WHITEMAN
OSTERMAN
& HANNA LLP

Attorneys at Law
www.woh.com

One Commerce Plaza
Albany, New York 12260
518.487.7600

Paul L. Gioia
Senior Counsel
518.487.7624 phone
pgioia@woh.com

December 21, 2018

Kimberly D. Bose
Secretary
Federal Energy Regulatory Commission
888 First Street, N.E.
Washington, DC 20426

Re: New York State Reliability Council, L.L.C.
Docket No. ____

Dear Secretary Bose:

Pursuant to Section 3.03 of the New York State Reliability Council Agreement ("NYSRC Agreement"),[1] the New York State Reliability Council, L.L.C. ("NYSRC") hereby submits this filing to advise the Federal Energy Regulatory Commission ("Commission") that the NYSRC has revised the Installed Capacity Requirement ("ICR") for the New York Control Area ("NYCA") for the period beginning on May 1, 2019 and ending on April 30, 2020 ("2019-2020 Capability Year"). The NYSRC respectfully requests that the Commission accept and approve the NYSRC's filing effective no later than February 15, 2019, so that the revised ICR may be in place for the installed capacity

[1] The NYSRC Agreement is available on the NYSRC website, www.nysrc.org, under Documents/Agreements.

auction to be conducted by the New York Independent System Operator, Inc. ("NYISO") on March 28, 2019. The NYISO has informed the NYSRC that it needs the period between February 15, 2019 and March 28, 2019 to: (i) determine, in conjuction with the NYISO's Operating Committee, the Locational Capacity Requirements for the three Localities in the New York Control Area ("NYCA"): New York City (NYISO Zone J), Long Island (NYISO Zone K), and the nested Locality of NYISO Zones G through J; (ii) define capacity import rights for the coming year; (iii) inform load serving entities ("LSEs") of their minimum capacity requirements for capacity procurement in the NYISO's auctions; and (iv) make other preparations for the March 28, 2019 capacity auction. The NYSRC also respectfully requests that the Commission grant any and all waivers of its regulations that it deems necessary to accept and approve the filing effective no later than February 15, 2019.

I. Summary

On December 7, 2018, the NYSRC Executive Committee adopted a required Installed Reserve Margin ("IRM") of 17.0% for the NYCA for the 2019-2020 Capability Year. The Executive Committee's decision was based on a technical study, the New York Control Area Installed Capacity Requirement for the Period May 2019 through April 2020, Technical Study Report ("2019 IRM Study" or "Study") dated December 7, 2018, and other relevant factors. The 2019 IRM Study results indicate that, under base case conditions, a NYCA IRM for the 2019-2020 Capability Year of 16.8% would satisfy the NYSRC's resource adequacy criteria, set forth in the NYSRC's Reliability Rule A.1, Requirement R1. After considering the 2019 IRM Study, the results of various sensitivity studies which resulted in IRMs both higher and lower than the base case IRM,

and other relevant factors, the NYSRC Executive Committee determined that an IRM of 17.0% would meet the applicable resource adequacy criteria for the 2019-2020 Capability Year. A copy of the Study is attached hereto as Attachment A, and the resolution adopted by the Executive Committee with respect to its IRM determination is attached hereto as Attachment B. The 2019 IRM Study may be found on the NYSRC website, www.nysrc.org, under Documents/Reports.

Since the 17.0% IRM for the 2019-2020 Capability Year adopted by the NYSRC represents a change from the 18.2% IRM approved for the 2018-2019 Capability Year, Commission approval of the filing is required under Section 3.03 of the NYSRC Agreement. The NYSRC requests that the Commission accept and approve this filing and the revised IRM effective no later than February 15, 2019 so that the revised IRM is in place for the installed capacity auction to be conducted by the NYISO on March 28, 2019.

II. Background

The NYSRC was approved by an order issued by the Commission in 1998,[2] and subsequent Commission orders,[3] as part of the restructuring of the electricity market in New York State and the formation of the NYISO. In its orders, the Commission approved the NYSRC Agreement among the members of the New York Power Pool ("NYPP"), which established the NYSRC and described its responsibilities, and the

---

[2] *Cent. Hudson Gas & Elec. Corp.*, *et al.*, 83 FERC ¶ 61,352 (1998), *order on reh'g*, 87 FERC ¶ 61,135 (1999).

[3] *Cent. Hudson Gas & Elec. Corp.*, *et al.*, 86 FERC ¶ 61,062 (1999); *Cent. Hudson Gas & Elec. Corp.*, *et al.*, 87 FERC ¶ 61,135 (1999); *Cent. Hudson Gas & Elec. Corp., et al.*, 88 FERC ¶ 61,138 (1999).

NYISO/NYSRC Agreement between the NYISO and the NYSRC,[4] which established the relationship between the NYISO and the NYSRC and their respective responsibilities.

One of the responsibilities assigned to the NYSRC is the establishment of the annual statewide ICR for the NYCA.[5] Section 3.03 of the NYSRC Agreement reads as follows:

> The NYSRC shall establish the state-wide annual Installed Capacity requirements for New York State consistent with NERC [North American Electric Reliability Council] and NPCC [Northeast Power Coordinating Council] standards. The NYSRC will initially adopt the Installed Capacity requirement as set forth in the current NYPP Agreement and currently filed with FERC. Any changes to this requirement will require an appropriate filing and FERC approval. In establishing the state-wide annual Installed Capacity requirements, consideration will be given to the configuration of the system, generation outage rates, assistance from neighboring systems and Local Reliability Rules.

The ICR is described generally in terms of an installed reserve margin or IRM.[6] The NYISO was assigned the responsibility of determining the installed capacity obligations of LSEs and establishing locational capacity requirements ("LCRs") needed to ensure that the statewide ICR is met.[7] The responsibilities assigned by the NYSRC Agreement and the NYISO/NYSRC Agreement are implemented in the NYSRC's Reliability Rules, the NYSRC's Policy No. 5-13, Procedure for Establishing New York

---

[4] The NYISO/NYSRC Agreement is available on the NYSRC website, www.nysrc.org, under Documents/Agreements.

[5] NYSRC Agreement § 3.03; NYISO/NYSRC Agreement § 4.5.

[6] The annual statewide ICR is established by implementing NYSRC Reliability Rules for providing the corresponding statewide IRM requirements. The IRM requirements relates to ICR through the following equation: ICR = (1+ IRM Requirement) x Forecasted NYCA Peak Load (NYSRC Reliability Rules, A. Resource Adequacy, Introduction).

[7] NYISO/NYSRC Agreement § 3.4; NYISO Services Tariff §§ 5.10 and 5.11.4.

Control Area Installed Capacity Requirements,[8] and the NYISO's Market Administration and Control Area Services Tariff ("Services Tariff").

A. NYSRC Reliability Rules

The NYSRC Reliability Rules & Compliance Manual, Section 2.A, Resource Adequacy, Introduction,[9] provides that among the factors to be considered by the NYSRC in setting the annual statewide IRM are the characteristics of the loads, uncertainty in the load forecast, outages and deratings of generating units, the effects of interconnections to other control areas, and transfer capabilities within the NYCA.

Reliability Rule A.1, Establishing NYCA Installed Reserve Margin Requirements, Requirement R1, is consistent with the NPCC resource adequacy criterion. It provides that:

> **R1.** 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:
>
> > **R1.1** 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 days per year. This evaluation shall make due allowances for *demand* uncertainty, scheduled outages and deratings, forced outages and deratings, assistance over interconnections with neighboring *control areas*, *emergency NYS Transmission System transfer capability*, and *capacity and/or load relief* from available *operating procedures*.

Reliability Rule A.2, Establishing Load Serving Entity Installed Capacity Requirements, Requirement R1, provides that:

---

[8] NYSRC Policy 5-13 is available on the NYSRC website, www.nysrc.org, under Documents/Policies.

[9] The NYSRC Reliability Rules are available on the NYSRC website, www.nysrc.org, under Documents/NYSRC Reliability Rules & Compliance Monitoring.

R1. The *NYISO* shall annually establish *Load Serving Entity* (LSE) *installed capacity* (ICAP) requirements, including *Locational Capacity Requirements* (LCRs), in accordance with *NYSRC* rules and *NYISO* tariffs. *NYISO* analyses for setting LCRs shall include the following requirements:

> **R1.1** The *NYISO* LCR analysis shall use the IRM established by the *NYSRC* as determined in accordance with Reliability Rule A.1.
>
> **R1.2** The *NYISO* LCR analysis shall maintain a LOLE of 0.1 days/year, as specified by the Requirement A.1: R1.1.
>
> **R1.3** The *NYISO* LCR analysis shall use the software, load and capacity data, and models consistent with that utilized by the NYSRC for its determination of the IRM, as described in Sections 3.2 and 3.5 of NYSRC Policy 5, "Procedure for Establishing NYCA Installed Capacity Requirements."
>
> **R1.4** The *NYISO* shall document the procedures used to calculate the LCRs.
>
> **R1.5** The *NYISO* shall prepare a report for the next *Capability Year* describing the analyses for establishing (1) *LSE ICAP* requirements, and (2) LCRs for applicable *NYCA zones*, prepared in accordance with R1.1 through R1.3.

B. NYSRC Policy No. 5-13, Procedure for Establishing New York Control Area Installed Capacity Requirements

The last paragraph of the Introduction of NYSRC Policy No. 5-13 provides that:

> The final NYCA IRM requirement, as approved by the NYSRC Executive Committee, is the basis for various installed capacity analyses conducted by the NYISO. These NYISO analyses include the determination of the capacity obligation of each Load Serving Entity (LSE) on a Transmission District basis, as well as Locational Installed Capacity Requirements, for the following capability year. These NYISO analyses are conducted in accordance with NYSRC Reliability Rules and Procedures.

Section 2.2 of NYSRC Policy No. 5-13, "Timeline," provides a timeline for establishing the statewide IRM. This timeline is based on the NYSRC providing the NYISO with next year's NYCA IRM requirement in December, when the NYISO, under its installed capacity and procurement process, is required to begin its studies for determining the following summer's LSE capacity obligations.

Section 4.4 of NYSRC Policy No. 5-13, "NYSRC Executive Committee," sets forth the process for approval of the annual statewide IRM by the NYSRC Executive Committee as follows:

> The NYSRC Executive Committee has the responsibility of approving the final IRM requirements for the next capability year.
>
> - Review and approve preliminary and final base case assumptions and models for use in IRM Study.
> - Review preliminary base case IRM results.
> - Approve sensitivity studies to be run and their results.
> - Review and approve IRM Study prepared by ICS [Installed Capacity Subcommittee].
> - Establish and approve the final NYCA IRM requirement for the next capability year (see Section 5).
> - To the extent practicable, ensure that the schedule for the above approvals allow that the timeline requirements in Section 2.2 are met.
> - Notify the NYISO of the NYCA IRM requirements and meet with NYISO management as required to review IRM Study results.
> - Make IRM Study results available to state and federal regulatory agencies and to the general public by posting the study on the NYSRC Web site.

III. Communications

The names, titles, mailing addresses, and telephone numbers of those persons to whom correspondence and communications concerning this filing should be addressed are as follows:

Herbert Schrayshuen
Executive Secretary
New York State Reliability Council, LLC
4408 Jack-in-the Pulpit Circle
Manlius, NY 13104

Roger Clayton
Chairman
New York State Reliability Council, LLC
3055 Ennis Road
Pattersonville, NY 12137
Email:
roger.clayton@electricpowerresoirces.com

Paul L. Gioia
Counsel to the New York State
Reliability Council, LLC
Whiteman Osterman & Hanna LLP
One Commerce Plaza,
Albany, NY 12260
Telephone: (518) 487-7624
Email: pgioia@woh.com

IV. Adoption of IRM for the 2019-2020 Capability Year

A. 2019 IRM Study

The 2019 IRM Study was conducted by the NYSRC to determine the statewide IRM necessary to meet NYSRC and NPCC reliability criteria within the NYCA during the period from May 1, 2019 through April 30, 2020. The reliability calculation process for determining the NYCA IRM requirement utilizes a probabilistic approach. This technique calculates the probabilities of outages of generating units, in conjunction with load and transmission models, to determine the number of days per year of expected capacity shortages. The General Electric Multi-Area Reliability Simulation ("GE-MARS") is the primary computer program used for this probabilistic analysis. The result of the calculation for loss of load expectation ("LOLE") provides a consistent measure of

electric power system reliability. Computer runs for the 2019 IRM Study were performed by NYISO staff at the request and under the guidance of the NYSRC. The GE-MARS model includes a detailed load and generation representation of the eleven NYCA zones as well as the four external control areas ("Outside World Areas") interconnected to the NYCA. The GE-MARS program also uses a transportation model representing transmission that reflects the ability of the system to transfer energy between zones under probabilistic generation and load scenarios. This technique is commonly used in the electric power industry for determining installed reserve requirements.

The 2019 IRM Study continues to implement two study methodologies, the Unified and the IRM Anchoring Methodologies. These methodologies are discussed in the 2019 IRM Study (at pages 6 and 7) under the heading, "IRM Study Procedures." These methodologies are discussed in greater detail in Appendices A and B of Policy 5-13.

The 2019 IRM Study also evaluates IRM requirement impacts caused by the updating of key study assumptions and various sensitivity cases.[10] The comparison with the 2018 base case IRM is depicted in Table 6-1 at page 21 of the Study. The results of the sensitivity cases are set forth in Table 7-1 at page 23 of the Study and in Table B-1 at pages 46 and 47 in Appendix B of the Study. The base case results, the sensitivity cases, and other relevant factors provided the basis for the NYSRC Executive Committee

[10] The NYSRC Executive Committee approved the assumptions used in the 2019 IRM Study base case on July 13, 2018, and approved revised assumptions on October 12, 2018. The sensitivity cases for the 2019 IRM Study were approved by the NYSRC Executive Committee on December 7, 2018. The assumptions used in the Study are set forth in Appendix A of the Study in Table A.3 on page 10, Table A.5 on page 12, Table A.7 on page 18, Table A.9 on page 34, and Table A.11 on page 35.

determination to adopt a 17.0% NYCA IRM requirement for the 2019-2020 Capability Year.

Definitions of certain terms in the 2019 IRM Study can be found in the Glossary, Appendix D of the Study.

B. 2019 Study Base Case Results

The base case for the 2019 IRM Study calculated the NYCA IRM requirement for the period May 1, 2019 through April 30, 2020 to be 16.8% under base case conditions.[11] The 2019 base case result of 16.8% is 1.4 percentage points lower than the 18.2% base case IRM requirement determined by the 2018 IRM Study.

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 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

[11] There is a 95% probability that the IRM is within a range from 16.6% to 17.0% based on a standard error of 0.025 per unit at 2,500 simulated years. *See* Appendix A of the Study, A.1.1, page 8, Error Analysis.

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 on page 21 of the Study, set forth below, shows the IRM impact of individual updated study parameters that resulted in this change from the 2018 base case IRM.

Parametric Comparison with 2018 IRM Study Results

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**	

After considering the 2019 IRM Study results, the modeling and assumption changes made to simulate actual operating conditions and system performance, the numerous sensitivity studies, which resulted in IRMs higher and lower than the base case IRM, and based on its experience and expertise, on December 7, 2018, the NYSRC Executive Committee adopted an IRM of 17.0% for the 2019-2020 Capability Year.

V. Effective Date

The NYSRC respectfully requests that the Commission accept and approve this filing effective no later than February 15, 2019, so that the revised statewide ICR may be in place in time for the NYISO installed capacity auction for the summer capability period from May 1, 2019 through October 31, 2020. The auction is scheduled to take place on March 28, 2019. The NYISO has advised the NYSRC that in order for the new ICR to be reflected in the summer capability period auction, both the NYISO and its market participants should be informed of the newly established IRM by no later than February 15, 2019. In order to provide adequate notice to the NYISO, the NYSRC respectfully requests that the Commission act in an expedited manner to accept and approve this filing effective no later than February 15, 2019. The NYSRC also respectfully requests that the Commission grant any and all waivers of its regulations that it deems necessary to allow the Commission's acceptance and approval of the filing to be effective no later than that date.

VI. Contents of the Filing

The following documents are being submitted for filing:

- This transmittal letter;
- A copy of the NYSRC 2019 IRM Study (Attachment A); and

- A copy of the NYSRC resolution adopting the revised IRM for the 2019-2020 Capability Year (Attachment B).

VII. Conclusion

WHEREFORE, in view of the foregoing, the NYSRC respectfully requests that the Commission accept and approve the NYSRC's filing effective no later than February 15, 2019, and grant any and all waivers of its regulations that it deems necessary to accept and approve the filing effective no later than February 15, 2019.

Respectfully submitted,

/s/ Paul L. Gioia

Paul L. Gioia
Counsel to the New York State Reliability Council, L.L.C.

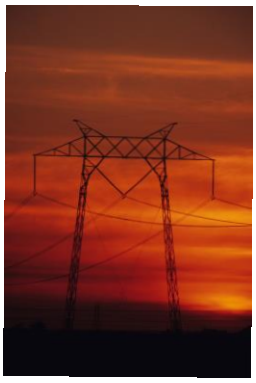
ATTACHMENT A

NYSRC 2019 IRM Study and Appendices

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.

Table of Contents

Executive Summary 2

1. Introduction 4
2. NYSRC Resource Adequacy Reliability Criterion 5
3. IRM Study Procedures 6
4. Study Results – Base Case 9
5. Models and Key Input Assumptions 10

5.1 Load Model 10

5.1.1 Peak Load Forecast 10

5.1.2 Load Forecast Uncertainty (LFU) 11

5.1.3 Load Shape Model 11

5.2 Capacity Model 11

5.2.1 Planned New Non-Wind Generation, Reratings, ... 11

Retirements, Deactivations, and Ineligible Capacity 11

5.2.2 Wind Generation 12

5.2.3 Generating Unit Availability 13

5.2.4 Emergency Operating Procedures (EOPs) 13

5.2.5 Unforced Capacity Deliverability Rights (UDRs) 15

5.3 Transmission Model 15

5.4 Outside World Model 17

5.5 Database Quality Assurance Review 19

6. Parametric Comparison with 2019 IRM Study Results 19
7. Sensitivity Case Study 22
8. NYISO Implementation of the NYCA Capacity Requirement 23

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.

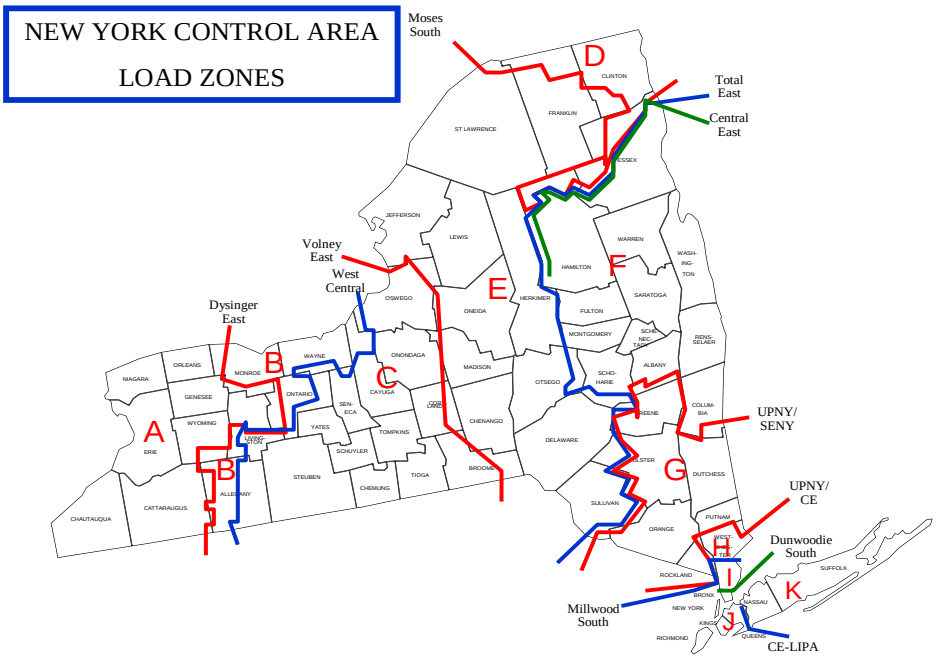
Prior to the 2016 IRM Study, IRM, base case, and sensitivity analyses were simulated using only weekday peak loads rather than evaluating all 8,760 hours per year in order to reduce computational run times. However, the 2016 IRM Study determined that the difference between study results using the daily 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.

