Policy 5-13. The primary reliability criterion used in the IRM study requires a Loss of Load Expectation (LOLE) of no greater than 0.1 days per year for the NYCA. This NYSRC resource adequacy criterion is consistent with the Northeast Power Coordinating Council (NPCC) resource adequacy criterion. IRM study procedures include the use of two study methodologies: the *Unified Methodology* and the *IRM Anchoring Methodology.* The NYSRC reliability criterion and IRM study methodologies are described in Policy 5-13 and discussed in detail later in this report.

The NYSRC process for determining the IRM also identifies *preliminary* Locational Capacity Requirements (LCRs) for the New York City and Long Island localities. The LCR values determined

[2] http://www.nysrc.org/NYSRCReliabilityRulesComplianceMonitoring.asp
[3] http://www.nysrc.org/policies.asp
[4] http://www.nyiso.com/public/markets_operations/market_data/icap/index.jsp

in this 2019 IRM Study are considered *preliminary* because the NYISO, using a separate process – in accordance with NYISO tariff and procedures, while adhering to NYSRC Reliability Rules and NYSRC Sections 3.2 and 3.5 of Policy 5-13 – is responsible for setting *final* LCRs. For its determination of LCRs for the 2019 Capability Year, the NYISO will be utilizing a new economic optimization methodology.

The 2019 IRM Study was managed and conducted by the NYSRC Installed Capacity Subcommittee (ICS) and supported by technical assistance from NYISO staff.

Previous IRM Study reports, from year 2000 to year 2018, can be found on the NYSRC website.[5] Appendix C, Table C.1 provides a record of previous NYCA base case and final IRMs for the 2000 through 2018 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).

2. NYSRC Resource Adequacy Reliability Criterion

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

> *The NYSRC shall annually perform and document an analysis to calculate the NYCA installed Reserve Margin (IRM) requirement for the following Capability Year. The IRM analysis 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 day per year. This evaluation shall make due allowance for demand uncertainty, scheduled outages and de-ratings, forced outages and de-ratings, assistance over interconnections with neighboring control areas, NYS Transmission System transfer capability, and capacity and/or load relief from available operating procedures*.

This NYSRC Reliability Rule is consistent with NPCC Resource Adequacy Requirement 4 in Section 3.0 of NPCC Directory 1, *Design and Operation of the Bulk Power System*.

In accordance with NYSRC Reliability Rule A.2, *Establishing Load Serving Entity (LSE) Installed Capacity Requirements and Deliverable External Area Installed Capacity*, the NYISO is required to

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

establish LSE installed capacity requirements, including LCRs, for meeting the statewide IRM requirement established by the NYSRC for complying with NYSRC Reliability Rule A.1 above.

3. IRM Study Procedures

The study procedures used for the 2019 IRM Study are described in detail in NYSRC Policy 5-13, *Procedure for Establishing New York Control Area Installed Capacity Requirements*. Policy 5-13 also describes the computer program used for reliability calculations and the types of input data and models used for the IRM Study.

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

General Electric's Multi-Area Reliability Simulation (GE-MARS) is the primary computer program used for this probabilistic analysis. This program includes detailed load, generation, and transmission representation for eleven NYCA load zones — plus four external Control Areas (Outside World Areas) directly interconnected to the NYCA. The external Control Areas are: Ontario, New England, Quebec, and the PJM Interconnection. The eleven NYCA zones are depicted in Figure 3-1.[6] GE-MARS calculates LOLE, expressed in days per year, to provide a consistent measure of system reliability.[7] The GE-MARS program is described in detail in Appendix A, Section A.1.

Prior to the 2016 IRM Study, 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, were simulated using all hours in the year.

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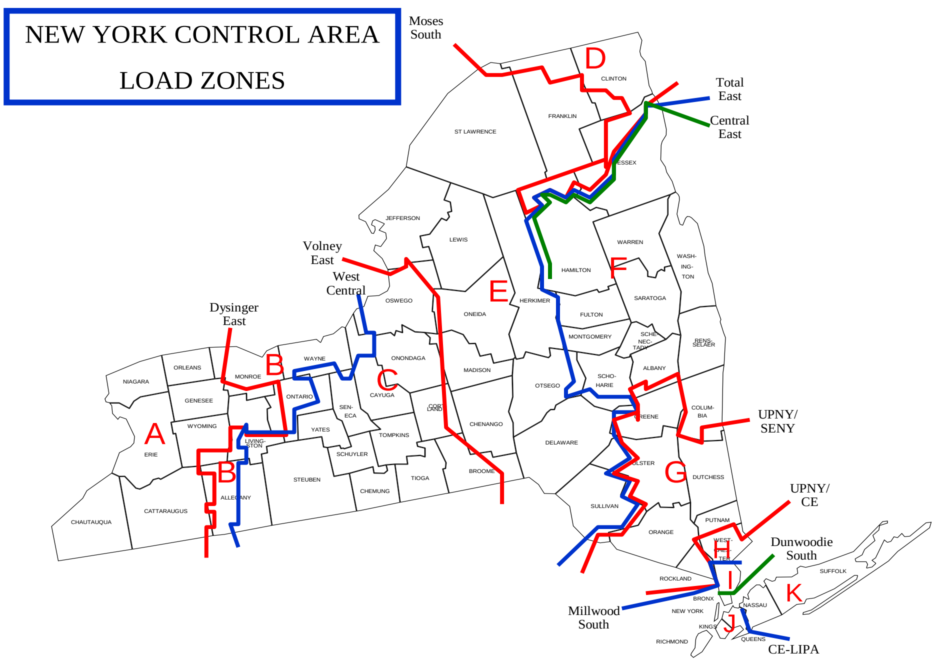
[6] The Federal Energy Regulatory Commission ordered the creation of a capacity zone within the NYISO's ICAP market encompassing Load Zones G, H, I, and J (the "G-J Locality"). The creation of the G-J Locality did not impact the current Unified and IRM Anchoring Methodologies and NYSRC's calculation of the NYCA IRM that is discussed in this report. The NYISO establishes the LCR for the G-J Locality.