[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.

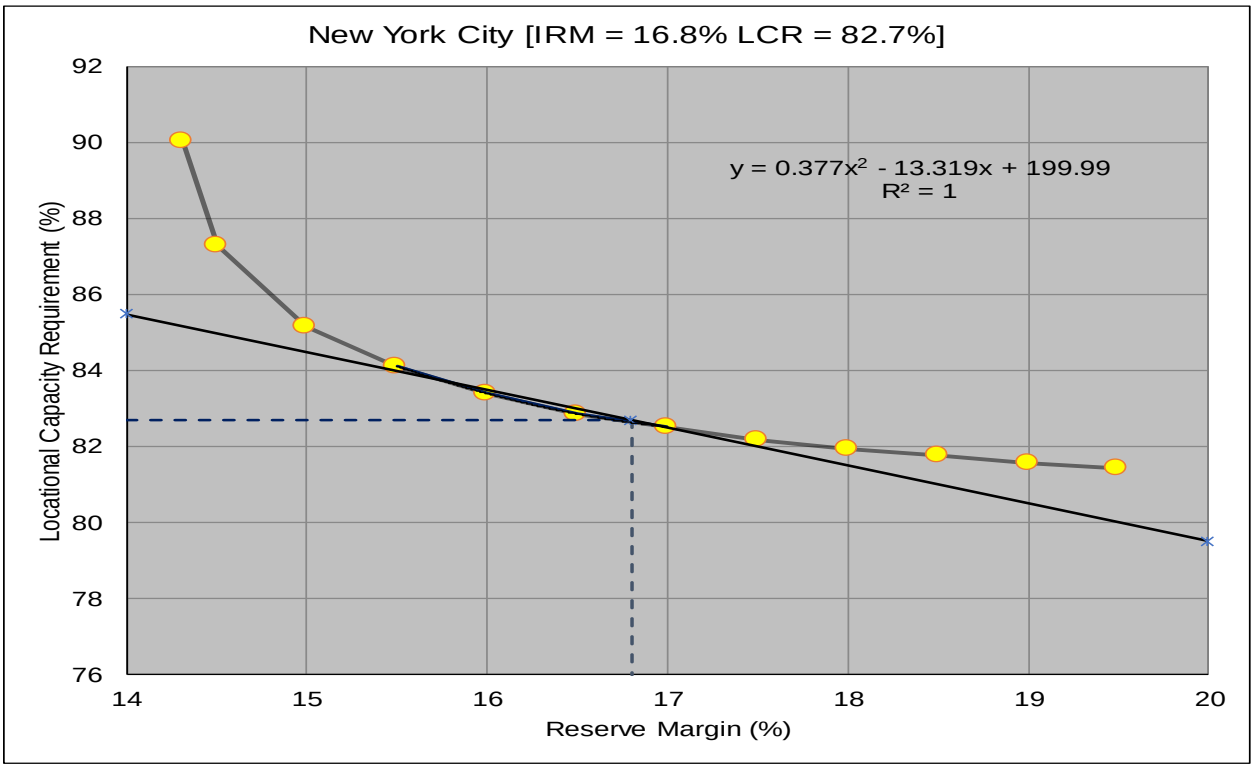
Using the GE-MARS program, a procedure is utilized for establishing NYCA IRM requirements (termed the *Unified Methodology*) which establishes a relationship between NYCA IRM and preliminary LCRs, as illustrated in Figure 3-2. All points on these curves meet the NYSRC 0.1 days/year LOLE reliability criterion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

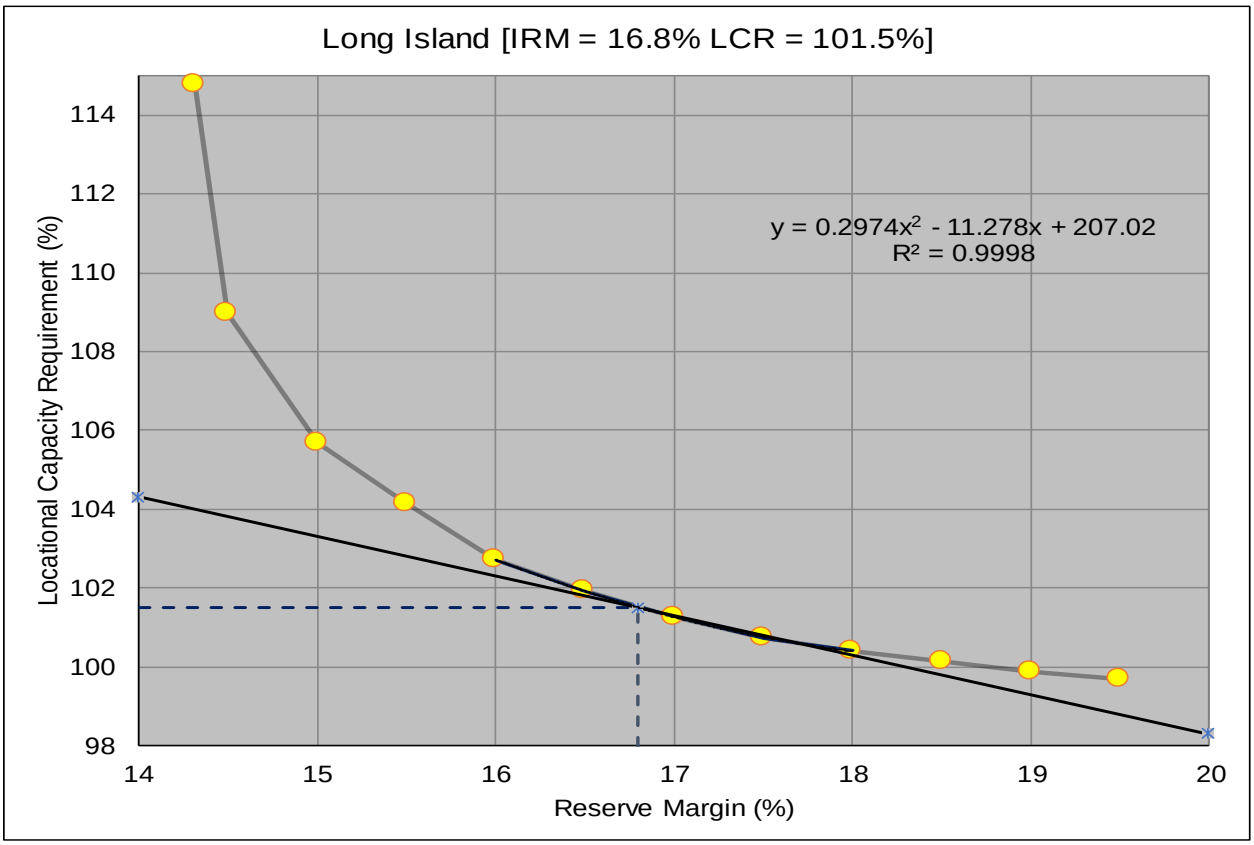
Figure 3-1 NYCA Load Zones



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

[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. **Other Modeling Changes**

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.

[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

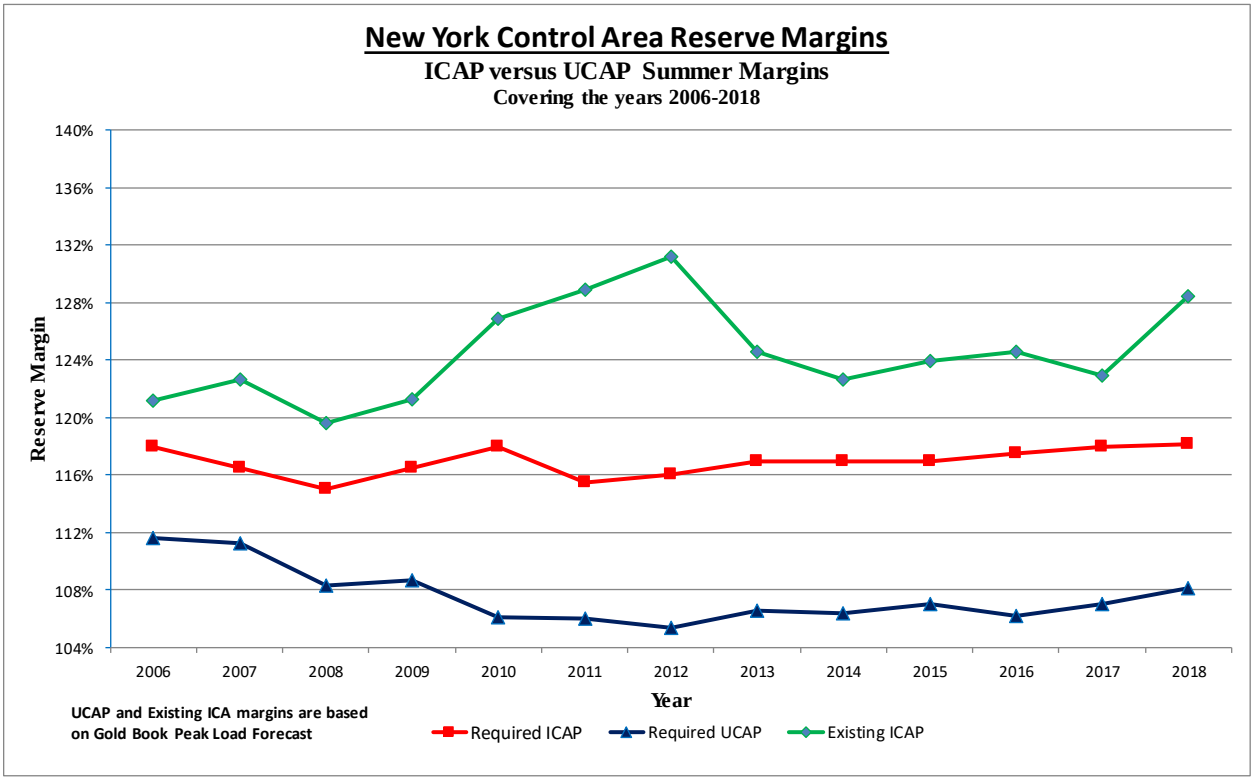
The NYISO values capacity sold and purchased in the market in a manner that considers the forced outage ratings (UCAP) of individual units. To maintain consistency between the DMNC rating of a unit translated to UCAP and the statewide ICR, the ICR must also be translated to an unforced capacity basis. 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



Appendices

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

Table of Contents

A. Reliability Calculation Models and Assumptions 3

A.1 GE MARS 5

A.2 Methodology 9

A.3 Base Case Modeling Assumptions 10

A.4 MARS Data Scrub 42

B. Details for Study Results 46

B.1 Sensitivity Results 46

B.2 Impacts of Environmental Regulations 47

B.3 Frequency of Implementing Emergency Operating Procedures 52

C. ICAP to UCAP Translation 54

C.1 NYCA and NYC and LI Locational Translations 55

C.2 Transmission Districts ICAP to UCAP Translation 60

C.3 Wind Resource Impact on the NYCA IRM and UCAP Markets 68

D. Glossary 70

Table of Tables & Figures

Figure A.1 NYCA ICAP Modeling 3
Table A.1 Modeling Details 4
Equation A.1 Transition Rate Definition 6
Equation A.2 Transition Rate Calculation Example 7
Table A.2 State Transition Rate Example 7
Table A.3 Load Model 10
Table A.4 2019 IRM NYCA Peak Load Forecast 11
Table A.5 2019 Load Forecast Uncertainty Models 12
Figure A.2 LFU Distributions 13
Figure A.3 Per Unit Load Shapes 14
Table A.6 Capacity Resources 15
Table A.7 Wind Generation 18
Figure A.4 NYCA Annual Zonal EFORds 21
Figure A.5 Five-Year Zonal EFORds 22
Figure A.6 NYCA Annual Availability by Fuel 23
Figure A.7 NYCA Five-Year Availability by Fuel 24
Figure A.8 NERC Annual Availability by Fuel 25
Figure A.9 NERC Five-Year Availability by Fuel 26
Figure A.10 Planned and Maintenance Outage Rates 28
Figure A.11 Scheduled Maintenance 28
Table A.8 Transmission System Model 30
Figure A.12 2018 IRM Topology 32
Figure A.13 Dynamic Interface Ratings Information 33
Table A.9 Interface Limits Updates 34
Table A.10 Distribution of Power Transfers between PJM and NY 35
Table A.11 Summary of major changes from 2018 to 2019 IRM topology: 35
Table A.12 External Area Representations 37
Table A.13 Outside World Reserve Margins 38
Table A.14 Assumptions for Emergency Operating Procedures 39
Table A.15 Emergency Operating Procedures Values 40
Table A.16 SCR Performance 41
Table A.17 GE MARS Data Scrub 42
Table A.18 NYISO MARS Data Scrub 43
Table A.19 Transmission Owner Data Scrub 44
Table B.1 Sensitivity Case Results 46
Table B.2 Implementation of EOP steps 52
Table C.1 Historical NYCA Capacity Parameters 54
Table C.2 NYCA ICAP to UCAP Translation 56
Table C.3 New York City ICAP to UCAP Translation 57

Table C.4 Long Island ICAP to UCAP Translation 58
Table C.5 GHIJ ICAP to UCAP Translation 59
Table C.6 Central Hudson Gas & Electric ICAP to UCAP Translation 60
Table C.7 Con Ed ICAP to UCAP Translation 61
Table C.8 LIPA ICAP to UCAP Translation 62
Table C.9 NGRID ICAP to UCAP Translation 63
Table C.10 NYPA ICAP to UCAP Translation 64
Table C.11 NYSEG ICAP to UCAP Translation 65
Table C.12 O & R ICAP to UCAP Translation 66
Table C.13 RGE ICAP to UCAP Translation 67

Appendices

Appendix A

NYCA Installed Capacity Requirement

Reliability Calculation Models and Assumptions

Description of the GE MARS Program: Load, Capacity, Transmission, Outside World Model, and Assumptions

A. Reliability Calculation Models and Assumptions

The reliability calculation process for determining the NYCA IRM requirement utilizes a probabilistic approach. This technique calculates the probabilities of outages of generating units, in conjunction with load and transmission models, to determine the number of days per year of expected capacity shortages. The General Electric Multi-Area Reliability Simulation (GE-MARS) is the primary computer program used for this probabilistic analysis. The result of the calculation for "Loss of Load Expectation" (LOLE) provides a consistent measure of system reliability. The various models used in the NYCA IRM calculation process are depicted in Figure A.1 below.

Table A.1 lists the study parameters, the source for the study assumptions, and where the assumptions are described in Appendix A. Finally, section A.3 compares the assumptions used in the 2018 and 2019 IRM reports.

Figure A.1 NYCA ICAP Modeling

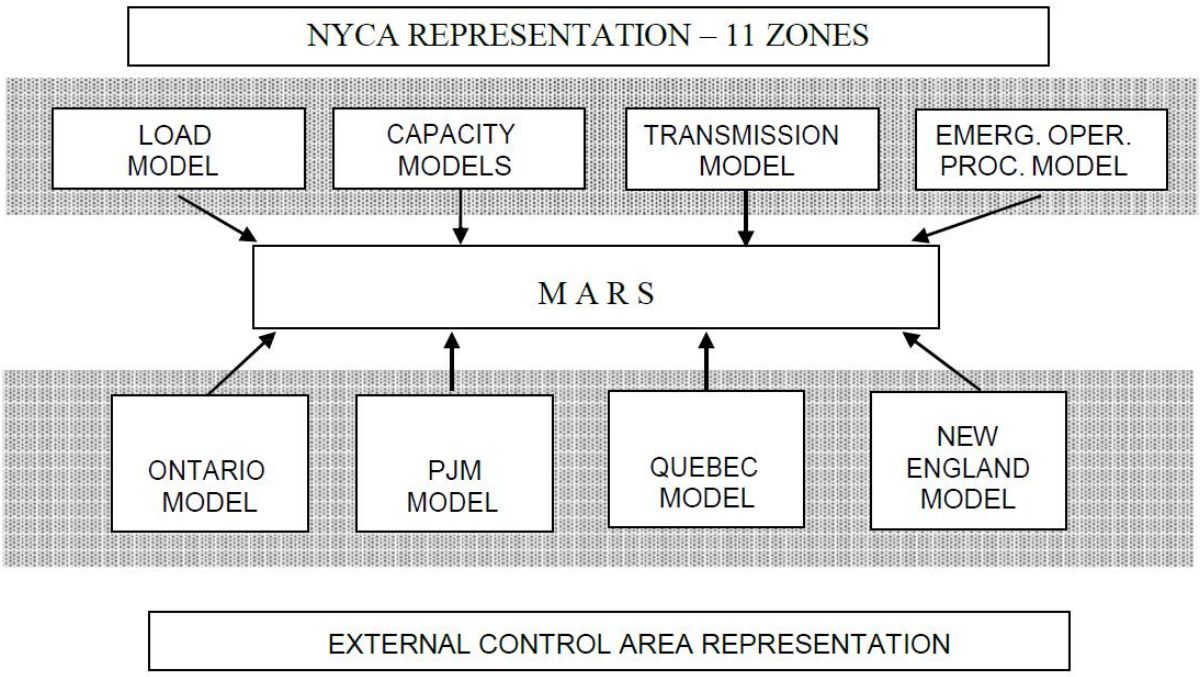


Table A.1 Modeling Details

#	Parameter	Description	Source	Reference
Internal NYCA Modeling				
1	GE MARS	General Electric Multi-Area Reliability Simulation Program		Section A.1
2	11 Zones	Load Areas	Fig A.1	NYISO Accounting & Billing Manual
3	Zone Capacity Models	Generator models for each generating in Zone Generator availability Unit ratings	GADS data 2018 Gold Book[1]	Section A.3.2
4	Emergency Operating Procedures	Reduces load during emergency conditions to maintain operating reserves	NYISO	Section A.3.5
5	Zone Load Models	Hourly loads	NYCA load shape and peak forecasts	Section A.3.1
6	Load Uncertainty Model	Account for forecast uncertainty due to weather conditions	Historical data	Section A.3.1
7	Transmission Capacity Model	Emergency transfer limits of transmission interfaces between Zones	NYISO Transmission Studies	Section A.3.3
External Control Area Modeling				
8	Ontario, Quebec, ISONE, PJM Control Area Parameters	See items 9-12 in this table	Supplied by External Control Area	
9	External Control Area Capacity models	Generator models in neighboring Control Areas	Supplied by External Control Area	Section A.3.4
10	External Control Area Load Models	Hourly loads	Supplied by External Control Area	Section A.3.4
11	External Control Area Load Uncertainty Models	Account for forecast uncertainty due to economic conditions	Supplied by External Control Area	Section A.3.4
12	Interconnection Capacity Models	Emergency transfer limits of transmission interfaces between control areas.	Supplied by External Control Area	Section A.3.3

[1] 2018 Load and Capacity Data Report, http://www.nyiso.com/public/markets_operations/services/planning/documents/index.jsp

A.1 GE MARS

As the primary probabilistic analysis tool used for establishing NYCA IRM requirements, the GE-MARS program includes a detailed load, generation, and transmission representation for 11 NYCA Zones, as well as the four external Control Areas (Outside World Areas) interconnected to the NYCA (see Section A.3 for a description of these Zones and Outside World Areas).