[7] A change was adopted for the 2019 IRM Study to target the New York Balancing Area ("NYBA") to meet the LOLE criterion instead of NYCA, with the difference being that NYCA includes dummy zones for which MARS occasionally calculates loss of load events despite not containing load. The use of NYBA with the removal of dummy zones was recommended by the NYISO and GE and approved by ICS.

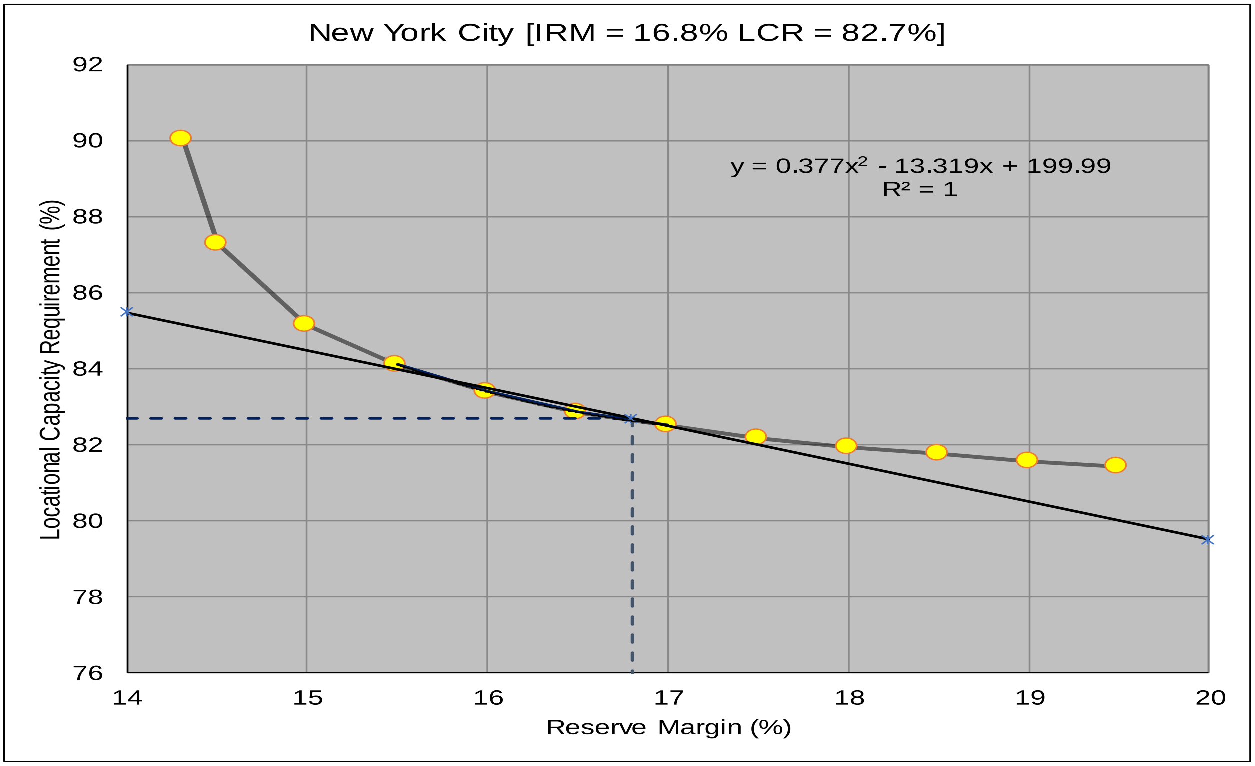
Using the GE-MARS program, a procedure is utilized for establishing NYCA IRM requirements (termed the *Unified Methodology*) which establishes a relationship between NYCA IRM and preliminary LCRs, as illustrated in Figure 3-2. All points on these curves meet the NYSRC 0.1 days/year LOLE reliability criterion described above. 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 5-13 provides a more detailed description of the Unified Methodology.