A sequential Monte Carlo simulation forms the basis for GE-MARS. The Monte Carlo method provides a fast, versatile, and easily expandable program that can be used to fully model many different types of generation, transmission, and demand-side options. GE-MARS calculates the standard reliability indices of daily and hourly LOLE (days/year and hours/year) and Loss of Energy Expectation (LOEE in MWh/year). The use of sequential Monte Carlo simulation allows for the calculation of time-correlated measures such as frequency (outages/year) and duration (hours/outage). The program also calculates the need for initiating Emergency Operating Procedures (EOPs), expressed in days/year (see Section A.3.5).

In addition to calculating the expected values for the reliability indices, GE-MARS also produces probability distributions that show the actual yearly variations in reliability that the NYCA could be expected to experience. In determining NYCA reliability, there are several types of randomly occurring events that must be taken into consideration. Among these are the forced outages of generating units and transmission capacity. Monte Carlo simulation models the effects of such random events. Deviations from the forecasted loads are captured using a load forecast uncertainty model.

Monte Carlo simulation approaches can be categorized as “non-sequential” and “sequential”. A non-sequential simulation process does not move through time chronologically or sequentially, but rather considers each hour independent of every other hour. Because of this, non-sequential simulation cannot accurately model issues that involve time correlations, such as maintenance outages, and cannot be used to calculate time-related indices such as frequency and duration.

Sequential Monte Carlo simulation (used by GE-MARS) steps through the year chronologically, recognizing the status of equipment is not independent of its status in adjacent hours. Equipment forced outages are modeled by taking the equipment

out of service for contiguous hours, with the length of the outage period being determined from the equipment's mean time to repair. Sequential simulation can model issues of concern that involve time correlations and can be used to calculate indices such as frequency and duration. It also models transfer limitations between individual areas.

Because the GE-MARS Program is based on a sequential Monte Carlo simulation, it uses state transition rates, rather than state probabilities, to describe the random forced outages of the thermal units. State probabilities give the probability of a unit being in a given capacity state at any particular time and can be used if one assumes that the unit's capacity state for a given hour is independent of its state at any other hour. Sequential Monte Carlo simulation recognizes the fact that a unit's capacity state in any given hour is dependent on a given state in previous hours and influences its state in future hours. It thus requires additional information that is contained in the transition rate data.

For each unit, a transition rate matrix is input that shows the transition rates to go from each capacity state to each other capacity state. The transition rate from state A to state B is defined as the number of transitions from A to B per unit of time in state A (Equation A.1).

Equation A.1 Transition Rate Definition

$$Transition\ (A\ to\ B) = \frac{Number\ of\ Transitions\ from\ A\ to\ B}{Total\ Time\ in\ State\ A}$$

Table A.2 shows the calculation of the state transition rates from historic data for one year. The Time-in-State Data shows the amount of time that the unit spent in each of the available capacity states during the year; the unit was on planned outage for the remaining 760 hours. The Transition Data shows the number of times that the unit transitioned from each state to each other state during the year. The State Transition Rates can be calculated from this data. For example, the transition rate from state 1 to state 2 equals the number of transitions from 1 to 2 divided by the total time spent in state 1 (Equation A.2).

Equation A.2 Transition Rate Calculation Example

$$Transition\ (1\ to\ 2) = \frac{(10\ Transitions)}{5{,}000\ Hours} = 0.0002$$

Table A.2 State Transition Rate Example

Time in State Data				Transition Data			
State	MW	Hours		From State	To State 1	To State 2	To State 3
1	200	5000		1	0	10	5
2	100	2000		2	6	0	12
3	0	1000		3	9	8	0

State Transition Rates			
From State	To State 1	To State 2	To State 3
1	0.000	0.002	0.001
2	0.003	0.000	0.006
3	0.009	0.008	0.000

From the state transition rates for a unit, the program calculates the two important quantities that are needed to model the random forced outages on the unit: the average time that the unit resides in each capacity state, and the probability of the unit transitioning from each state to each other state.

Whenever a unit changes capacity states, two random numbers are generated. The first is used to calculate the amount of time that the unit will spend in the current state; it is assumed that the time in a state is exponentially distributed, with a mean as computed from the transition rates. This time in state is added to the current simulation time to calculate when the next random state change will occur. The second random number is combined with the state transition probabilities to determine the state to which the unit will transition when it leaves its current state. The program thus knows for every unit on the system, its current state, when it will be leaving that state, and the state to which it will go next.

Each time a unit changes state, because of random state changes, the beginning or ending of planned outages, or mid-year installations or retirements, the total

capacity available in the unit's area is updated to reflect the change in the unit's available capacity. This total capacity is then used in computing the area margins each hour.

A.1.1 Error Analysis

An important issue in using Monte Carlo simulation programs such as GE-MARS is the number of years of artificial history (or replications) that must be created to achieve an acceptable level of statistical convergence in the expected value of the reliability index of interest. The degree of statistical convergence is measured by the standard deviation of the estimate of the reliability index that is calculated from the simulation data.

The standard deviation has the same physical units (*e.g.,* days/year) as the index being estimated, and thus its magnitude is a function of the type of index being estimated. Because the standard deviation can assume a wide range of values, the degree of convergence is often measured by the standard error, which is the standard deviation of the estimated mean expressed as a per unit of the mean.

Convergence can also be expressed in terms of a confidence interval that defines the range in which you can state, with a given level of confidence that the actual value falls within the interval. For example, a range centered on the mean of two standard deviations in each direction (plus and minus) defines a confidence interval of 95%.

For this analysis, the Base Case required 407 replications to converge to a standard error of 0.05 and required 1,943 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 days/year for NYCA was met with a standard error less than 0.025. The confidence interval at this point ranges from 16.6% to 17.0%. It should be recognized that an 16.8% IRM is in full compliance with the NYSRC Resource Adequacy rules and criteria (see Base Case Study Results section).

A.1.2 Conduct of the GE-MARS analysis

The study was performed using Version 3.22.6 of the GE-MARS software program. This version has been benchmark tested by the NYISO.

The current base case is the culmination of the individual changes made to last year's base case. Each change, however, is evaluated individually against last year's base case. The LOLE results of each of these pre-base case simulations are reviewed to confirm that the reliability impact of the change is reasonable and explainable.

General Electric was asked to review the input data for errors. They have developed a program called "Data Scrub" which processes the input files and flags data that appears to be out of the ordinary. For example, it can identify a unit with a forced outage rate significantly higher than all the others in that size and type category. If something is found, the ISO reviews the data and either confirms that it is correct as is or institutes a correction. The results of this data scrub are shown in Section A.4.

The top three summer peak loads of all Areas external to NYCA are aligned to be on the same days as that of NYCA, even though they may have historically occurred at different times. This is a conservative approach, using the assumption that peak conditions could be the result of a wide spread heat wave. This would result in reducing the amount of assistance that NYCA could receive from the other Areas.

A.2 Methodology

The 2019 IRM study continues to use the Unified Methodology that simultaneously provides a basis for the NYCA installed reserve requirements and the preliminary locational installed capacity requirements. The IRM/preliminary LCR characteristic consists of a curve function, "a knee of the curve" and straight-line segments at the asymptotes. The curve function is represented by a quadratic (second order) curve which is the basis for the Tan 45 inflection point calculation. Inclusion of IRM/preliminary LCR point pairs remote to the "knee of the curve" may impact the calculation of the quadratic curve function used for the Tan 45 calculation.

The procedure for determining the best fit curve function used for the calculation of the Tan 45 inflection point to define the base case requirement is based on the following methodology:

1) Start with all points on IRM/preliminary LCR Characteristic.
2) Develop regression curve equations for all different point to point segments consisting of at least four consecutive points.
3) Rank all the regression curve equations based on the following:
   - Sort regression equations with highest R2.

- Remove any equations which show a negative coefficient in the first term. This is the constant labeled 'a' in the quadratic equation: ax2+bx+c
- Ensure calculated IRM is within the selected point pair range, i.e., if the curve fit was developed between 14% and 18% and the calculated IRM is 13.9%, the calculation is invalid.
- In addition, there must be at least one statewide reserve margin point to the left and right of the calculated tan 45 point.
- Ensure the calculated IRM and corresponding preliminary LCR do not violate the 0.1 LOLE criteria.
- Check results to ensure they are consistent with visual inspection methodology used in past years' studies.

This approach identifies the quadratic curve functions with highest R^2 correlations as the basis for the Tan 45 calculation. The final IRM is obtained by averaging the Tan 45 IRM points of the NYC and LI curves. The Tan 45 points are determined by solving for the first derivatives of each of the "best fit" quadratic functions as a slope of -1. Lastly, the resulting preliminary LCR values are identified.

A.3 Base Case Modeling Assumptions

A.3.1 Load Model

Table A.3 Load Model

Parameter	2018 Study Assumption	2019 Study Assumption	Explanation
Peak Load	October 1, 2017 NYCA: 32,868 MW NYC: 11,541 MW LI: 5,445 MW G-J: 15,890 MW	October 1, 2018 NYCA: 32,488 MW NYC: 11,585 MW LI: 5,346 MW G-J: 15,831 MW	Forecast based on examination of 2018 weather normalized peaks. Top three external Area peak days aligned with NYCA
Load Shape Model	Multiple Load Shapes Model using years **2002 (Bin 2), 2006 (Bin 1), and 2007 (Bin 3-7)**	Multiple Load Shapes Model using years **2002 (Bin 2), 2006 (Bin 1), and 2007 (Bin 3-7)**	No Change
Load Uncertainty Model	Statewide and zonal model updated to reflect current data	Statewide and zonal model updated to reflect current data	No Change from 2108 IRM. Based on TO and NYISO data and analyses.

(1) Peak Load Forecast Methodology

The procedure for preparing the IRM forecast is very similar to that detailed in the NYISO Load Forecasting Manual for the ICAP forecast. The NYISO's Load Forecasting Task Force had two meetings in September 2018 to review weather-adjusted peaks for the summer of 2018 prepared by the NYISO and the Transmission Owners. Regional load growth factors (RLGFs) for 2019 were updated by most Transmission Owners; otherwise the same RLGFs that were used for the 2018 ICAP forecast were maintained. The 2019 forecast was produced by applying the RLGFs to each TO's weather-normalized peak for the summer of 2018.

The results of the analysis are shown in Table A-4. The 2018 IRM peak forecast was 32,868 MW. The actual peak of 31,936 MW (col. 2) occurred on August 29, 2018. After accounting for the impacts of weather and other factors, the weather-adjusted peak load was determined to be 32,444 MW (col. 6), 424 MW (1.3%) below the IRM forecast. The Regional Load Growth Factors are shown in column 9. The 2019 forecast for the NYCA is 32,488 MW (col. 12). The Locality forecasts are also reported in the second table below.

The LFTF recommended this forecast to the NYSRC for its use in the 2019 IRM study.

Table A.4 2019 IRM NYCA Peak Load Forecast

2019 IRM Coincident Peak Forecast by Transmission District for NYSRC

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10a)=(8)*(9)	(10b)	(10c)=(10a)+(10b)
Transmission District	2018 Actual MW	Demand Response Estimate MW	2018 Estimated Muni Self-Gen	Weather Adjustment MW	2018 Weather Normalized MW	Loss Reallocation MW	2018 WN MW, Adj for Losses	Regional Load Growth Factors	2019 Forecast, Before Adjustments	BTM:NG and Other Adjustments to Load	2019 IRM Final Forecast
Con Edison	12,686	295	0	119	13,100	0	13,100	1.0038	13,150		13,150.0
Cen Hudson	1,102	7	0	-5	1,104	0	1,104	0.9920	1,095		1,095.0
LIPA	5,422	15	10	-115	5,332	0	5,332	0.9859	5,257	40.6	5,297.6
NGrid	6,680	214	56	-135	6,815	0	6,815	1.0010	6,822		6,822.0
NYPA	366	0	0	-2	364	0	364	1.1621	423		423.0
NYSEG	3,114	35	0	-34	3,115	0	3,115	0.9982	3,109	11.6	3,120.6
O&R	1,035	19	0	68	1,122	0	1,122	0.9822	1,102		1,102.0
RG&E	1,531	9	0	-48	1,492	0	1,492	0.9904	1,478		1,478.0
Total	31,936	594	66	-152	32,444	0	32,444	0.9998	32,436	52.2	32,488.2
						2019 Forecast from 2018 Gold Book			32,857		
						Change from 2018 Gold Book			-421		

2019 IRM Locality Peak Forecast by Transmission District for NYSRC

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11a)	(11b)=(8)+(11a)
Locality	2018 Actual MW	SCR/EDRP Estimate MW	2018 Estimated Muni Self-Gen	Locality Adjustment MW	2018 Weather Normalized MW	Regional Load Growth Factors	2019 Forecast, Before Adjustments	2019 Forecast from 2018 Gold Book	Change from Gold Book Forecast	BTM:NG and Other Adjustments to Load	2019 IRM Final Forecast
Zone J - NYC	11,018	100	0	422	11,540	1.0038	11,585	11,474	111		11,585.0
Zone K - LI	5,422	15	10	-67	5,380	0.9859	5,305	5,323	-18	40.6	5,345.6
Zone GHIJ	15,062	100	0	648	15,810	1.0013	15,831	15,815	16		15,831.0

(2) Zonal Load Forecast Uncertainty

The 2019 load forecast uncertainty (LFU) models are the same models that were used last year. Due to below-average peak-producing weather in Summer 2017, the models were not updated. The LFU model for Zone K was provided by LIPA. The NYISO developed models for Zones A through J and reviewed the Zone K model. The results of these models are presented in Table A-5. Each row represents the probability that a given range of load levels will occur, on a per-unit basis, by zone. These results are presented graphically in Figure A-2.

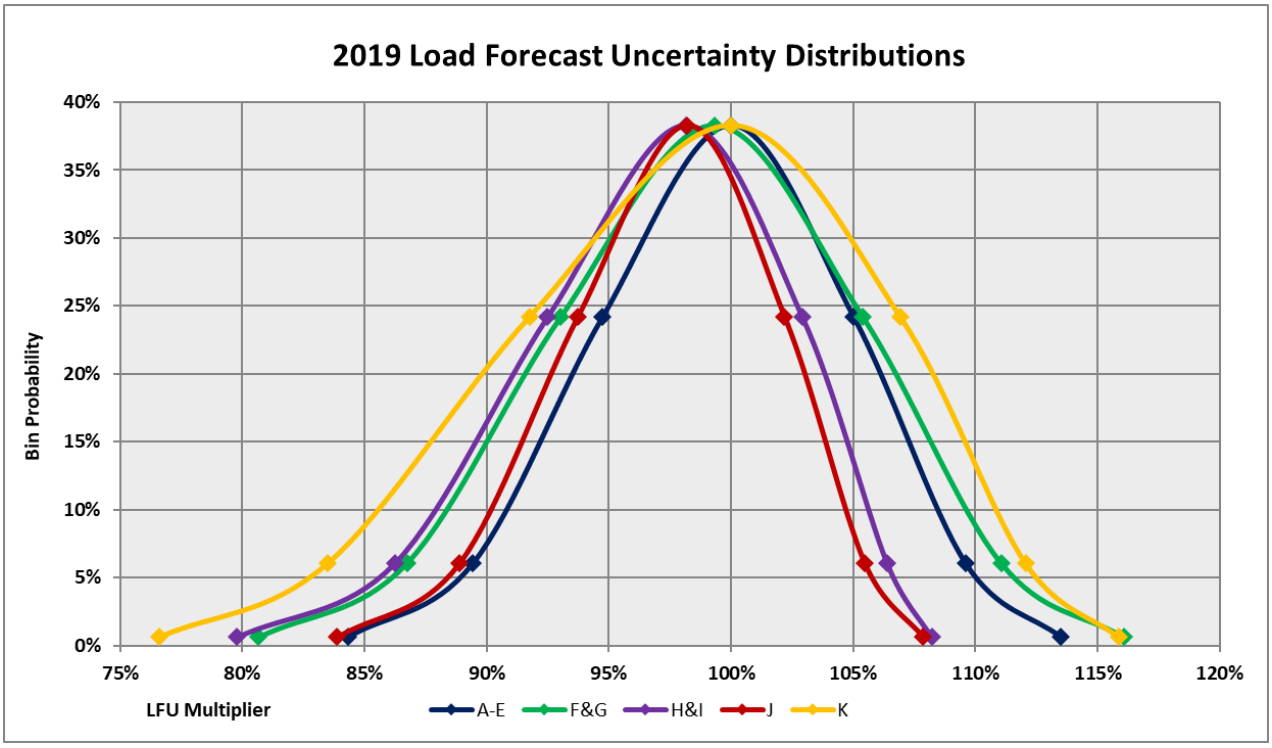
Table A.5 2019 Load Forecast Uncertainty Models

2019 Load Forecast Uncertainty Models

Bin	Probability	A-E	F&G	H&I	J	K
B7	0.62%	84.31%	80.67%	79.78%	83.88%	76.59%
B6	6.06%	89.44%	86.74%	86.24%	88.87%	83.51%
B5	24.17%	94.74%	93.03%	92.49%	93.71%	91.75%
B4	38.30%	100.00%	99.33%	98.17%	98.21%	100.00%
B3	24.17%	105.02%	105.41%	102.93%	102.19%	106.95%
B2	6.06%	109.59%	111.07%	106.39%	105.47%	112.06%
B1	0.62%	113.51%	116.08%	108.22%	107.86%	115.86%

Delta	A-E	F&G	H&I	J	K
Bin 4 - Bin 7	15.69%	18.66%	18.39%	14.34%	23.41%
Bin 1 - Bin 4	13.51%	16.76%	10.04%	9.65%	15.86%
Total Range	29.19%	35.42%	28.43%	23.99%	39.27%

Figure A.2 LFU Distributions



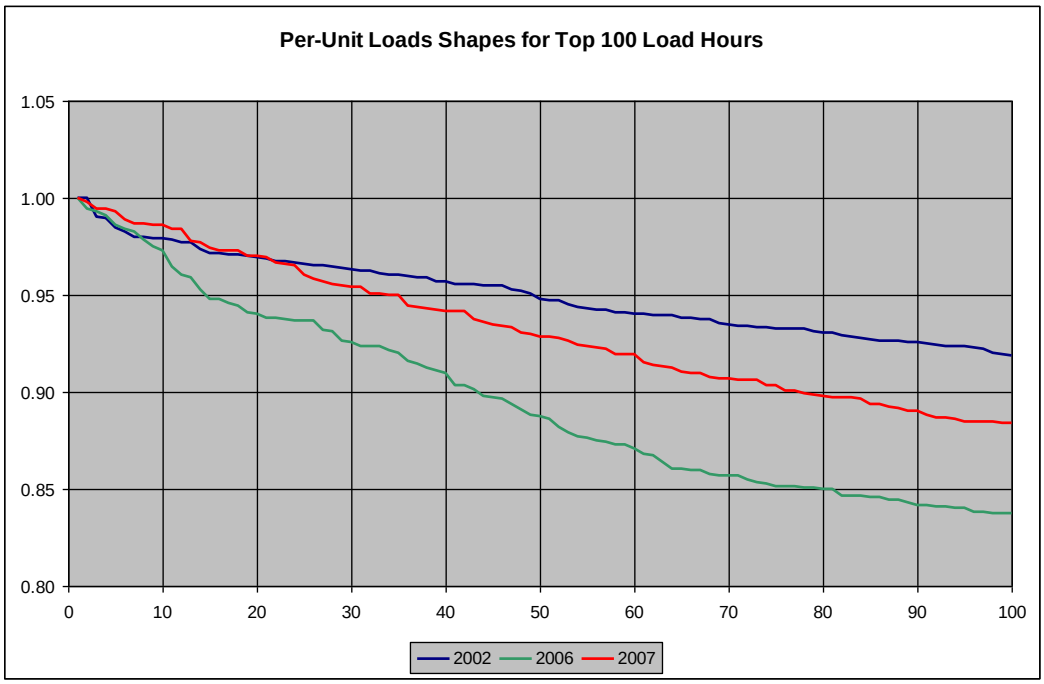
The Consolidated Edison models for Zones H, I & J are based on a peak demand with a 1-in-3 probability of occurrence (67th percentile). All other zones are designed at a 1-in-2 probability of occurrence of the peak demand (50th percentile). The methodology and results for determining the 2019 LFU models have been reviewed by the NYISO Load Forecasting Task Force.

(3) Zonal Load Shape Models for Load Bins

Beginning with the 2014 IRM Study, multiple load shapes were used in the load forecast uncertainty bins. Three historic years were selected from those available, as discussed in the NYISO's 2013 report, 'Modeling Multiple Load Shapes in Resource Adequacy Studies'. The year 2007 was assigned to the first five bins (from cumulative probability 0% to 93.32%). The year 2002 was assigned to the next highest bin, with a probability of 6.06%. The year 2006 was assigned to the highest bin, with a probability of 0.62%. The three load shapes for the NYCA are shown on a per-unit basis for the highest one hundred hours in Figure A.3. The year 2007 represents the load duration pattern of a typical year. The year 2002 represents the load duration pattern of many hours at high load levels. The year 2006

represents the load duration pattern of a heat wave, with a small number of hours at high load levels followed by a sharper decrease in per-unit values than the other two profiles.

Figure A.3 Per Unit Load Shapes



A.3.2 Capacity Model

The capacity model includes all NYCA generating units, including new and planned units, as well as units that are physically outside New York State that have met specific criteria to offer capacity in the New York Control Area. The 2018 Load and Capacity Data Report is the primary data source for these resources. Table A.6 provides a summary of the capacity resource assumptions in the 2019 IRM study.

Table A.6 Capacity Resources

Parameter	2018 Study Assumption	2019 Study Assumption	Explanation
Generating Unit Capacities	2017 Gold Book values. Use min (DMNC vs. CRIS) capacity value	2018 Gold Book values. Use min (DMNC vs. CRIS) capacity value	2018 Gold Book publication
Planned Generator Units	784 MW of new non- wind resources, plus 52 MW of project related re-ratings.	11.1 MW of new non- wind resources, plus 209.3 MW of project related re-ratings.	New resources + Unit rerates
Wind Resources	77.7 MW of Wind Capacity additions totaling 1733.4 MW of qualifying wind	158.3 MW of Wind Capacity additions totaling 1891.7 MW of qualifying wind	Renewable units based on RPS agreements, interconnection queue, and ICS input.
Wind Shape	Actual hourly plant output over the period 2012-2016. New units will use zonal hourly averages or nearby units.	Actual hourly plant output over the period 2013-2017. New units will use zonal hourly averages or nearby units.	Program randomly selects a wind shape of hourly production over the years 2013-2017 for each model iteration.
Solar Resources (Grid connected)	31.5 MW Solar Capacity. Model chooses from 4 years of production data covering the period 2013-2016.	Total of 31.5 MW of qualifying Solar Capacity. (Attachment B3)	ICAP Resources connected to Bulk Electric System
Solar Shape	Actual hourly plant output over the period 2012-2016. New units will use zonal hourly averages or nearby units.	Actual hourly plant output over the period 2013-2017. New units will use zonal hourly averages or nearby units.	Program randomly selects a solar shape of hourly production over the years 2013-2017 for each model iteration.

Parameter	2018 Study Assumption	2019 Study Assumption	Explanation
BTM- NG Program	Model these units at their full CRIS adjusted output value Added 47.0 MW generator Added Load (40.6 MW during 2018 load forecast) Removed Stony Brook (9.6 MW CRIS) from the generator list value	Addition of Greenidge 4 to BTM NG program. 104.3 MW unit. Forecast load adjustment of 11.6 MW	Both the load and generation of the BTM:NG Resources are modeled.
Retirements, Mothballed units, and ICAP ineligible units	0 MW of retirements or mothballs reported or Units in IIFO and IR	0 MW of retirements, 399.2 MW of unit deactivations, and 389.4 MW of IIFO and 0 MW IR[2]	2018 Gold Book publication and generator notifications
Forced and Partial Outage Rates	Five-year (2012-2016) GADS data for each unit represented. Those units with less than five years – use representative data.	Five-year (2013-2017) GADS data for each unit represented. Those units with less than five years – use representative data.	Transition Rates representing the Equivalent Forced Outage Rates (EFORd) during demand periods over the most recent five-year period (2013-2017)
Planned Outages	Based on schedules received by the NYISO	Based on schedules received by the NYISO	Updated schedules
Summer Maintenance	Nominal 50 MWs – divided equally between upstate and downstate	Nominal 50 MWs – divided equally between Zones J & K	Review of most recent data

[2] ICAP Ineligible Forced Outage (IIFO) and inactive Reserve (IR)

Parameter	2018 Study Assumption	2019 Study Assumption	Explanation
Gas Turbine Ambient De-rate	De-rate based on provided temperature correction curves.	De-rate based on provided temperature correction curves.	Operational history indicates de-rates in line with manufacturer's curves
Small Hydro Resources	Actual hourly plant output over the period 2012-2016.	Actual hourly plant output over the period 2013-2017.	Program randomly selects a Hydro shape of hourly production over the years 2013-2017 for each model iteration.
Large Hydro	Probabilistic Model based on 5 years of GADS data	Probabilistic Model based on 5 years of GADS data	Transition Rates representing the Equivalent Forced Outage Rates (EFORd) during demand periods over the most recent five-year period (2013-2017)

(1) Generating Unit Capacities

The capacity rating for each thermal generating unit is based on its Dependable Maximum Net Capability (DMNC). The source of DMNC ratings are seasonal tests required by procedures in the NYISO Installed Capacity Manual. Additionally, each generating resource has an associated capacity CRIS (Capacity Resource Interconnection Service) value. When the associated CRIS value is less than the DMNC rating, the CRIS value is modeled.

Wind units are rated at the lower of their CRIS value or their nameplate value in the model. The 2018 NYCA Load and Capacity Report, issued by the NYISO, is the source of those generating units and their ratings included on the capacity model.

(2) Planned Generator Units

One planned new non-wind generating unit, Arthur Kill Cogen, having a total capacity of 11.1 MW, is included in the 2019 IRM Study. In addition, increased

ratings on Bethlehem Energy Center, Bayonne Energy Center II, East River 1, 2, and 6, and Nine Mile Point 2 totaled 209.3 MW.

(3) Wind Modeling

Wind generators are modeled as hourly load modifiers using hourly production data over the period 2013-2017. Each calendar production year represents an hourly wind shape for each wind facility from which the GE MARS program will randomly select. New units will use the zonal hourly averages of current units within the same zone. Characteristics of this data indicate a capacity factor of approximately 16.3 % during the summer peak hours. As shown in table A.7, a total of 1,891.7 MW of installed capacity associated with wind generators is included in this study including 158.3 MW of planned new wind capacity.

Table A.7 Wind Generation

Wind Generation				
Wind Resouce	**Zone**	**CRIS (MW)**	**Summer Capability (MW)**	**CRIS adusted value from 2018 Gold Book (MW)**
ICAP Participating Wind Units				
Altona Wind Power	D	97.5	97.5	97.5
Bliss Wind Power	A	100.5	100.5	100.5
Canandaigua Wind Power	C	125.0	125.0	125.0
Chateaugay Wind Power	D	106.5	106.5	106.5
Clinton Wind Power	D	100.5	100.5	100.5
Ellenburg Wind Power	D	81.0	81.0	81.0
Hardscrabble Wind	E	74.0	74.0	74.0
High Sheldon Wind Farm	C	112.5	118.1	112.5
Howard Wind	C	57.4	55.4	55.4
Madison Wind Power	E	11.5	11.6	11.5
Maple Ridge Wind 1	E	231.0	231.0	231.0
Maple Ridge Wind 2	E	90.7	90.8	90.7
Munnsville Wind Power	E	34.5	34.5	34.5
Orangeville Wind Farm	C	94.4	93.9	93.9
Wethersfield Wind Power	C	126.0	126.0	126.0
Marble River	D	215.2	215.5	215.2
Jericho Rise	D	77.7	77.7	77.7
		1735.9	**1739.5**	**1733.4**
New and Proposed IRM Study Wind Units				
Copenhagen Wind	E	79.9	79.9	79.9
Arkwright Summit	A	78.4	78.4	78.4
		158.3	**158.3**	**158.3**
Non - ICAP Participating Wind Units				
	Zone	**CRIS (MW)**	**Nameplate Capability (MW)**	**CRIS adusted value from 2018 Gold Book (MW)**
Erie Wind	A	0.0	15.0	0.0
Fenner Wind Farm	C	0.0	30.0	0.0
Steel Wind	A	0.0	20.0	0.0
Western NY Wind Power	C	0.0	6.6	0.0
		0.0	**71.6**	0.0
Total Wind Resources		1894.2	1969.4	**1891.7**

(4) Solar Modeling

Solar generators are modeled as hourly load modifiers using hourly production data over the period 2013-2017. Each calendar production year represents an hourly solar shape for each solar facility which the GE MARS program will randomly select from. A total of 31.5 MW of solar capacity was modeled in Zone K.

(5) Retirements/Deactivations/ ICAP Ineligible

There are no units slated to retire before the summer of 2019. Three units totaling 399.2 MW have become deactivated. In addition, ten plants totaling 389.4 MW, have been placed in ICAP ineligible status and are removed from this study.

(6) Forced Outages

Performance data for thermal generating units in the model includes forced and partial outages, which are modeled by inputting a multi-state outage model that is representative of the "equivalent demand forced outage rate" (EFORd) for each unit represented. Generation owners provide outage data to the NYISO using Generating Availability Data System (GADS) data in accordance with the NYISO Installed Capacity Manual. The NYSRC is continuing to use a five-year historical period for the 2019 IRM Study.

Figure A.4 shows the trend of EFORd for various regions within NYCA.

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

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

The multi-state model for each unit is derived from five years of historic events if it is available. For units with less than five years of historic events, the available years of event data for the unit is used if it appears to be reasonable. For the remaining years, the unit NERC class-average data is used.

The unit forced outage states for the most of the NYCA units were obtained from the five-year NERC GADS outage data collected by the NYISO for the years 2013 through 2017. This hourly data represents the availability of the units for all hours. From this, full and partial outage states and the frequency of occurrence were calculated and put in the required format for input to the GE-MARS program.

Figures A.8 and A.9 show the unit availabilities of the entire NERC fleet on an annual and 5-year historical basis.

Figure A.4 NYCA Annual Zonal EFORds

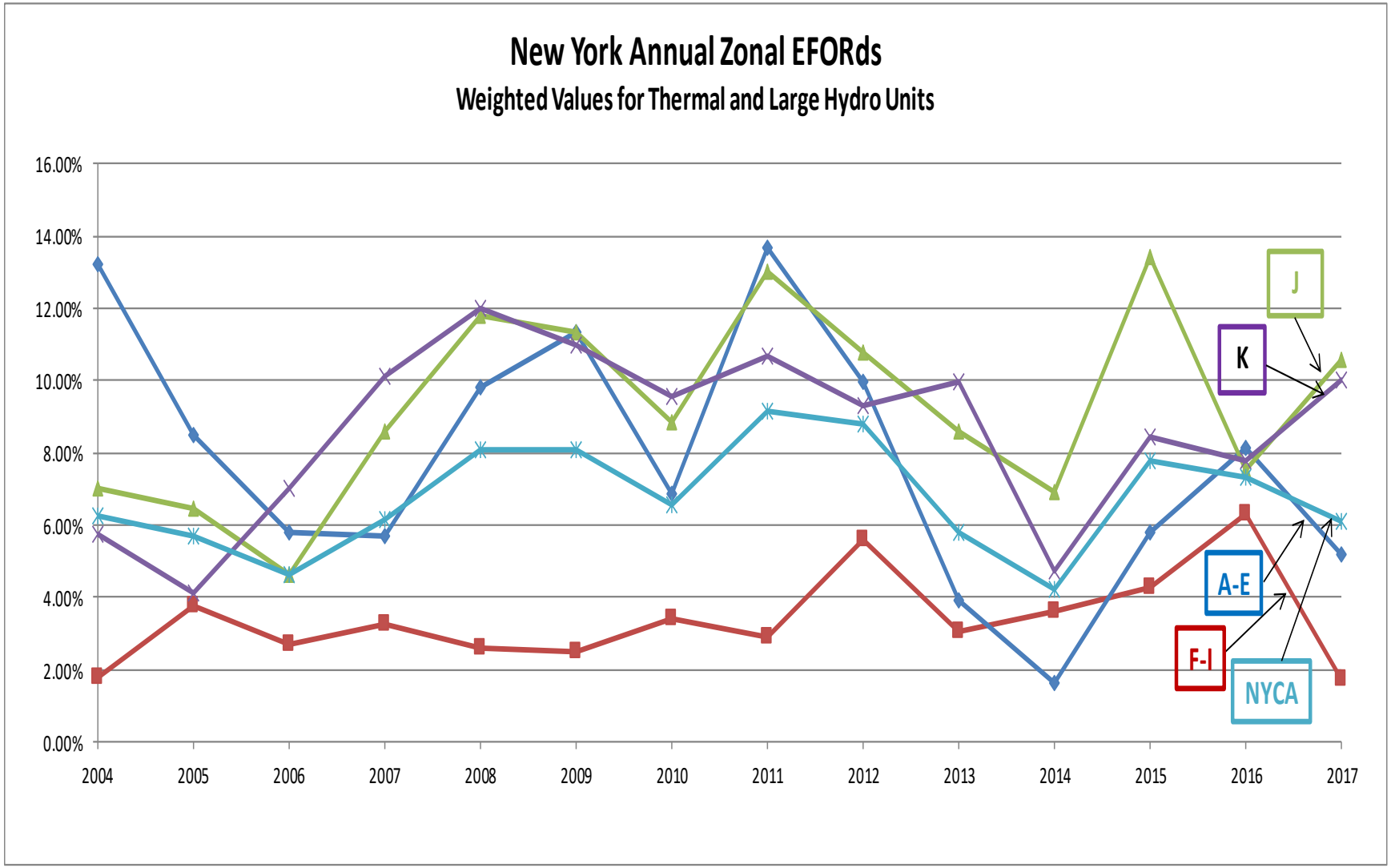
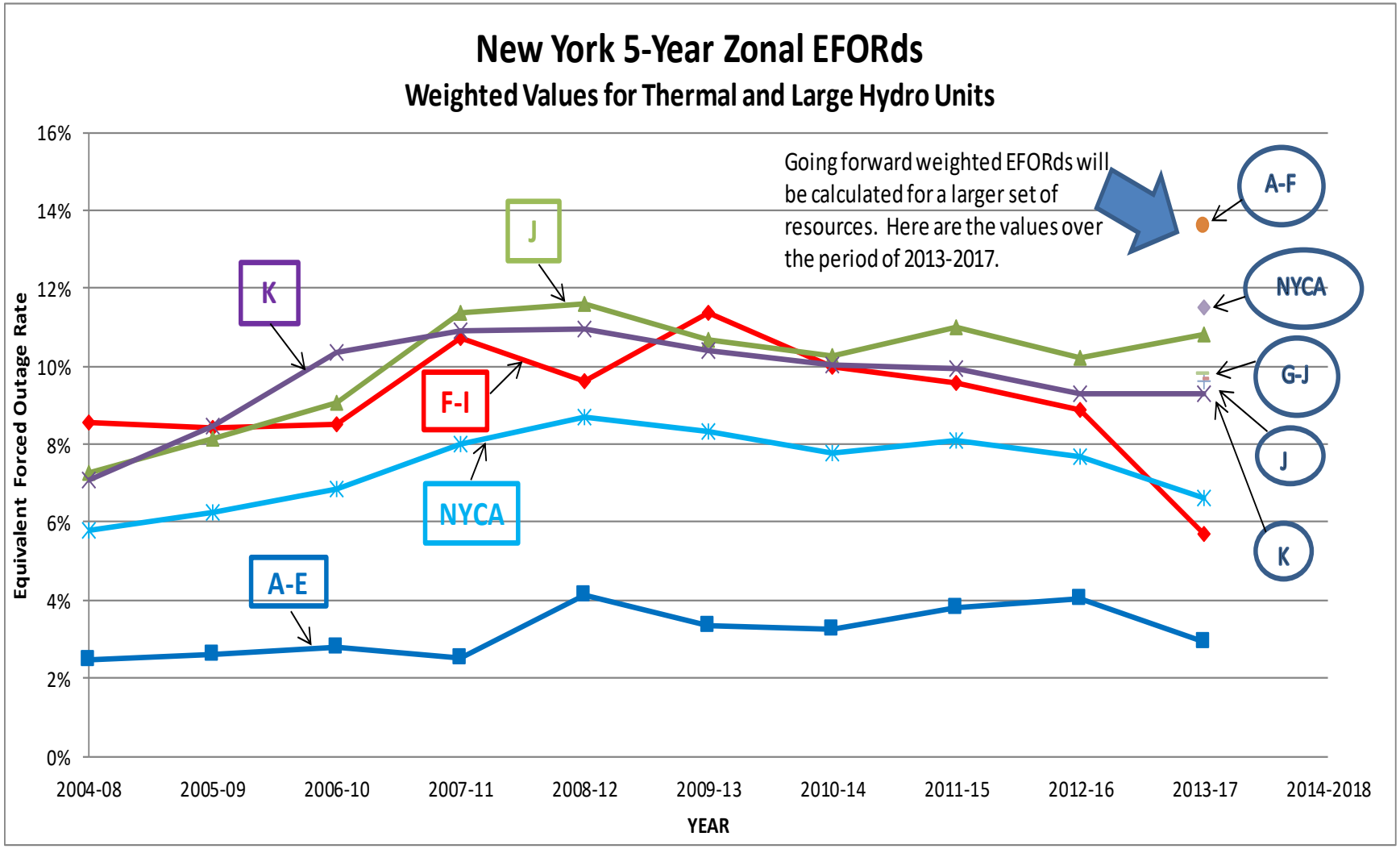


Figure A.5 Five-Year Zonal EFORds



The larger set includes thermal, large hydro, wind, solar, landfill gas, and run-of-river resources with CRIS.