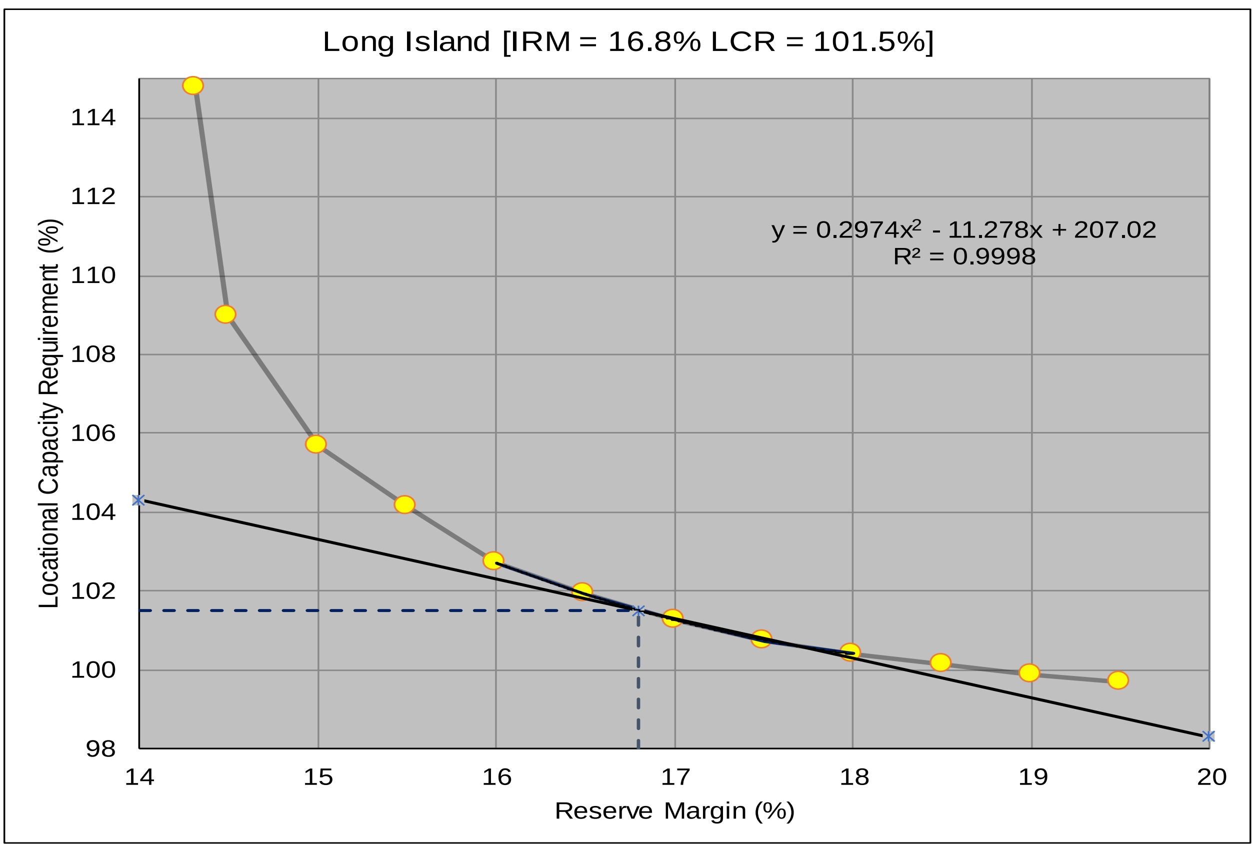
Figure 3-1 NYCA Load Zones



Base case NYCA IRM requirements and related preliminary LCRs 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 5-13 provides a more detailed description of the methodology for computing the Tan 45 inflection point.

Figure 3-2 Locational Requirements vs. Statewide Requirements





4. Study Results – Base Case

Results of the NYSRC technical study show that the required NYCA IRM is 16.8% for the 2019 Capability Year under base case conditions. Figure 3-2 on page 8 depicts the relationship between NYCA IRM requirements and resource capacity in NYC and LI.

The tangent points on these curves were evaluated using the Tan 45 analysis. Accordingly, maintaining a NYCA IRM of 16.8% for the 2019 Capability Year, together with corresponding preliminary LCRs of 82.7% and 101.5% for NYC and LI, respectively, will achieve applicable NYSRC and NPCC reliability criteria for the base case study assumptions shown in Appendix A.3.

Comparing the preliminary LCRs in this 2019 IRM Study to 2018 IRM Study results (NYC LCR=80.7%, LI LCR=103.2%), the preliminary 2019 NYC LCR increased by 2.0%, while the preliminary LI LCR decreased by 1.7%.

In accordance with NYSRC Reliability Rule A.2, *Load Serving Entity ICAP Requirements,* the NYISO is required to separately calculate and establish final LCRs. The most recent NYISO LCR study,[8] dated January 18, 2018, determined that for the 2018 Capability Year, the final LCRs for NYC and LI were 80.5% and 103.5%, respectively. An LCR Study for the 2019 Capability Year is scheduled to be completed by the NYISO in January 2019.

On October 5, 2018, FERC accepted proposed revisions to the methodology that the NYISO uses for determining LCRs[9]. The NYISO's previous methodology determined LCRs based on the Unified and Tan 45 methodologies[10] used by the NYSRC for calculating IRM requirements. The NYISO's new methodology utilizes an economic optimization algorithm to minimize the total cost of capacity for the NYCA. This new methodology will continue to maintain NYSRC's 0.1 days/year LOLE reliability standard while respecting the NYSRC-approved IRM. An LCR study for the 2019 Capability Year, scheduled to be completed by the NYISO in January 2019, will utilize the NYISO's new economic optimization methodology.

A Monte Carlo simulation error analysis shows that there is a 95% probability that the above base case result is within a range of 16.6% and 17.0% (see Appendix A.1.1) when obtaining a standard error of 0.025 per unit or less at 2,750 simulated years. This analysis demonstrates that there is

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[8] See *Locational Installed Capacity Requirements Study, http://www.nyiso.com/public/markets_operations/services/planning/planning_studies*

[9] The FERC Order accepting the NYISO tariff revisions can be found at: https://elibrary.ferc.gov/idmws/file_list.asp?document_id=14710049

[10] The Unified/Tan 45 methodology is described in Section 3.0.

a high level of confidence that the base case IRM value of 16.8% is in full compliance with the one day in 10 years LOLE criterion in NYSRC Reliability Rule A.1.

5. Models and Key Input Assumptions

This section describes the models and related input assumptions for the 2019 IRM Study. The models represented in the GE-MARS analysis include a *Load Model, Capacity Model, Transmission Model, and Outside World Model*. Potential IRM impacts of pending *Environmental Initiatives* and *Database Quality Assurance Review* are also addressed in this section. The input assumptions for the final base case were approved by the Executive Committee on October 12, 2018. Appendix A, Section A.3 provides more details of these models and assumptions and comparisons of several key assumptions with those used for the 2019 IRM Study.

5.1 Load Model

5.1.1 Peak Load Forecast

A 2019 NYCA summer peak load forecast of 32,488 MW was assumed in the 2019 IRM Study, a decrease of 380 MW from the 2018 summer peak forecast used in the 2018 IRM Study. This "Fall 2019 Load Forecast" was prepared for the 2019 IRM Study by the NYISO staff in collaboration with the NYISO Load Forecasting Task Force and presented to the ICS on October 3, 2018. This forecast considered actual 2018 summer load conditions. A 2018 "normalized" peak load[11] was determined to be 32,444 MW, 508 MW higher than the actual 2018 peak load and 424 MW lower than the fall forecast for 2018 (see Table 5-1 below for more details).

Table 5-1: Comparison of 2018 and 2019 Load Forecasts (MW) Used for IRM Studies

	Fall 2018 Forecast	2018 Actual	2018 Normalized	Fall 2019 Forecast	Forecast Change
Zones A-I	15,882	15,496	15,524	15,557	-325
Zones J&K	16,986	16,440	16,920	16,931	-55
NYCA	32,868	31,936	32,444	32,488	-380

Use of the fall 2019 peak load forecast and an updated load shape in the 2019 IRM Study decreased the IRM by 0.4% compared to the 2018 IRM Study (Table 6-1). This is due to the greater load decrease forecast for upstate (Zones A-I) in 2019 compared to the

[11] The "normalized" 2019 peak load reflects an adjustment of the actual 2918 peak load to account for the load impact of actual weather conditions, demand response programs, and muni self-generation.

downstate (Zones J&K) forecast load decrease (see Table 5-1). The NYISO will prepare a final 2019 summer peak forecast by the end of 2018 that will be used for the NYISO's calculation of Locality LCRs for 2019.

5.1.2 Load Forecast Uncertainty (LFU)

Some 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 LFU of individual NYCA areas, separate LFU models are prepared for four areas: New York City (Zone J), Long Island (Zone K), Westchester (Zones H and I), and the rest of New York State (Zones A-G).

There were no changes from the LFU models used for the 2018 IRM study based on data and analyses provided by the NYISO, Con Edison, and LIPA. Therefore, the LFU model used in the 2019 IRM Study did not change IRM requirements from the 2018 IRM Study. Appendix A, Section A.3.1 describes the LFU models in more detail.

5.1.3 Load Shape Model

A feature in GE-MARS that allows for the representation of multiple load shapes was utilized for the 2019 IRM Study. This multiple load shape feature enables a different load shape to be assigned to each of seven load forecast uncertainty bins. ICS has established criteria for selecting the appropriate historical load shapes to use for each of these load forecast uncertainty bins. For this purpose, a combination of load shape years 2002, 2006, and 2007 were selected as representative years. The load shape for the year 2007 was selected to represent a typical system load shape over the 1999 to 2017 period. The load shape for 2002 represents a flatter load shape, *i.e.*, a shape that has numerous daily peaks that are close to the annual peak. The load shape for 2006 represents a load shape with a small number of days with peaks that are significantly above the remaining daily peak loads. The combination of these load shapes on a weighted basis represents an expected probabilistic LOLE result.

5.2 Capacity Model

5.2.1 Planned New Non-Wind Generation, Re-ratings, Retirements, Deactivations, and Ineligible Capacity

Planned new non-wind facilities and retirements that are represented in the 2019 IRM Study are shown in Appendix A, Section A.3.2. 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.

A planned new generating unit, Arthur Kill Cogen, having a capacity of 11.1 MW, is included in the 2019 IRM Study. In addition, the ratings of several existing generating units increased by a total of 209.3 MW.

Also, the 2019 IRM Study reflected the deactivation of 399.2 MW of capacity from three existing generating units and 389.4 MW of ineligible ICAP from 10 existing units. No retirements were reflected in the study.