Figure A.6 NYCA Annual Availability by Fuel

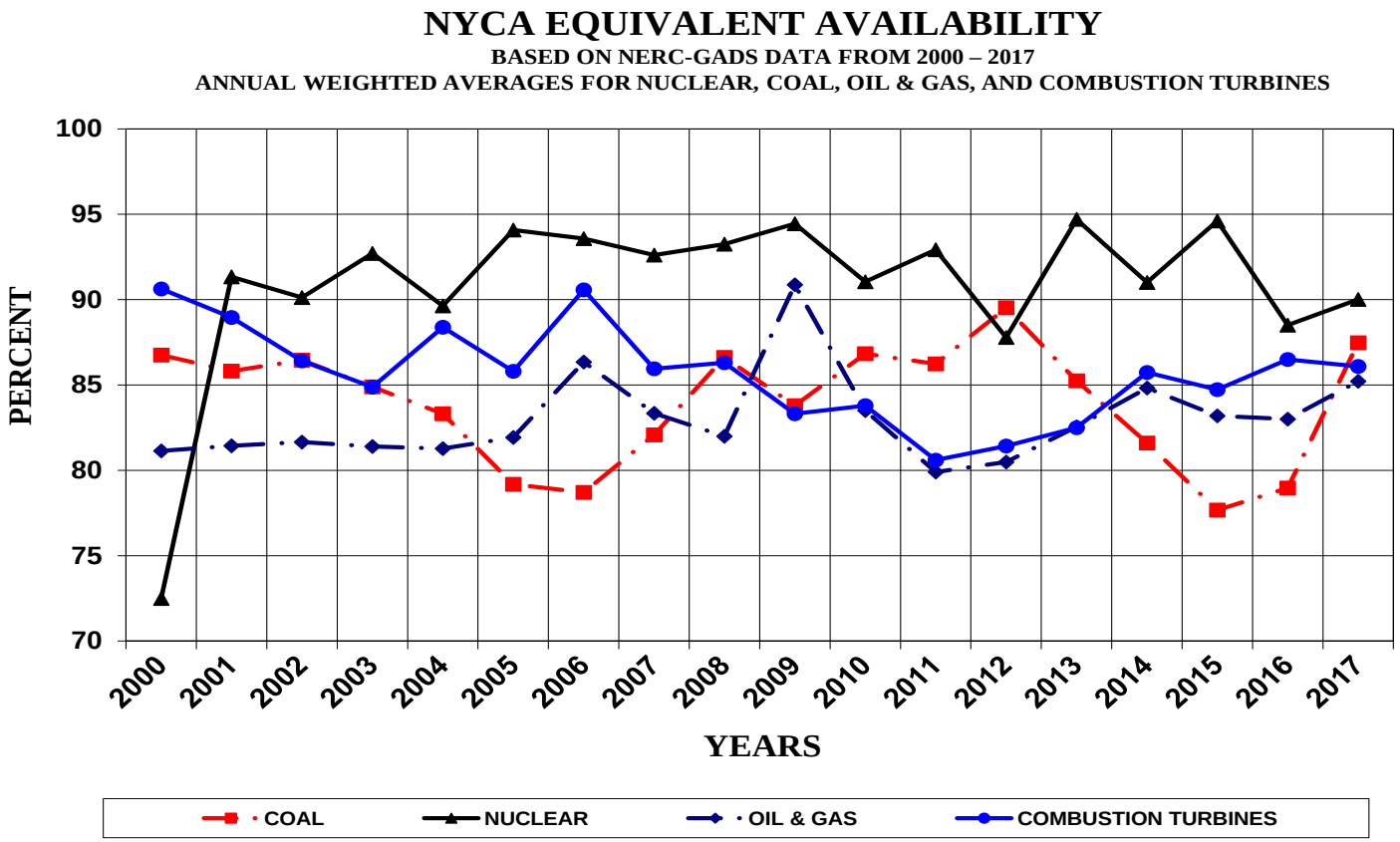


Figure A.7 NYCA Five-Year Availability by Fuel

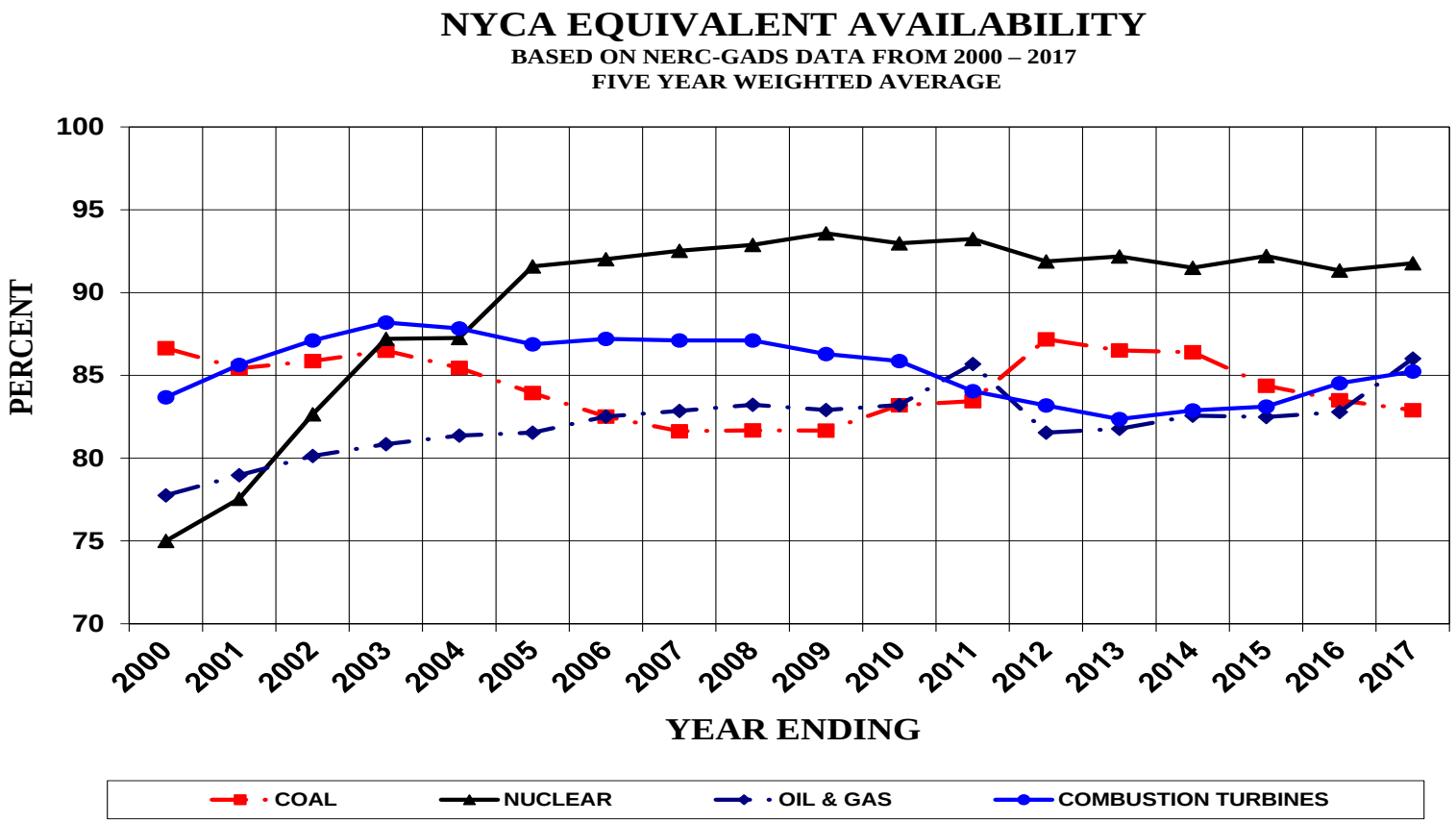


Figure A.8 NERC Annual Availability by Fuel

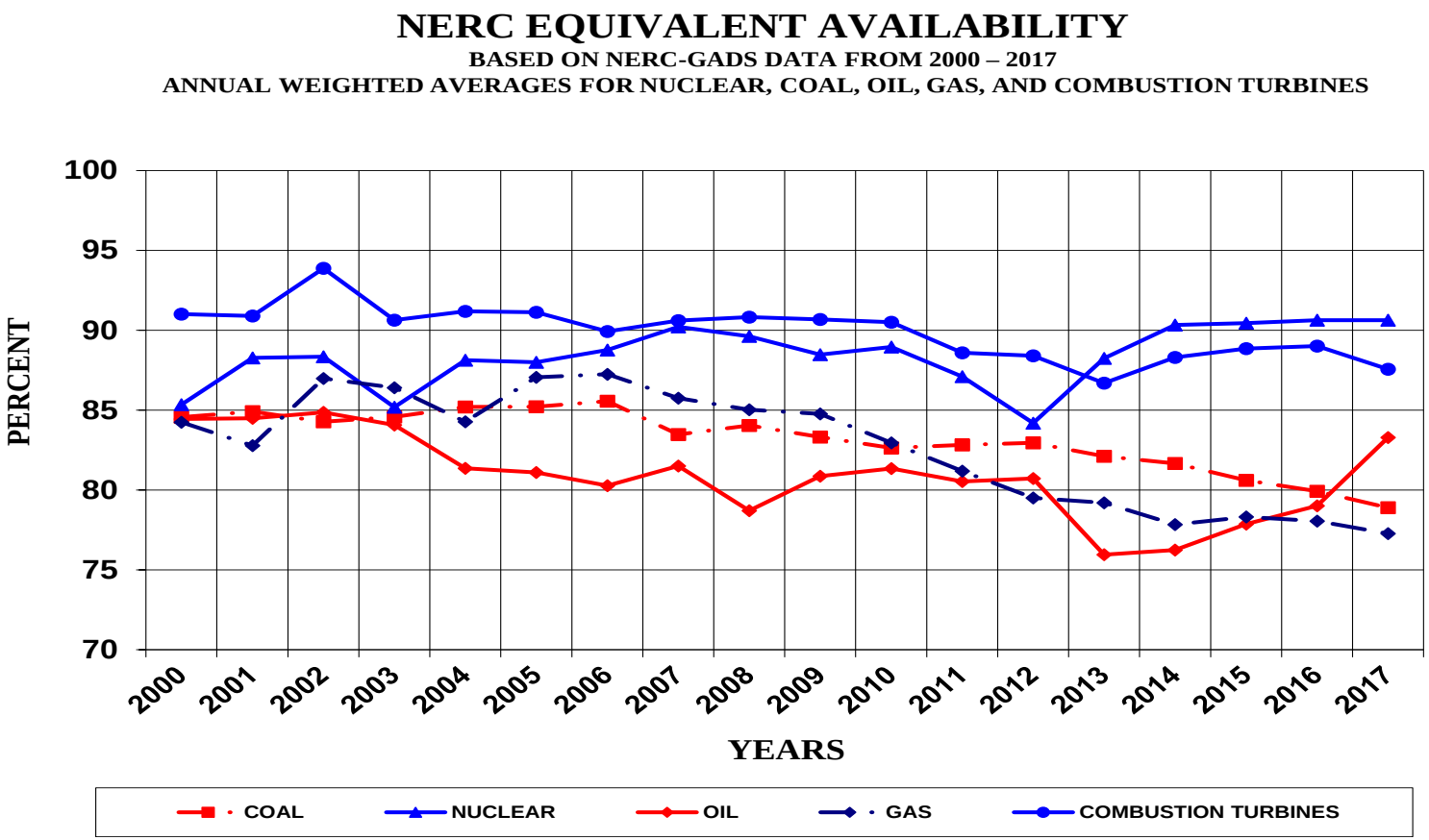
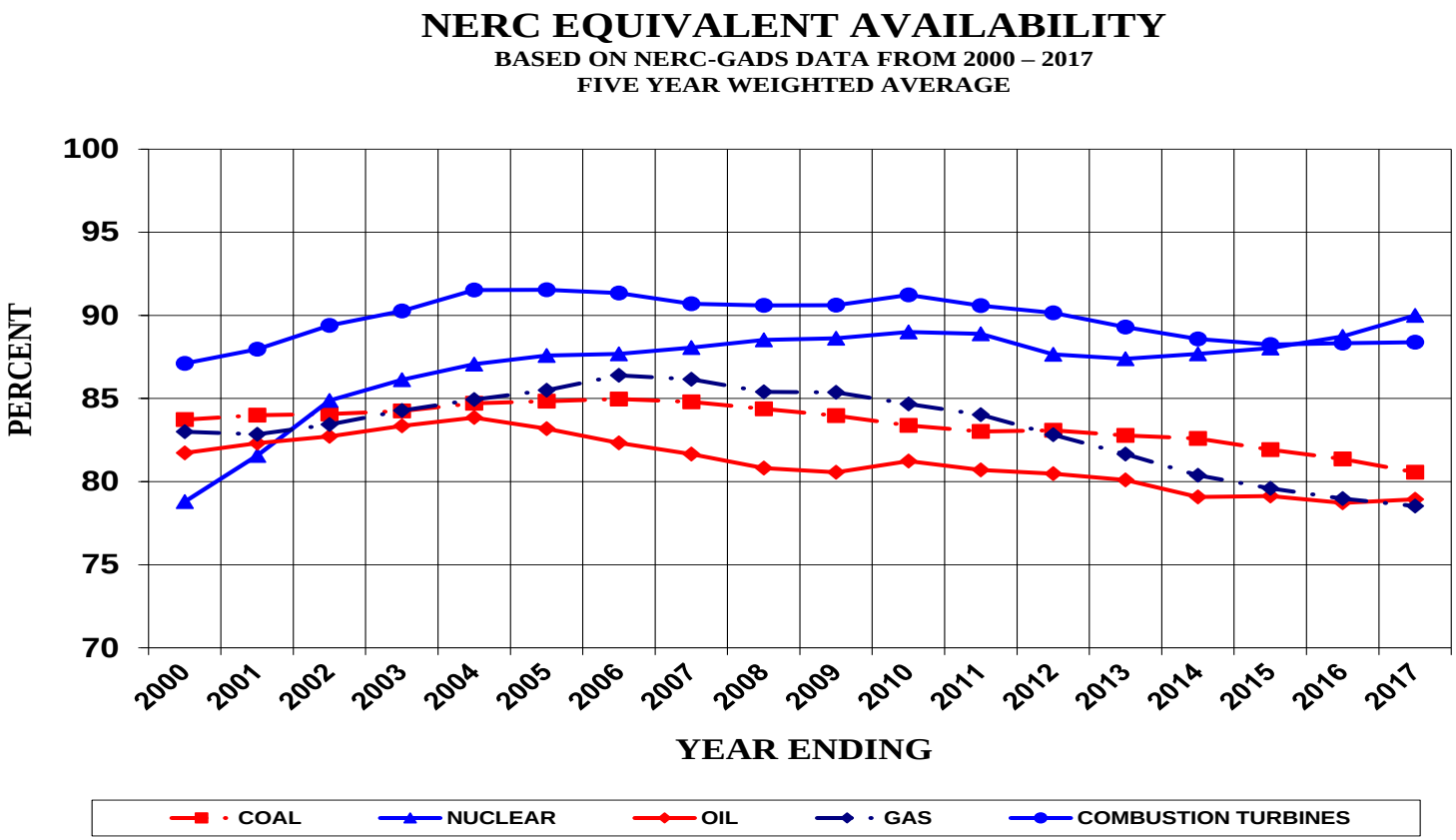


Figure A.9 NERC Five-Year Availability by Fuel



(7) Outages and Summer Maintenance

A second performance parameter to be modeled for each unit is scheduled maintenance. This parameter includes both planned and maintenance outage components. The planned outage (PO) component is obtained from the generator owners. When this information is not available, the unit's historic average planned outage duration is used. Figure A.10 provides a graph of scheduled outage trends over the 2003 through 2017 period for the NYCA generators.

Typically, generator owners do not schedule maintenance during the summer peak period. However, it is highly probable that some units will need to schedule maintenance during this period. Each year, the previous summer capability period is reviewed to determine the scheduled maintenance MW during the previous peak period. An assumption is determined as to how much to model in the current study. For the 2019 IRM Study, a nominal 50 MW of summer maintenance is modeled. The amount is nominally divided equally between Zone J and Zone K. Figure A.11 shows the weekly scheduled maintenance for the 2018 IRM Study compared to this study.

(8) Gas Turbine Ambient De-rate

Operation of combustion turbine units at temperatures above DMNC test temperature results in reduction in output. These reductions in gas turbine and combined cycle capacity output are captured in the GE-MARS model using de-ratings based on ambient temperature correction curves. Based on its review of historical data, the NYISO staff has concluded that the existing combined cycle temperature correction curves are still valid and appropriate. These temperature corrections curves, provided by the Market Monitoring Unit of the NYISO, show unit output versus ambient temperature conditions over a range starting at 60 degrees F to over 100 degrees F. Because generating units are required to report their DMNC output at peak or "design" conditions (an average of temperatures obtained at the time of the transmission district previous four like capability period load peaks), the temperature correction for the combustion turbine units is derived for and applied to temperatures above transmission district peak loads.

(9) Large Hydro De-rates

Hydroelectric projects are modeled as are thermal units, with a probability capacity model based on five years of unit performance. See Capacity Models item 6 above.