The NYISO has identified several state and federal environmental regulatory programs that could potentially impact operation of NYS Bulk Power System. A NYISO analysis concluded that these environmental initiatives would not result in NYCA capacity reductions or retirements that would impact IRM requirements during the 2019 Capability Year. For more details, see Appendix A, Section B.2.

A "BTM:NG" or behind the meter net generation program resource, for this study's purpose, contributes its full capacity while its entire host load is exposed to the electric system. Two BTM:NG resources with a total resource capacity of 150.0 MW and a total host load of 52.2 MW are included in 2019 IRM Study. The resource capacity of these BTM:NG facilities is included in the NYCA capacity model, while their host loads are included in the NYCA 2019 summer peak load forecast used for this study.

5.2.2 Wind Generation

It is projected that during the 2019 summer period there will be a total wind capacity of 1,892 MW participating in the capacity market in New York State. This includes 158 MW of planned new wind capacity. All wind farms are 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 2019 IRM Study used available wind production data covering the years 2013 through 2017. For new wind facilities, zonal hourly wind shape averages or the wind shapes of nearby wind units are modeled.

Overall, inclusion of the projected 1,892 MW of wind capacity in the 2019 IRM Study accounts for 4.8% of the 2019 IRM requirement (Table 7-1, Case 4). This relatively high IRM impact is a direct result of the relatively low capacity factor of wind facilities 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." A detailed summary of existing and planned wind resources is shown in Appendix A, Table A.7.

5.2.3 Generating Unit Availability

Generating unit forced and partial outages are modeled in GE-MARS by inputting a multi-state 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 2019 IRM Study covered the 2013-2017 period.

The weighted average five-year EFORd for NYCA thermal and large hydro generating units calculated for the 2013-2017 period is lower than the 2012-2016 average value used for the 2018 IRM Study. This decrease in forced outage rates reduced the 2019 IRM by 0.4% compared to the 2018 IRM Study (Table 6-1). Appendix A, Figure A.4 depicts NYCA EFORd trends from 2004 to 2017.

5.2.4 Emergency Operating Procedures (EOPs)

(1) Special Case Resources (SCRs)

SCRs are loads capable of being interrupted, and distributed generators that are rated at 100 kW or higher. SCRs are ICAP resources that provide load curtailment only when activated when as needed in accordance with NYISO emergency operating procedures. GE-MARS represents SCRs as an EOP step, which is activated to avoid or to minimize expected loss of load. SCRs are modeled with monthly values based on July 2018 registration. For the month of July, the forecast SCR value for the 2019 IRM Study base case assumes that 1,309 MW will be registered, with varying amounts during other months based on historical experience. The 2019 IRM Study had assumed a registered amount of 1,309 MW, 90 MW higher than that assumed for the 2018 IRM Study. The number of SCR calls in the 2019 Capability Year for the 2019 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 2019 IRM Study is based on performance data from 2012 through 2017. The SCR analysis for the 2019 IRM Study determined a SCR model value of 903 MW with an overall performance factor of 69.0%, 2.2% lower than the performance assumed in the 2018 IRM Study (refer to Appendix A, Section A.3.7 for more details). This lower SCR performance, together with the increase in the amount of registered SCRs, resulted in an IRM increase of 0.2% compared to the 2018 IRM Study (Table 6-1).

The 2019 IRM Study determined that for the base case, approximately 9.3 SCR calls would be expected during the 2019 Capability Period.

(2) Emergency Demand Response Program (EDRP)

The EDRP is a separate EOP step from the SCR Program that allows registered interruptible loads and standby generators to participate on a voluntary basis, and be paid for their ability to restore operating reserves after major emergencies have been declared. The 2019 IRM Study assumes that 5.5 MW of EDRPs will be registered in 2019, 10.5 MW lower than the amount assumed in the 2018 IRM Study. The 2019 EDRP capacity was discounted to a base case value of only one MW to reflect past performance. This value is implemented in the study in July 2019 and proportional to monthly peaks loads in other months, while being limited to a maximum of five EDRP calls per month. Both SCRs and EDRP are included in the Emergency Operating Procedure (EOP) model. Unlike SCRs, EDRPs are not ICAP suppliers and, therefore, are not required to respond when called upon to operate.

Incorporation of SCR and EDRP in the NYCA capacity model has the effect of increasing the IRM by 2.9% (Table 7-1, Case 5). This increase is because the overall availability of SCRs and EDRP is lower than the average statewide resource fleet availability.

(3) Other Emergency Operating Procedures

In addition to SCRs and the EDRP, the NYISO will implement several other types of EOPs, such as voltage reductions, as required, to avoid or minimize customer disconnections. Projected 2019 EOP capacity values are based on recent actual data and NYISO forecasts. Refer to Appendix B, Table B.2 for projected EOP frequencies for the 2019 Capability Year assuming the 16.8% base case IRM.

5.2.5 Unforced Capacity Deliverability Rights (UDRs)

The capacity model includes UDRs, which are capacity rights that allow the owner of an incremental controllable transmission project to provide locational capacity benefits. Non-locational capacity, when coupled with a UDR to deliver capacity to a Locality, can be used to satisfy locational capacity requirements. The owners of the UDRs elect whether they will utilize their capacity deliverability rights. This decision determines how this 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.