Figure A.10 Planned and Maintenance Outage Rates

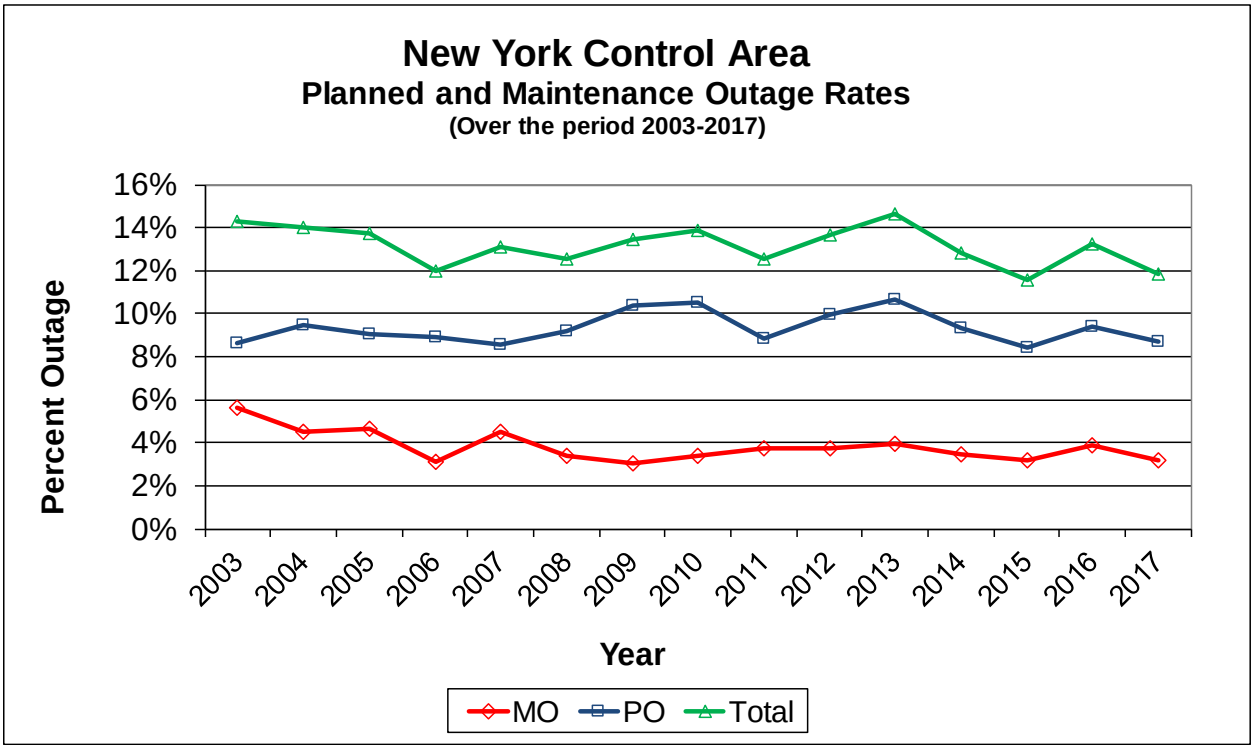
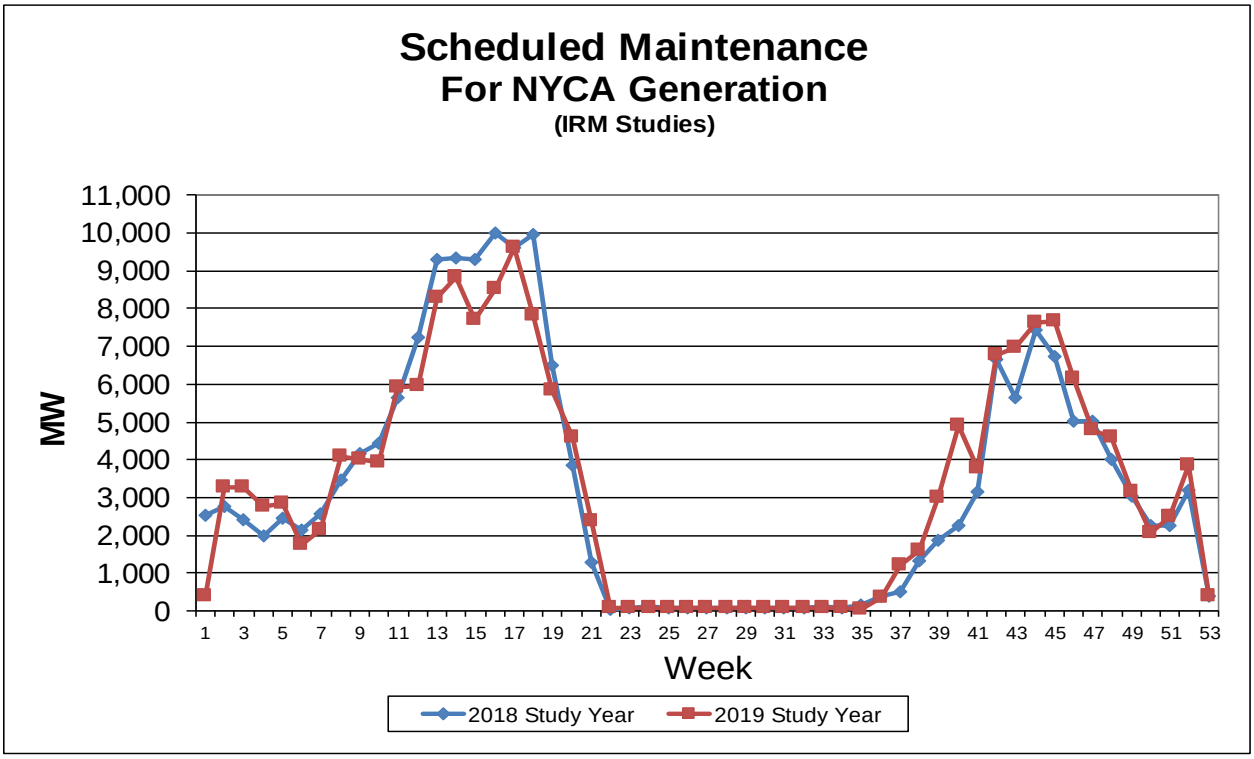


Figure A.11 Scheduled Maintenance



A.3.3 Transmission System Model

A detailed transmission system model is represented in the GE-MARS topology. The transmission system topology, which includes eleven NYCA Zones and four External Control Areas, along with transfer limits, is shown in Figure A.12. The transfer limits employed for the 2019 IRM Study were developed from emergency transfer limit analyses included in various studies performed by the NYISO and based upon input from Transmission Owners and neighboring regions. A list of those studies is shown in Table A.8, below. The transfer limits are further refined by other assessments conducted by the NYISO. The assumptions for the transmission model included in the 2019 IRM Study are listed in Table A.8, which remains largely unchanged from last year's model. The two changes that are captured in this year's model are; 1) the removal of the B and C lines entering Zone J along with a reduction of the grouped interface rating over the A, B, and C lines, and, 2) a reduction of tie capability between Ontario and Zone D to reflect the outage of the Line 33 PAR. These changes estimate the impacts on the system model of these extended outages, which are under further study; however, the results showing actual impacts may not be known prior to next summer's operation.

Forced transmission outages are included in the GE-MARS model for the underground cables that connect New York City and Long Island to surrounding Zones. The GE-MARS model uses transition rates between operating states for each interface, which were calculated based on the probability of occurrence from the historic failure rates and the time to repair. Transition rates into the different operating states for each interface were calculated based on the circuits comprising each interface, including failure rates and repair times for the individual cables, and for any transformer and/or phase angle regulator associated with that cable. The TOs provided updated transition rates for their associated cable interfaces.

Table A.8 Transmission System Model

Parameter	2018 Model Assumptions	2019 Model Assumptions Recommended	Basis for Recommendation
Transmission Lines B and C	1,000 MW combined on the two ties with a 315 MW grouped interface limit on the A, B, and C lines into Zone J	0 MW combined on the two ties with a 105 MW grouped interface limit on the A, B, and C lines into Zone J	An estimate of tie capability reduction due to the extended outage of those lines. Further study is underway.
Line 33 From Ontario to Zone D	300 MW of tie capability in both directions. 1,900 MW limit on a grouped interface leaving Ontario with a 1,650 MW limit entering Ontario	150 MW of tie capability in both directions 1,750 MW limit on a grouped interface leaving Ontario with a 1,500 MW limit entering Ontario	An estimate of tie capability reduction due to the extended outage of the PAR affecting that interface. Further study is underway.
VFT and HTP return lines	Return lines (from the dummy bubble back to PJM) cut across the PJM-SENY grouped interface	Return lines avoid the grouped interface	These return paths were shown to inappropriately affect the total transfer capability.
Interface Limits (other than those identified above)	All changes reviewed and commented on by TPAS	No Changes from the 2018 Model	Based on 2017 Operating Study, 2016 Operations Engineering Voltage Studies, 2016 Reliability Planning Process, and additional analysis including interregional planning initiatives
Cable Forced Outage Rates	All existing Cable EFORs updated for NYC and LI to reflect most recent five-year history	All existing Cable EFORs updated for NYC and LI to reflect most recent five-year history	Based on TO analysis or NYISO analysis where applicable
UDR line Unavailability	Five year history of forced outages	Five year history of forced outages	NYISO/TO review

Figure A.12 shows the transmission system representation for this year's study. Figure A.13 shows the dynamic limits used in the topology.

Figure A.12 2018 IRM Topology

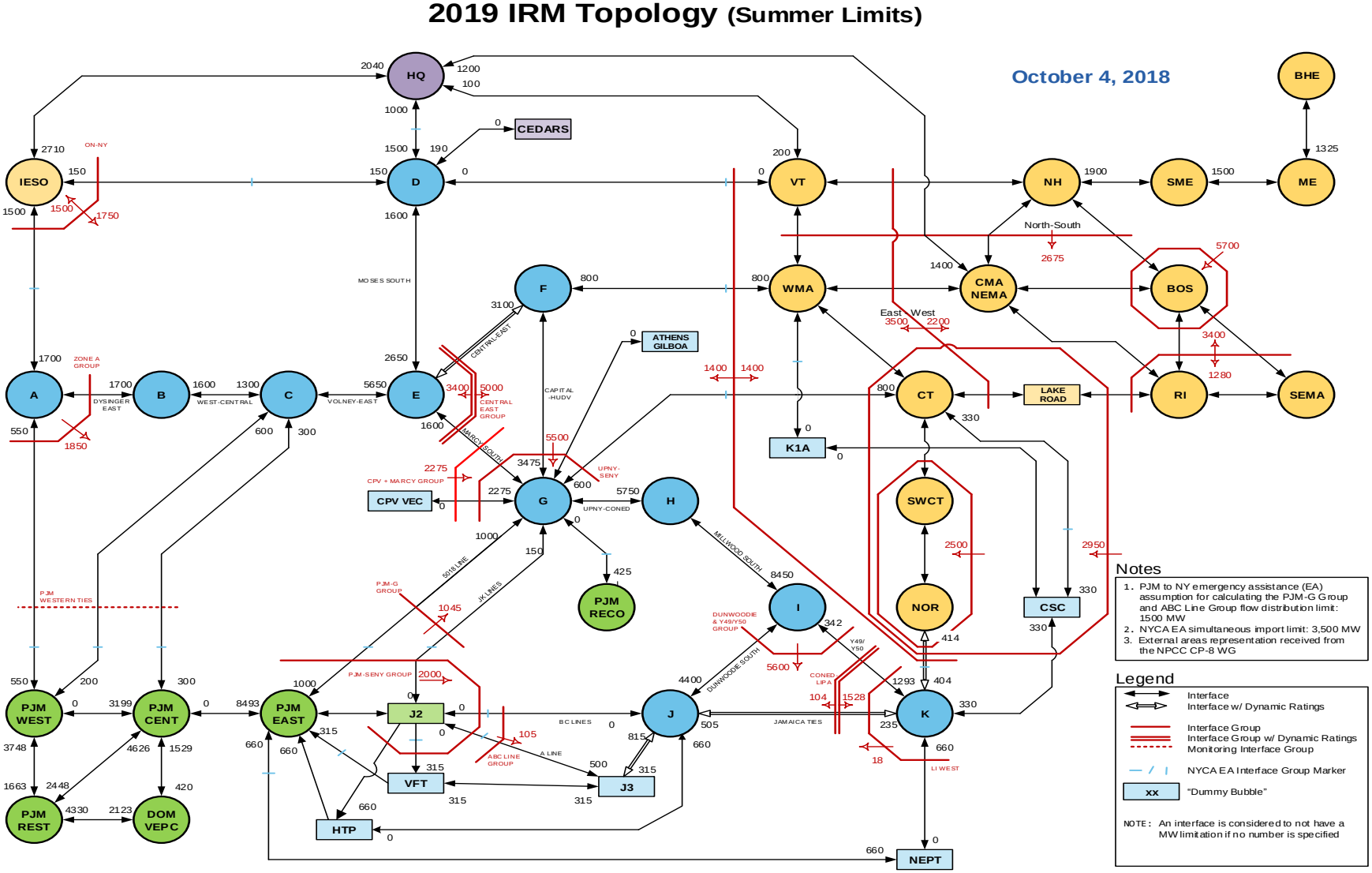


Figure A.13 Dynamic Interface Ratings Information

2019 MARS Topology - Dynamic Limits and Grouping Information

October 19, 2018

Interface Group	Limit	Flow Equation
UPNYSENY	5,500	F_to_G + E_to_G - HUDV_NE + 1.5*ATHENS_G + 0.3*CPVVEC_G
E2G_CPV	2,275	E_to_G + 0.9*CPVVEC_G
LI_WEST	18	K_to_I&J - 0.13*K_NEPT

Central East Voltage Limits, Oswego Complex Units

Depends On:	9MILP1, 9MILP2, FPNUC1, STHIND, OS05, OS06			
Units	E_to_F		E_to_FG	
Available	Fwd	Rev	Fwd	Rev
6	3,100	1,999	5,000	3,400
5	3,050	1,999	4,925	3,400
4	2,990	1,999	4,840	3,400
3	2,885	1,999	4,685	3,400
2	2,770	1,999	4,510	3,400
Otherwise:	2,645	1,999	4,310	3,400

Staten Island Import Limits, AK and Linden CoGen Units

Unit Availability				J_to_J3	
AK02	AK03	LINCOG1	LINCOG2	Fwd	Rev
A	A	A	A	315	200
U	A	A	A	315	500
A	U	A	A	315	700
A	A	U	A	315	500
A	A	A	U	315	500
			Otherwise:	315	815

Long Island Import Limits, Northport

Depends On:	NPRTG1, NPRTS1-4	
Units	LI_NE	
Available	Norwalk to K	K to Norwalk
5	260	414
Otherwise:	404	414

Long Island Import Limits, Barret Steam Units

Depends On:	BARS01, BARS02			
Units	Jamaica Ties		ConEd-LIPA	
Available	J to K	K to J	IJ to K	K to IJ
2	235	505	1,528	104
1	235	390	1,528	74
0	235	236	1,528	0

As can be seen from the figures, the following changes were made to NYCA interface limits:

Table A.9 Interface Limits Updates

	2018		2019		Delta	
Interface	**Forward**	**Reverse**	**Forward**	**Reverse**	**Forward**	**Reverse**
B & C Lines		1000		0		-1000
ABC Line Group	315		105		-210	
Ontario to D	300	300	150	150	-150	-150
Zone A Group	1900	1650	1750	1500	-150	-150

The topology for the 2019 IRM Study features three changes from the topology used in the 2018 IRM Study.

1. <u>Estimate of the impacts of placing the B and C lines out of service</u>
   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. The effects of this removal from service is under study, but the results will not be available in time for the setting of the 2019 Capability Year capacity requirements.

2. <u>Estimate of the impacts of placing the PAR on line 33 out of service</u>
   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 have been reduced from 300 MW down to 150 MW (both directions). The effects of this removal from service are being studied. Those results will not be available in time for the setting of the 2019 Capability Year capacity requirements.

Table A.10 Distribution of Power Transfers between PJM and NY

PJM-NY JOA Flow Distribution (Jan 31, 2017 Filing)	**RECO Load Deliveries**	**PJM-NY Emergency Assistance**
PJM-NY Western Ties	20%	32%
5018 Line	80%	32%
JK Lines	0%	15%
A Line	0%	7%
BC Lines*	0%	0%

*The B and C lines have been removed from service

3. Other Modeling Changes

A review of the topology for this year's 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.

A summary of the above described changes can be found on table A.11 below.

Table A.11 Summary of major changes from 2018 to 2019 IRM topology:

Areas of Focus	Topology Proposal
B and C Lines from PJM entering Zone J	Reduce the capability to zero on the individual B and C ties and set the grouped import limit of the A, B, and C lines from 315 MW down to 105 MW
Line 33 from Ontario to Zone D	Reduce the capability of the Ontario to Zone D ties to 150 MW in both directions. Reduce grouped import limit from and to Ontario by 150 MW
The VFT and HTP return paths to PJM	Create paths from the VFT and HTP dummy bubbles back to PJM that avoid the grouped interface leaving PJM into Southeast New York (SENY)

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

A.3.4 External Area Representations

NYCA reliability largely depends on emergency assistance from its interconnected Control Area neighbors (New England, Ontario, Quebec and PJM) based on reserve sharing agreements with these external Control Areas. Load and capacity models of these Areas are therefore represented in the GE-MARS analyses with data received directly from the Areas and through NPCC sources.

The primary consideration for developing the final load and capacity models for the external Control Areas is to avoid over-dependence on the external Control Areas for emergency capacity support.

For this reason, a limit is placed on the amount of emergency capacity support that the NYISO can receive from external Control Areas in the IRM study. The 3,500 MW value of this limit for this IRM study is based on a recommendation from the ICS and the NYISO that considers the amount of ten-minute reserves that are available in the external Control Areas above an Area's required reserve, along with other factors.

In addition, an external Control Area's LOLE assumed in the IRM Study cannot be lower than its LOLE criteria and its Reserve Margin can be no higher than its minimum requirement. If the Area's reserve margin is lower than its requirement and its LOLE is higher than its criterion, pre-emergency Demand Response can be represented. In other words, the neighboring Areas are assumed to be equally or less reliable than NYCA.

Another consideration for developing models for the external Control Areas is to recognize internal transmission constraints within the external Control Areas that may limit emergency assistance to the NYCA. This recognition is considered implicitly for those Areas that have not supplied internal transmission constraint data. Additionally, EOPs are removed from the external Control Area models.

Finally, the top three summer peak load days of an external Control Area should be specified in the load model to be coincident with the NYCA top three peak load days. The purpose of this is to capture the higher likelihood that there will be considerably

less load diversity between the NYCA and external Control Areas on very hot summer days.

For this study, both New England and PJM continue to be represented as multi-area models, based on data provided by these Control Areas. Ontario and Quebec are represented as single area models. The load forecast uncertainty model for the outside world model was supplied from the external Control Areas.

Modeling of the neighboring Control Areas in the base case in accordance with Policy 5-13 is as follows:

Table A.12 External Area Representations

Parameter	2018 Study Assumption	2019 Study Assumption	Explanation
Capacity Purchases	Grandfathered amounts: PJM – 1080 MW HQ – 1110 MW All contracts model as equivalent contracts	Grandfathered amounts: PJM – 1080 MW HQ – 1110 MW All contracts model as equivalent contracts	Grandfathered Rights, ETCNL, and other FERC identified rights.
Capacity Sales	Long term firm sales of 283.8 MW	Long term firm sales of 279.3 MW	These are long term federally monitored contracts.
External Area Modeling	Single Area representations for Ontario and Quebec. Four areas modeled for PJM. Thirteen zones modeled for New England	Single Area representations for Ontario and Quebec. Five areas modeled for PJM. Thirteen zones modeled for New England	The load and capacity data is provided by the neighboring Areas. This updated data may then be adjusted as described in Policy 5
Reserve Sharing	All NPCC Control Areas have indicated that they will share reserves equally	All NPCC Control Areas have indicated that they will share reserves equally	Per NPCC CP-8 working group assumption.

Table A.13 shows the final reserve margins and LOLEs for the Control Areas external to NYCA. The 2019 external area model was unchanged from 2018 which included a 3,500 MW limit for emergency assistance (EA) imports during any given hour. As per Table 7-1 of the IRM study report, the difference in between the isolated case and the final base case was 8.2% in 2019 VS. 8.0% in 2018 which is consistent with the modeling of the external areas.

Table A.13 Outside World Reserve Margins

Area	2018 Study Reserve Margin	2019 Study Reserve Margin	2018 Study LOLE (Days/Year)	2019 Study LOLE (Days/Year)
Quebec	44.1%*	44.1%*	0.110	0.110
Ontario	34.0%	34.0%	0.105	0.104
PJM	16.1%	16.1%	0.146	0.149
New England	13.8%	13.8%	0.108	0.119

*This is the summer margin.

**This includes 4,347 MW full capacity of wind units.

A.3.5 Emergency Operating Procedures (EOPs)

There are many steps that the system operator can take in an emergency to avoid disconnecting load. EOP steps 2 through 10 listed in Table A.15 were provided by the NYISO based on operator experience. Table A.14 lists the assumptions modeled.

The values in Table A.15 are based on a NYISO forecast that incorporates 2018 (summer) operating results. This forecast is applied against a 2019 peak load forecast of 32,488 MW. The table shows the most likely order that these steps will be initiated. The actual order will depend on the type of the emergency. The amount of assistance that is provided by EOPs related to load, such as voltage reduction, will vary with the load level.

Table A.14 Assumptions for Emergency Operating Procedures

Parameter	2018 Study Assumption	2019 Study Assumption	Explanation
Special Case Resources	July 2017 –1219.1 MW based on registrations and modeled as 867.6 MW of effective capacity. Monthly variation based on historical experience (no Limit on number of calls) *	July 2018 –1309 MW based on registrations and modeled as 903 MW of effective capacity. Monthly variation based on historical experience*	MW registered in the program, discounted to historic availability.
EDRP Resources	July 2017 16 MW registered modeled as 3 MW in July and proportional to monthly peak load in other months. Limit to five calls per month	July 2018 5.5 MW registered modeled as 1.0 MW in July and proportional to monthly peak load in other months. Limit to five calls per month	Those registered for the program, discounted to historic availability. Summer values calculated from July 2018 registrations.
EOP Procedures	609.6 MW of non-SCR/non-EDRP resources	713.4 MW of non-SCR/non-EDRP resources	Based on TO information, measured data, and NYISO forecasts

- The number of SCR calls is limited to 5/month when calculating LOLE based on all 8760 hours.

Table A.15 Emergency Operating Procedures Values

Parameter	Procedure	Effect	MW Value
1	Special Case Resources (SCRs)	Load relief	1309 MW Enrolled/ 903 MW modeled
2	Emergency Demand Response Programs (EDRPs).	Load relief	5.5 MW Enrolled/1 MW Modeled
3	5% manual voltage reduction***	Load relief	66 MW
4	Thirty-minute reserve to zero	Allow operating reserve to decrease to largest unit capacity (10-minute reserve)	655 MW
5	5% remote voltage reduction***	Load relief	401 MW
6	Voluntary industrial curtailment***	Load relief	165.6 MW
7	General public appeals***	Load relief	80.8 MW
8	Emergency Purchases	Load relief	Varies
9	Ten-minute reserve to zero	Allow 10-minute reserve to decrease to zero	1,310 MW
10	Customer disconnections	Load relief	As needed

* *The SCR's are modeled as monthly values. The value for July is 1309 MW.*
*** The EDRPs are modeled as 5.5 MW discounted to 1 MW in July and August and further discounted in other months. They are limited to 5 calls a month.*
**** These EOPs are modeled in the program as a percentage of the hourly peak. The associated MW value is based on a forecast 2019 peak load of 32,488 MW.*

A.3.6 Locational Capacity Requirements

The GE-MARS model used in the IRM study provides an assessment of the adequacy of the NYCA transmission system to deliver assistance from one Zone to another for meeting load requirements. Previous studies have identified transmission constraints into certain Zones that could impact the LOLE of these Zones, as well as the statewide LOLE. To minimize these potential LOLE impacts, these Zones require a minimum portion of their NYCA ICAP requirement, *i.e.,* locational ICAP, which shall be

electrically located within the Zone to ensure that enough energy and capacity are available in that Zone and that NYSRC Reliability Rules are met. For the purposes of the IRM study, Locational ICAP requirements are applicable to two transmission-constrained Zones, New York City and Long Island, and are normally expressed as a percentage of each Zone's annual peak load.

These locational ICAP requirements, recognized by NYSRC Reliability Rule A.2 and monitored by the NYISO, supplement the statewide IRM requirement. This report using the unified methodology determines the minimum locational requirements for different levels of installed reserve. The NYSRC chooses the IRM to be used for the coming year and the NYISO chooses the final value of the locational requirements to be met by the LSEs.

A.3.7 Special Case Resources and Emergency Demand Response Program

Special Case Resources (SCRs) are loads capable of being interrupted, and distributed generators, rated at 100 kW or higher, that are not directly telemetered. SCRs are ICAP resources that only provide energy/load curtailment when activated in accordance with the NYISO Emergency Operating Manual. Performance factors for SCRs are shown below:

Table A.16 SCR Performance

Zones	Forecast SCRs (MW)	Modeled SCRs (MW)	Overall Performance (%)
A - F	655.1	528.2	80.6%
G - I	111.4	71.1	63.8%
J	494.1	274.5	55.5%
K	48.5	28.9	59.7%
NYCA	1309.1	902.7	69.0%

The Emergency Demand Response Program (EDRP) is a separate 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.

GE-MARS model accounts for SCRs and EDRP as EOP steps and will activate these steps to minimize the probability of customer load disconnection. Both GE-MARS and

NYISO operations only activate EOPs in zones where they are capable of being delivered.

SCRs are modeled with monthly values. For the month of July, the registered value is 1309 MW. This value is the result of applying historic growth rates to the latest participation numbers. The effective value of 903 MW is used in the model for this month.

EDRPs are modeled as a 1 MW EOP step in July and August (and they are also further discounted in other months) with a limit of five calls per month. This EOP is discounted from the forecast registered amount of 5.5 MW based on actual experience.

A.4 MARS Data Scrub

A.4.1 GE Data Scrub

General Electric (GE) was asked to review the input data for errors. GE has developed a program called "Data Scrub" which processes the input files and flags data that appears to be out of the ordinary. For example, it can identify a unit with a forced outage rate significantly higher than all the others in that size and type category. If something is found, the NYISO reviews the data and either confirms that it is the right value as is, or institutes an update. The results of this data scrub are shown in Table A.17 for the preliminary base case.

Table A.17 GE MARS Data Scrub

Item	Description	Disposition	Data Change	Post PBC* Affect
1	Unit name changes between 2018 and 2019 study were identified	Name changes were reviewed and accepted	No	N/A
2	Three units added with 0 MW of capacity	Capacities were checked and were correct.	No	N/A
3	Rockville Center (Charles Keller) unit 8 not in list of deactivated units	Unit retired and will be added to assumptions matrix. Retirement correctly captured in model.	No	N/A
4	Stony Book rating not documented in assumptions matrix	Variance in capacity & load are captured but not called out. More description may be needed in report.	No	N/A

Item	Description	Disposition	Data Change	Post PBC* Affect
5	Linden VFT modeled as single unit versus two units last year	Modeling matches data submission.	No	N/A
6	Six units identified with large EFORd change	One unit retired and the other five went through a second review and were found correct in the model	No	N/A
7	Energy, even though not an explicit IRM assumption, appears higher in model than gold book forecast	A known effect of growing historical load shapes to meet future peaks. Initiative underway to study alternatives.	No	N/A

*Preliminary Base Case

A.4.2 NYISO Data Scrub

The NYISO also performs a review of the MARS data independently from GE. Table A.18 shows the results of this review for the preliminary base case.

Table A.18 NYISO MARS Data Scrub

Item	Description	Disposition	Data Change	Post PBC* Affect
1	**MARS version 3.22.6**: The new MARs software has included the final resolution for the random number seeding issue. The IRM change due to this update was slightly larger than anticipated.	Review of the update before the preliminary base case showed that the IRM impact was consistent with the resolution.	No	No
2	**External Systems:** Abnormally large IRM change was found after external systems were updated in the IRM database, even after the Policy 5 adjustment.	The recommendation to retain the previous year's external representation was accepted by the NYSRC. The NYISO and the NYSRC consultants have been charged with investigating this issue for possible resolution in 2019.	N/A	No
3	**Generation:** The BTM:NG units were included at their net capacity values in the preliminary base case.	The Final base case was corrected to model the units at their full capacity value with the host loads reflected in the load shapes.	Yes	Yes
4	**Transition Rate:** Incorrect transition rates of the Dunwoodie South cable were found due to non-zero values for transitions from the 8th state.	Corrected in the parametric study case before the preliminary base case.	Yes	No

Item	Description	Disposition	Data Change	Post PBC* Affect
5	**DSM Shapes:** Unexpected IRM impact was observed after study year was changed from 2018 to 2019 in the parametric study.	All DSM shapes for wind, solar, ROR hydro, and Biomass units have been manually shifted one day later to align with the calendar shift of load shapes.	Yes	No
6	**DSM Shapes:** An incorrect calculation formula was found in the creation of the new wind unit in zone A.	The correct calculation showed a 5 MW improvement in the peak hours output, and a negligible improvement in IRM.	Yes	Negligible

*Preliminary Base Case

** N/A because changes were made prior to the PBC

A.4.3 Transmission Owner Data Scrub

In addition to the above reviews, two transmission owners scrub the data and assumptions from a masked database provided. All of their findings reiterated the previous findings. Table A.19 shows their unique results.

Table A.19 Transmission Owner Data Scrub

Item	Description	Disposition	Data Change	Post PBC* Affect
	TO identified items	No additional observations were found in TO submittals		

*Preliminary Base Case

Appendix B

Details of Study Results

B. Details for Study Results

B.1 Sensitivity Results

Table B.1 summarizes the 2019 Capability Year IRM requirements under a range of assumption changes from those used for the base case. The base case utilized the computer simulation, reliability model, and assumptions described in Appendix A. The sensitivity cases determined the extent of how the base case required IRM would change for assumption modifications, either one at a time, or in combination. The methodology used to conduct the sensitivity cases was to start with the preliminary base case 16.9 % IRM results then add or remove capacity from all zones in NYCA until the NYCA LOLE approached criterion. The values in Table B.1 are the sensitivity results adjusted to the 16.8% final base case. A full tan 45 analysis was conducted for cases 9 and 11.

Table B.1 Sensitivity Case Results

Case	Description	IRM (%)	NYC (%)	LI (%)
0	**2019 Final Base Case**	16.8	82.7	101.5
	This is the Base Case technical results derived from knee of the IRM-LCR curve. All other sensitivity cases are performed as described above.			
1	**NYCA Isolated**	25.0	88.4	109.2
	This case examines a scenario where the 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 (Free Flow System)**	14.4	81.0	99.3
	This case represents the "Free-Flow" NYCA case where internal transmission constraints are eliminated and measures the impact of transmission constraints on statewide IRM requirements.			
3	**No Load Forecast Uncertainty**	9.2	77.3	94.4
	This scenario represents "perfect vision" for 2019 peak loads, assuming that the forecast peak loads for NYCA have a 100% probability of occurring. The results of this evaluation help to quantify the effects of weather on IRM requirements.			
4	**Remove all wind generation**	12.0	83.4	102.4
	Freeze J & K at base levels and adjust capacity in the upstate zones. This shows the impact that the wind generation has on the IRM requirement.			
5	**No SCRs & no EDRPs**	13.9	79.2	101.6

Case	Description	IRM (%)	NYC (%)	LI (%)
	Shows the impact of SCRs and EDRPs on IRM.			
6	**Remove CPV valley from service**	17.0	83.2	101.9
	Remove the addition of CPV Valley (678 MW) from the base case due to air permit uncertainty.			
7	**Limit Emergency Assistance from PJM to all of NYCA to 1500 MW**	16.8	82.7	101.5
	This case uses a grouped interface of all PJM to NYCA import ties and restricts the grouping to a limit of 1500 MW			
8	**Remove the 3500 MW EA Limit into NYCA**	16.5	82.5	101.2
	Remove the 3500 MW Emergency Assistance grouped limit entering NYCA from its neighbors. UDRs remain in New York.			
9	**Return the B and C lines to service (tan 45)**	17.0	80.0	100.9
	Return the B and C lines to service by increasing the grouped interface rating from 105 MW to 315 MW. Also, restore the B and C tie capability from 0 MW to 1,000 MW.			
10	**Remove public appeals from model**	17.2	83.2	102.1
	Remove 80 MW of public appeals from the EOP steps in the model.			
11	**Incorporate Quebec to New England wheel (tan 45)**	17.1	82.8	101.7
	Reduce the HQ to zone D rating by 300 MW and increase to NE to Zone F by 300 MW to account for this capacity transaction.			
12	**Combine Cedars and Quebec areas**	16.9	82.7	101.6
	In anticipation of the 2020 IRM, create one Area with both Quebec and the Cedars combined. Increase tie capability to 1690 MW.			

B.2 Impacts of Environmental Regulations

B.2.1 Regulatory Policy Activities

Federal, state and local government regulatory programs may impact the operation and reliability of the BPTF. Compliance with state and federal regulatory initiatives and permitting requirements may require investment by the owners of New York's existing thermal power plants. If the owners of those plants must make considerable investments, the cost of these investments could impact whether they remain available in the NYISO's markets and therefore potentially affect the reliability of the BPTF. The purpose of this section is to review the status of regulatory programs and

their potential grid impacts. The following regulatory programs – each at various points in the development and implementation – are summarized below:

PUBLIC POLICY INITIATIVE	POLICY GOAL	POLICYMAKING ENTITY	NY GRID RESOURCE IMPACTS
Clean Energy Standard (CES)	50% of energy consumed in New York State generated from renewable resources by **2030**.	New York State Public Service Commission (PSC) / New York State Energy Research and Development Authority (NYSERDA)	About **17,000 MW** of new, largely intermittent capacity to enter grid and markets.
New York City Residual Oil Elimination	Eliminate combustion of fuel oil numbers 6 and 4 in New York City by **2020 and 2025**, respectively.	New York City	About **3,000 MW** of installed capacity could be affected.
Offshore Wind Development	Develop 2,400 MW of offshore wind capacity by **2030.**	New York State Public Service Commission (PSC) / New York State Energy Research and Development Authority (NYSERDA)	As much as **2,400 MW** of new intermittent capacity interconnecting to the grid in southeastern New York by 2030.
Part 251: Carbon Dioxide Emissions Limits	Establish restrictions on carbon dioxide emissions for fossil fuel-fired facilities in New York by **2020**.	New York State Department of Environmental Conservation (DEC)	**1,000 MW** of coal-fired capacity expected to deactivate or re-power.
Regional Greenhouse Gas Initiative (RGGI)	Reduce carbon dioxide emissions cap by 30% from **2020 to 2030** and expand applicability to currently exempt "peaking units" below current 25 MW threshold.	New York and other RGGI states	**26,100 MW** of installed capacity participate in RGGI.
Smog-Forming Pollutants Rule Proposal	Reduce ozone-contributing pollutants associated with New York State-based peaking unit generation.	New York State Department of Environmental Conservation (DEC)	DEC proposal is under development. There is nearly **3,500 MW** of peaking unit capacity in New York State.
Storage Deployment Target	Reduce costs and install storage capacity by **2025.**	New York State Public Service Commission (PSC) / New York State Energy Research and Development Authority (NYSERDA) / New York Power Authority (NYPA)	Installation of **1,500 MW** of battery storage capacity.
U.S. Clean Water Act	Adoption of "Best Technology Available for Cooling Water Intake" to protect aquatic biota.	U.S. Environmental Protection Agency / New York State Department of Environmental Conservation (DEC)	**16,900 MW** of installed capacity must achieve compliance upon licensing renewal.

B.2.2 Clean Energy Standard

In August 2016, the New York State Public Service Commission (PSC) adopted a Clean Energy Standard (CES), requiring that 50% of the energy consumed in New York State be generated from renewable resources by 2030 (50-by-30 goal). Under the CES, electric utilities and others serving load in New York State are responsible for securing a defined percentage of the load they serve from eligible renewable and nuclear resources. The load serving entities will comply with the CES by either procuring qualifying credits or making alternative compliance payments.

In order to achieve the 50-by-30 goal, the PSC determined that approximately 70,500 GWh of total renewable energy will need to be generated by 2030 – including approximately 29,200 GWh of new renewable energy production in addition to existing levels of production at the time the order was adopted. Currently, the New York State Energy Research and Development Authority (NYSERDA) is offering long-term (20 year) contracts for Renewable Energy Credits (RECs) associated with eligible renewable resources and administer the procurement of Zero-Emissions Credits (ZECs) associated with the generation from eligible nuclear plants.

B.2.3 New York City Residual Oil Elimination

New York City passed legislation in December 2017 that will prohibit the combustion of fuel oil Numbers 6 and 4 within the borders of New York City by 2020 and 2025, respectively. The rule is expected to impact the fuel of about 3,000 MW of generation in New York City. Many generators in New York City that are connected to the local gas distribution network are required by reliability rules to maintain alternative fuel combustion capabilities – most notably oil. The rule is intended to provide assurance that system reliability can be maintained in the event of gas supply interruptions during high demand periods. Typically, these interruptions occur in the winter months when gas is needed for heating.

These generators will need to decide whether to invest in the fuel storage, and handling equipment necessary to convert their facilities to comply with the law. While oil accounts for a relatively small percentage of the total energy production in New York State on an annual basis, it is often called upon to fuel generation during critical periods when severe cold weather limits access to natural gas and system demand is typically higher than normal for the season. Dual-fuel capability serves as both an important tool in meeting reliability, and as an effective economic hedge against high natural gas prices during periods of high demand for natural gas as a heating fuel.

B.2.4 Offshore Wind Development

Recently, the New York PSC issued an order providing that NYSERDA, with the involvement of the Long Island Power Authority (LIPA) and the New York Power Authority (NYPA) will procure offshore wind RECs (ORECs) from developers for up to 2,400 MW of offshore wind. NYSERDA has issued a request for proposals for an initial procurement of 800 MW.

B.2.5 Part 251: Carbon Dioxide Emissions Limits

Governor Cuomo has directed the New York State Department of Environmental Conservation (DEC) to implement carbon dioxide emissions restrictions from fossil fuel-fired generators. As a result, the roughly 1,100 MW of remaining coal-fired generation capacity in New York State is expected to exit the market in 2020. New York's coal-fired generation accounted for less than 1% of the total energy produced in the state in 2017. Upon receipt of deactivation notices from the generators, the NYISO's planning processes will assess whether such deactivations trigger potential reliability needs.

B.2.6 Regional Greenhouse Gas Initiative (RGGI)

RGGI is a multi-state carbon dioxide emissions cap-and-trade initiative that requires affected generators to procure emissions allowances enabling them to emit carbon dioxide. Through a program review in 2017, the RGGI states agreed to several program changes, including a 30% cap reduction between 2020 and 2030, essentially ratcheting down the availability of allowances to generators that produce greenhouse gases.

Tighter requirements through RGGI are not likely to trigger reliability concerns, but again, when combined with the numerous public policy action described in this section, raises uncertainties about the makeup of the future grid.

B.2.7 Smog-Forming Pollutants Rule Proposal

In his 2018 State of the State address, Governor Cuomo announced that the DEC will propose emissions requirements intended to reduce emissions of smog-forming pollutants from peaking units, and as much as 3,500 MW could be affected.
The NYISO will continue to monitor the development of new emissions rules that may impact the operation of peaking units.

B.2.8 Storage Deployment Target

The State of the State address also called for a $200 million investment from the New York Green Bank to support the development and deployment of up to 1,500 MW of energy storage capacity by 2025. The goal of the initiative is to drive down costs for storage while strategically deploying storage resources in locations where they best serve the needs of the grid. The New York State Energy Research and Development Authority (NYSERDA) will initially focus on storage pilots and activities that reduce barriers to deploying storage, including permitting, customer acquisition costs, interconnection, and financing costs.

B.2.9 U.S. Clean Water Act: Best Technology Available for Plant Cooling Water Intake

The U.S. Environmental Protection Agency (EPA) has issued a new Clear Water Act Section 316b rule providing standards for the design and operation of power plant cooling systems. This rule will be implemented by New York State Department of Environmental Conservation (DEC), which has finalized a policy for the implementation of the Best Technology Available (BTA) for plant cooling water intake structures. This policy is activated upon renewal of a plant's water withdrawal and discharge permit. Based upon a review of current information available from the DEC, the NYISO has estimated that 16,900 MW of nameplate capacity is affected by this rule, some of which could be required to undertake major system retrofits, including closed cycle cooling systems.

B.3 Frequency of Implementing Emergency Operating Procedures

In all cases, it was assumed that the EOPs are implemented as required to meet the 0.1 days/year criterion. For the base case, the study shows that approximately 6.2 remote controlled voltage reductions per year would be implemented to meet the once in 10 years disconnection criterion. The expected frequency for each of the EOPs for the base case is provided in Table B.2.