LIPA's 330 MW High Voltage Direct Current (HVDC) Cross Sound Cable, LIPA's 660 MW HVDC Neptune Cable, Hudson Transmission Partners 660 MW HVDC Cable, and the 315 MW Linden Variable Frequency Transformer are facilities that are represented in the 2019 IRM Study as having UDR capacity rights. 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 requirements. The 2019 IRM Study incorporates the confidential elections that these facility owners made for the 2019 Capability Year.

5.3 Transmission Model

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 transfer limits, is shown in Appendix A, Figure A.12. The transfer limits employed for the 2019 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 specifically for this cycle of the development of the topology. The assumptions for the transmission model included in the 2019 IRM Study are listed in the Appendix A, Tables A.7 and A.8 and Figure A.13, and described in detail in Appendix Section A.3.3.

Forced outages based on historic performance are represented in the GE-MARS model for the IRM study 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 are calculated based on the probability of occurrence from the failure rate and the time to repair. Transition rates into the different operating states for each interface were calculated based on the circuits comprising each interface, which includes failure rates and repair times for the individual cables, and for any transformer and/or phase angle regulator associated with that particular cable. Updated LIPA cable outage rates in the 2019 IRM Study reduced the IRM by 0.3% compared to the 2018 IRM Study, while updated Con Edison cable outage rates had no impact on the IRM (Table 6-1).

As in all previous IRM studies, forced outage rates for overhead transmission lines were not represented in the 2019 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 the NYC and LI Zones J and K. To illustrate the impact of transmission constraints on IRM, if there were no internal NYCA transmission constraints, the required 2019 IRM could decrease by 2.4% (Table 7-1, Case 2).

There are several topology changes for the 2019 IRM Study compared to the topology used in the 2018 IRM Study. These changes are:

1. **B and C Lines Out of Service**

   The B and C lines from PJM to Zone J are currently unavailable due to an extended forced outage. These lines are not expected to be returned to service in time for the 2019 Capability Year. As a result, the capability from PJM is estimated to be reduced from 315 MW on the grouped interface limit for the A, B, and C lines down to 105 MW and a zeroing of the individual B and C line total capability from 1,000 MW to 0 MW. An impact of removing the B and C lines during the 2019 Capability Year will be to increase the IRM by 0.2% (Table 7-1, Case 9).

2. **PAR on Line 33 Out of Service**

   The PAR controlling Line 33 from Ontario to Zone D is currently unavailable due to forced outage. This PAR is not expected to be returned to service in time for the 2019 Capability Year. A reduction in capability of 150 MW from Ontario to Zone D is estimated on the grouped interface limit leaving Ontario, which falls from 1,900 MW down to 1,750 MW, while the grouped interface entering Ontario is reduced from 1,650 MW down to 1,500

MW. The individual tie from Ontario to and from Zone D has been reduced from 300 MW down to 150 MW (both directions). The effects of this removal from service is being studied.

3. **<u>Other Modeling Changes</u>**

A review of the topology for this 2019 IRM Study found that the paths from the HTP and VFT dummy zones back to PJM were affecting the total transfer capability from PJM to Zone J. These dummy zones house the generation units in PJM that are contracted to supply capacity to New York. When forced outages occur on the lines entering Zone J the units were able to flow capacity back to PJM. This back flow increased the 2,000 MW grouped interface allowing more emergency assistance to be available to New York. The correction changes the return paths to circumvent the grouped interface.

These changes are described in detail in Appendix A, Section A.3.3.

5.4 Outside World Model

The Outside World Model consists of four interconnected external control areas contiguous with NYCA: Ontario, Quebec, New England, and the PJM Interconnection (PJM). NYCA reliability is improved and IRM requirements reduced by recognizing available emergency capacity assistance support from these neighboring interconnected control areas, in accordance with control area agreements governing emergency operating conditions. Representing all such external interconnection support arrangements in the 2019 IRM Study base case for permitting emergency assistance to NYCA would reduce the NYCA IRM requirements by 8.2% (Table 7-1, Case 1). This "reserve value of NYCA interconnections" compares to 8.0% in the 2018 IRM Study. The load and capacity and topology representation of neighboring control areas in the 2019 IRM Study was the same as used in the 2018 IRM Study. Further, this study incorporates the same Emergency Assistance Limit as used for the 2018 IRM Study that limits or caps available emergency assistance, which is discussed later in this section. The assumptions for the Outside World Model included in the 2019 IRM Study are listed in Appendix A, Tables A.12 and A.13.

The primary consideration for developing the base case load and capacity assumptions for the Outside World Areas is to avoid overdependence on these Areas for emergency assistance support. For this purpose, a rule from NYSRC Policy 5-13 is applied whereby an Outside World Area's LOLE cannot be lower than its own LOLE criterion. Therefore, for each of the Ontario, Quebec and New England control areas, a minimum LOLE of 0.1 days/year is modeled in accordance with NPCC requirements and the Areas' own individual resource adequacy criteria. For PJM, the 2019 IRM Study assumed a minimum LOLE of 0.14 day/year, which PJM uses for its planning studies. This is based on PJM's LOLE or resource adequacy criterion of 0.10 days/year, plus a PJM internal transmission constraint risk adder of 0.04 days/year. Also, each of these control areas' IRM can be no higher than that Area's minimum requirement.

In addition, NYSRC Policy 5-13 does not allow EOPs to be represented in Outside World Area models for providing emergency assistance to NYCA because of the uncertainties associated with the performance and availability of these resources.

Another consideration for developing models for the Outside World Areas is to recognize internal transmission constraints within those Areas that may limit emergency assistance into the NYCA. This recognition can be explicitly considered through direct multi-area modeling of well-defined external area "bubbles" and their internal interface constraints. The model representation explicitly requires adequate data to accurately model transmission interfaces, load areas, resource and demand balances, load shape, and coincidence of peaks among the load zones within these Outside World Areas. If adequate data is unavailable, the area can also be modeled implicitly either by aggregating bubbles and associated interfaces and reflecting the constraint limits at the interfaces between aggregated bubbles and at the NYCA border, or by increasing the LOLE of the Outside World Areas.

For this study, two Outside World Areas, New England and PJM, are each represented as multi-area models—*i.e.,* 13 zones for New England and five zones for the PJM Interconnection. These zonal representations align with these Control Areas' own models that they use for their reserve margin studies.

The existing PJM-SENY group transfer limit is imposed to reflect internal constraints in both the PJM and NYCA systems. The transmission model in IRM studies up through and including the 2016 IRM Study allowed for the contractual delivery of 1,000 MW at Waldwick and PJM re-delivery of 1,000 MW at the Hudson and Linden interface ("PJM wheel"). The PJM wheel was discontinued in 2017 and was replaced with changes in the NYISO-PJM Joint Operating Agreement which were incorporated in the 2018 and 2019 IRM studies.

As earlier discussed, excess generation capacity is delivered as emergency assistance from neighboring control areas to NYCA, recognizing interconnection limits, to avoid load shedding. As a result, the modeling of emergency assistance permits NYCA to operate at an IRM lower than otherwise required. In 2016, a concern was raised that calculated emergency transfer levels from neighboring control areas in prior GE-MARS studies may have been overstated compared to actual operating conditions. The concern is that a portion of the excess generation in the neighboring control areas, as identified by MARS as available to potentially provide emergency assistance, could actually be unavailable at the time when emergency assistance is needed by NYCA. In consideration of this concern, a study to examine issues related to the amount of emergency assistance that can be reasonably relied on was conducted by the NYISO in 2016. Building on the results of this study, ICS reviewed alternate models for representing emergency assistance. ICS determined that limiting total emergency assistance to a maximum of 3,500 MW (EA Limit), based on an analysis of total actual excess ten-minute operating reserves above required operating reserves in the four neighboring external areas, is appropriate.[12] This limit was applied in the 2018 IRM Study and again in this 2019 IRM Study. Elimination of the 3,500 MW EA Limit in the 2019 Study would have allowed additional emergency assistance, thereby decreasing the IRM by 0.3% (Table 7-1, Case 8).

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 (TOs) 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 TOs for their review. Also, certain confidential data are reviewed by two independent NYSRC consultants as required.

The NYISO, GE, and TO reviews found several minor data errors, none of which affected 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 2019 IRM Study input data is shown in Appendix A, Section A.4.

6. Parametric Comparison with 2018 IRM Study Results

The results of this 2019 IRM Study show that the base case IRM result represents a 1.4% decrease from the 2018 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 the 2018 IRM Study. The estimated percent IRM change for each parameter was calculated from the results of a parametric analysis in which a series of IRM studies were conducted to test the IRM impact of individual parameters. The IRM impact of each parameter in this analysis was normalized such that the net sum of the -/+ % parameter changes total the 1.4% IRM decrease from the 2018 IRM

[12] For more information about this analysis, refer to the NYSRC white paper, "MARS Emergency Assistance Modeling ", at http://www.nysrc.org/reports3.html.

Study. Table 6-1 also provides the reason for the IRM change for each study parameter from the 2018 IRM Study.

There are three parameter drivers that in combination *increased* the 2019 IRM from the 2018 base case by 0.7%. Of these three drivers, the principal driver is the addition of new wind generation with a total capacity of 158 MW and an updated wind shape model, which increased the IRM by 0.4%.

Ten parameter drivers in combination *decreased* the IRM from the 2018 base case by 2.1%. The largest decreases – 0.4% each – are attributed to an updated load forecast and load shapes and a reduction in generation fleet outage rates.

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

Table 6-1: Parametric IRM Impact Comparison– 2018 IRM Study vs. 2019 IRM Study

Parameter	Estimated IRM Change (%)	IRM (%)	Reasons for IRM Changes
2018 IRM Study – Final Base Case		**18.2**	
2019 IRM Study Parameters that increased the IRM			
Wind Units and Shapes for 2013-2017	+0.4		Two new wind units with lower than fleet average availability
Updated SCRs	+0.2		Decreased performance and Increased enrollment
NYCA Topology	+0.1		Cumulative effect of topology changes outside of the removal of the B and C lines (see below)
Total IRM Increase	**+0.7**		
2019 IRM Study Parameters that decreased the IRM			
Updated 2019 Load Forecast & Load Shapes	-0.4		Lower load forecasts especially downstate
Generator Transition Rates (EFORds) for 2013-2017	-0.4		Improved historic availability
LIPA Cable Transition Rates for 2013-2017	-0.3		Historical performance including the phasing out of a major outage on the Neptune line
Updated non SCR/EDRP EOPs	-0.3		Increase in 5% Voltage Reduction and voluntary load relief
Removal of B & C lines	-0.2		Causes increase in LCRs and slight lowering of IRM
Change Study Year	-0.1		Misalignment of renewable & load shapes
MARS 3.22.6	-0.1		Long term fix of seeding order issue
Use NYBA for LOLE criteria	-0.1		Removal of dummy zones from LOLE calc.
New Thermal Units & Rerates	-0.1		Lower EFORs on new & incremental units
Run of River Hydro Shapes for 2013-2017	-0.1		Dramatic increase in hydrological conditions for 2017
Total IRM Decrease	**-2.1**		
2019 IRM Study Parameters that did not change the IRM			
NYPA Sales 2019	0		
2018 Gold Book DMNC	0		
Maintenance 2019	0		
Con Ed Transition Rates (2013-2017)	0		
Net Change from 2018 Study		**-1.4**	
2019 IRM Study – Final Base Case		**16.8**	

7. Sensitivity Case Study

Determining the appropriate IRM requirement to meet NYSRC reliability criteria depends upon many factors. Variations from base case assumptions will, of course, yield different results. Table 7-1 shows IRM requirement results for selected sensitivity cases.

Sensitivity Cases 1 through 5 in Table 7-1 illustrate how the IRM would be impacted if certain major IRM study parameters were not represented in the IRM base case. The next set of cases – Cases 6 through 11 – illustrate IRM impacts recognizing that there is uncertainty associated with certain selected base case assumptions used in the 2019 IRM Study. These six cases change the base case assumptions to reasonable alternative values. NYSRC Executive Committee members may consider one or more of these sensitivity case results, in addition to the base case IRM and other factors, when the Committee develops the Final IRM for 2019 Capability Year.[13] The final sensitivity case – Case 12 – provides the IRM impact of a possible future system change that may occur beyond the 2019 Capability Period. This case has been conducted for informational purposes.

Appendix B, Table B-1 includes a more detailed description and explanation of each sensitivity case.

The methodology used to conduct sensitivity cases starts with the preliminary base case IRM results and adds or removes capacity from all NYCA zones until the NYCA LOLE approaches 0.1 days/year. Because of the lengthy computer run time and manpower needed to perform a full Tan 45 analysis in IRM studies, this method was applied for only Sensitivity Cases 9 and 11 in the 2019 Study. It should be recognized, therefore, that some accuracy is sacrificed when a Tan 45 analysis is not utilized.

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[13] See Section 5 of Policy 5-13 for a description of the process the NYSRC Executive Committee uses to establish the Final IRM.

Table 7-1: Sensitivity Cases – 2019 IRM Study

Case	Description	IRM (%)	% Change from Base Case
0	**2019 IRM Base Case**	16.8	0
	IRM Impacts of Key MARS Study Parameters		
1	NYCA isolated	25.0	+8.2
2	No internal NYCA transmission constraints	14.4	-2.4
3	No load forecast uncertainty	9.2	-7.6
4	No wind capacity	12.0	-4.8
5	No SCRs and EDRP	13.9	-2.9
	IRM Impacts of Assumption Uncertainties		
6	Remove CPV Valley from service	17.0	+0.2
7	Limit Emergency Assistance from PJM to NYCA to 1500 MW	16.8	0
8	Remove 3,500 MW Emergency Assistance Limit into NYCA	16.5	-0.3
9	Restore the B and C lines to service (tan 45)	17.0	+0.2
10	Remove Public Appeals from EOP Model	17.2	+0.4
11	Incorporate Quebec to New England wheel (tan 45)	17.1	+0.3
	IRM Impact of a Possible Future System Change		
12	Combine Cedars and Quebec Areas	16.9	+0.1

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 (UCAP) of individual units. To maintain consistency between the DMNC rating of a unit translated to UCAP and the statewide ICR, the ICR must also be translated to an unforced capacity basis. 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, any LCRs in place are also translated to equivalent UCAP values during these periods. The conversion to UCAP essentially translates from one index to another; it is not a reduction of actual installed resources. Therefore, no degradation in reliability is expected. The NYISO employs a translation methodology that converts ICAP requirements to UCAP in a manner that ensures compliance with NYSRC Resource Adequacy Rule A.1 (R1). The conversion to UCAP provides financial incentives to decrease the forced outage rates while improving reliability.

The increase in wind resources raises the IRM because wind capacity has a relatively lower peak period capacity factor than traditional resources. On the other hand, there is a negligible impact on the need for UCAP. Figure 8-1 below illustrates that required UCAP margins, which steadily decreased over the 2006-2012 period to about 5%, have gradually increased to approximately 8% in 2018. Appendix C provides details of the ICAP to UCAP conversion process used for this analysis.

Figure 8-1 NYCA Reserve Margins