Table B.2 Implementation of EOP steps

Step	EOP	Expected Implementation (Days/Year)
1	Require SCRs	9.3
2	Require EDRPs	6.6
3	5% manual voltage reduction	6.4
4	30-minute reserve to zero	6.3
5	5% remote controlled voltage reduction	6.2
6	Voluntary load curtailment	4.3
7	Public appeals	3.5
8	Emergency purchases	3.2
9	10-minute reserve to zero	3.0
10	Customer disconnections	0.1

Appendix C

ICAP to UCAP Translations

C. ICAP to UCAP Translation

The NYISO administers the capacity requirements to all loads in the NYCA. In 2002, the NYISO adopted the Unforced Capacity (UCAP) methodology for determining system requirements, unit ratings and market settlements. The UCAP methodology uses individual generating unit data for output and availability to determine an expected level of resources that can be considered for system planning, operation and marketing purposes. EFORd is developed from this process for each generating unit and applied to the units Dependable Maximum Net Capability (DMNC) test value to determine the resulting level of UCAP.

Individual unit EFORd factors are taken in aggregate on both a Statewide and Locational basis and used to effectively "translate" the IRM and LCRs previously determined in the GE-MARS Analysis in terms of ICAP, into an equivalent UCAP basis.

Table C.1 summarizes historical values (since 2000) for NYCA capacity parameters including Base Case IRMs, approved IRMs, UCAP requirements, and NYISO Approved LCRs (for NYC, LI and G-J).

Table C.1 Historical NYCA Capacity Parameters

Capability Year	Base Case IRM (%)	EC Approved IRM (%)	NYCA Equivalent UCAP Requirement (%)	NYISO Approved NYC LCR (%)	NYISO Approved LI LCR (%)	NYISO Approved LHV LCR (%)
2000	15.5	18.0		80.0	107.0	
2001	17.1	18.0		80.0	98.0	
2002	18.0	18.0		80.0	93.0	
2003	17.5	18.0		80.0	95.0	
2004	17.1	18.0	11.9	80.0	99.0	
2005	17.6	18.0	12.0	80.0	99.0	
2006	18.0	18.0	11.6	80.0	99.0	
2007	16.0	16.5	11.3	80.0	99.0	
2008	15.0	15.0	8.4	80.0	94.0	
2009	16.2	16.5	7.2	80.0	97.5	
2010	17.9	18.0	6.1	80.0	104.5	
2011	15.5	15.5	6.0	81.0	101.5	
2012	16.1	16.0	5.4	83.0	99.0	
2013	17.1	17.0	6.6	86.0	105.0	
2014	17.0	17.0	6.4	85.0	107.0	88.0
2015	17.3	17.0	7.0	83.5	103.5	90.5
2016	17.4	17.5	6.2	80.5	102.5	90.0
2017	18.1	18.0	7.0	81.5	103.5	91.5
2018	18.2	18.2	8.1	80.5	103.5	94.5

C.1 NYCA and NYC and LI Locational Translations

In the "Installed Capacity" section of the NYISO Web site3, NYISO Staff regularly post summer and winter Capability Period ICAP and UCAP calculations for NYCA Locational Areas and Transmission District Loads. This information has been compiled and posted since 2006.

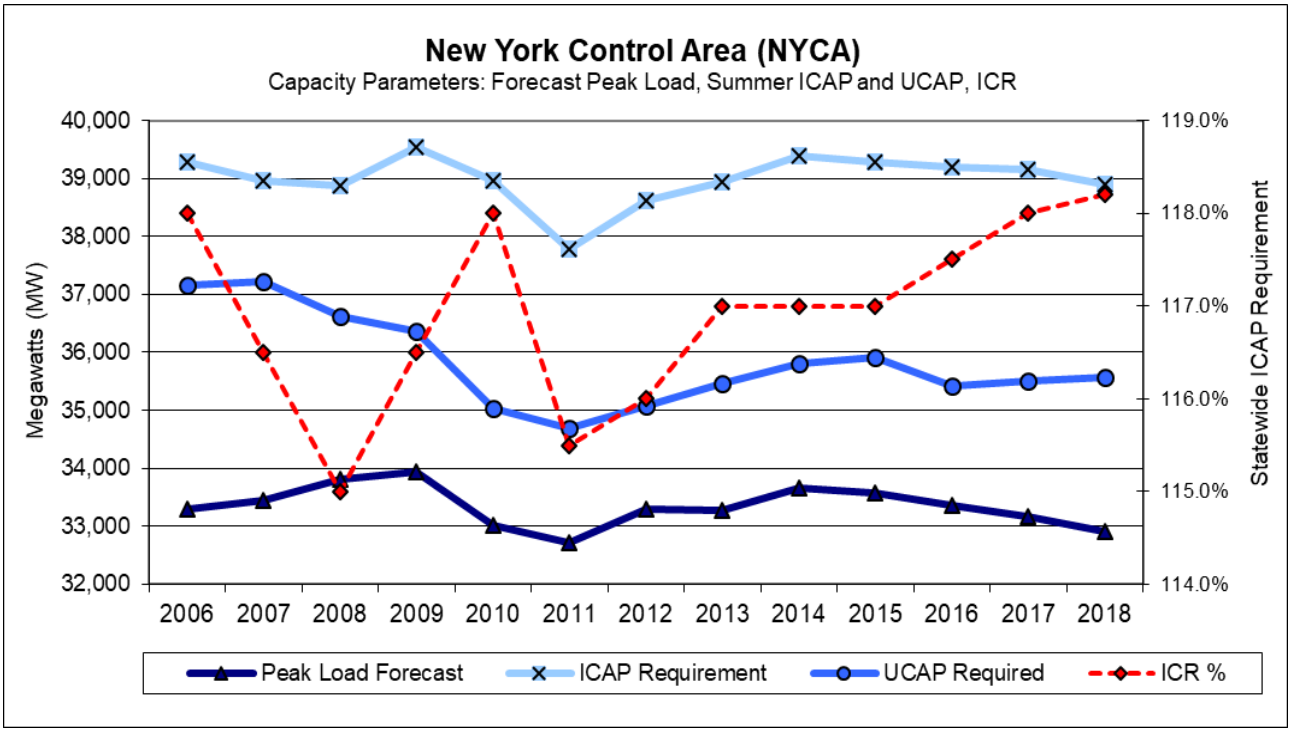
Locational ICAP/UCAP calculations are produced for NYC, LI, G-J Locality and the entire NYCA. Exhibits C.1.1 through C.1.4 summarizes the translation of ICAP requirements to UCAP requirements for these areas. The charts and tables included in these exhibits utilize data from the 2006 through 2018 summer capability periods.

This data reflects the interaction and relationships between the capacity parameters used this study, including Forecast Peak Load, ICAP Requirements, De-rating Factors, UCAP Requirements, IRMs, and LCRs. Since these parameters are so inextricably linked to each other, the graphical representation also helps one more easily visualize the annual changes in capacity requirements.

C.1.1 New York Control Area ICAP to UCAP Translation

Table C.2 NYCA ICAP to UCAP Translation

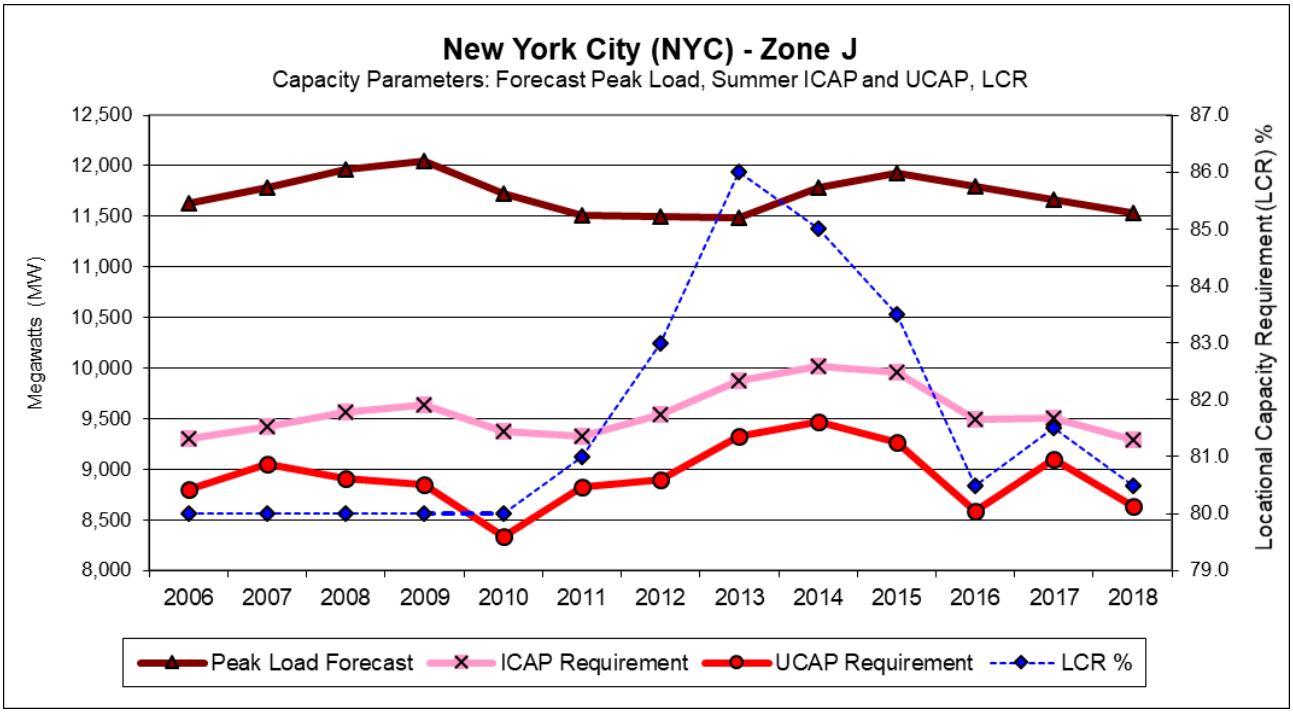
Year	Forecast Peak Load (MW)	Installed Capacity Requirement (%)	Derate Factor	ICAP Requirement (MW)	UCAP Requirement (MW)	Effective UCAP (%)
2006	33,295	118.0	0.0543	39,288	37,154	111.6
2007	33,447	116.5	0.0446	38,966	37,228	111.3
2008	33,809	115.0	0.0578	38,880	36,633	108.4
2009	33,930	116.5	0.0801	39,529	36,362	107.2
2010	33,025	118.0	0.1007	38,970	35,045	106.1
2011	32,712	115.5	0.0820	37,783	34,684	106.0
2012	33,295	116.0	0.0918	38,622	35,076	105.4
2013	33,279	117.0	0.0891	38,936	35,467	106.6
2014	33,666	117.0	0.0908	39,389	35,812	106.4
2015	33,567	117.0	0.0854	39,274	35,920	107.0
2016	33,359	117.5	0.0961	39,197	35,430	106.2
2017	33,178	118.0	0.0929	39,150	35,513	107.0
2018	32,903	118.2	0.0856	38,891	35,562	108.1



C.1.2 New York City ICAP to UCAP Translation

Table C.3 New York City ICAP to UCAP Translation

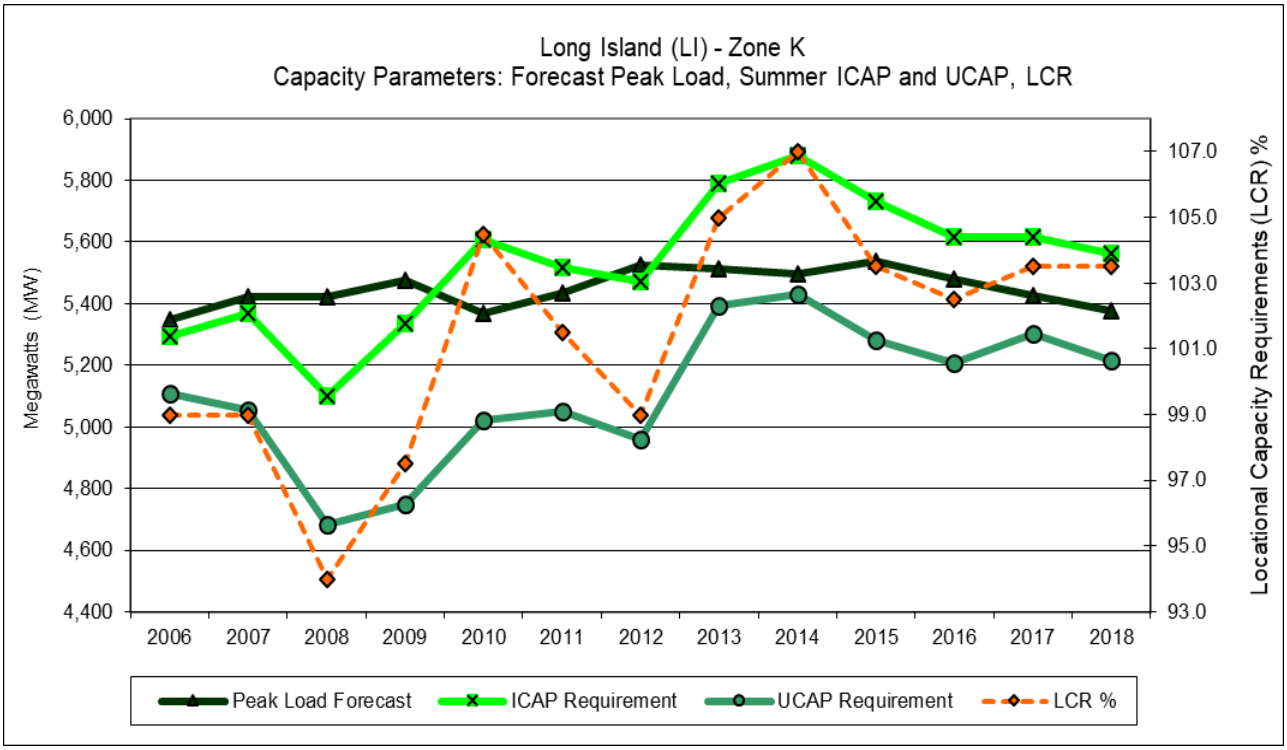
Year	Forecast Peak Load (MW)	Locational Capacity Requirement (%)	Derate Factor	ICAP Requirement (MW)	UCAP Requirement (MW)	Effective UCAP (%)
2006	11,628	80.0	0.0542	9,302	8,798	75.7
2007	11,780	80.0	0.0388	9,424	9,058	76.9
2008	11,964	80.0	0.0690	9,571	8,911	74.5
2009	12,050	80.0	0.0814	9,640	8,855	73.5
2010	11,725	80.0	0.1113	9,380	8,336	71.1
2011	11,514	81.0	0.0530	9,326	8,832	76.7
2012	11,500	83.0	0.0679	9,545	8,897	77.4
2013	11,485	86.0	0.0559	9,877	9,325	81.2
2014	11,783	85.0	0.0544	10,015	9,471	80.4
2015	11,929	83.5	0.0692	9,961	9,272	77.7
2016	11,794	80.5	0.0953	9,494	8,589	72.8
2017	11,670	81.5	0.0437	9,511	9,095	77.9
2018	11,539	80.5	0.0709	9,289	8,630	74.8



C.1.3 Long Island ICAP to UCAP Translation

Table C.4 Long Island ICAP to UCAP Translation

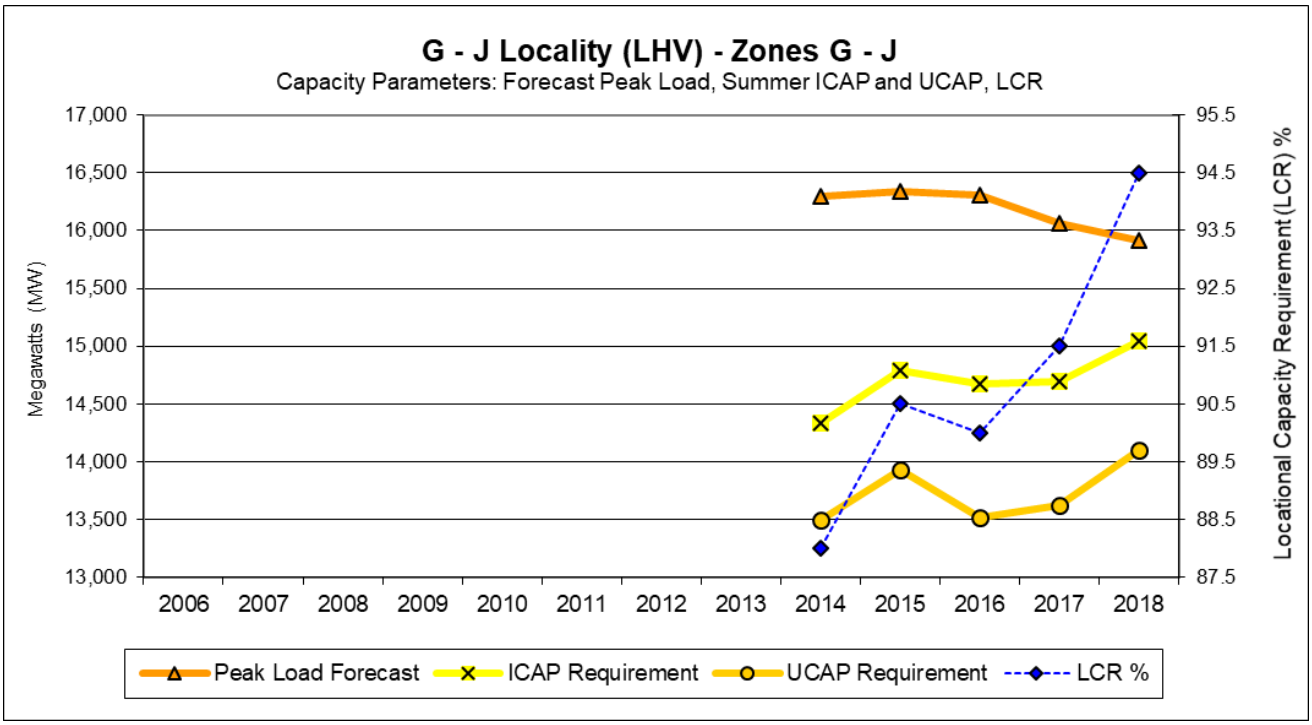
Year	Forecast Peak Load (MW)	Locational Capacity Requirement (%)	Derate Factor	ICAP Requirement (MW)	UCAP Requirement (MW)	Effective UCAP (%)
2006	5,348	99.0	0.0348	5,295	5,110	95.6
2007	5,422	99.0	0.0580	5,368	5,056	93.3
2008	5,424	94.0	0.0811	5,098	4,685	86.4
2009	5,474	97.5	0.1103	5,337	4,749	86.8
2010	5,368	104.5	0.1049	5,610	5,021	93.5
2011	5,434	101.5	0.0841	5,516	5,052	93.0
2012	5,526	99.0	0.0931	5,470	4,961	89.8
2013	5,515	105.0	0.0684	5,790	5,394	97.8
2014	5,496	107.0	0.0765	5,880	5,431	98.8
2015	5,539	103.5	0.0783	5,733	5,284	95.4
2016	5,479	102.5	0.0727	5,615	5,207	95.0
2017	5,427	103.5	0.0560	5,617	5,302	97.7
2018	5,376	103.5	0.0628	5,564	5,214	97.0



C.1.4 GHIJ ICAP to UCAP Translation

Table C.5 GHIJ ICAP to UCAP Translation

Year	Forecast Peak Load (MW)	Locational Capacity Requirement (%)	Derate Factor	ICAP Requirement (MW)	UCAP Requirement (MW)	Effective UCAP (%)
2014	16,291	88.0	0.0587	14,336	13,495	82.8
2015	16,340	90.5	0.0577	14,788	13,934	85.3
2016	16,309	90.0	0.0793	14,678	13,514	82.9
2017	16,061	91.5	0.0731	14,696	13,622	84.8
2018	15,918	94.5	0.0626	15,042	14,100	88.6

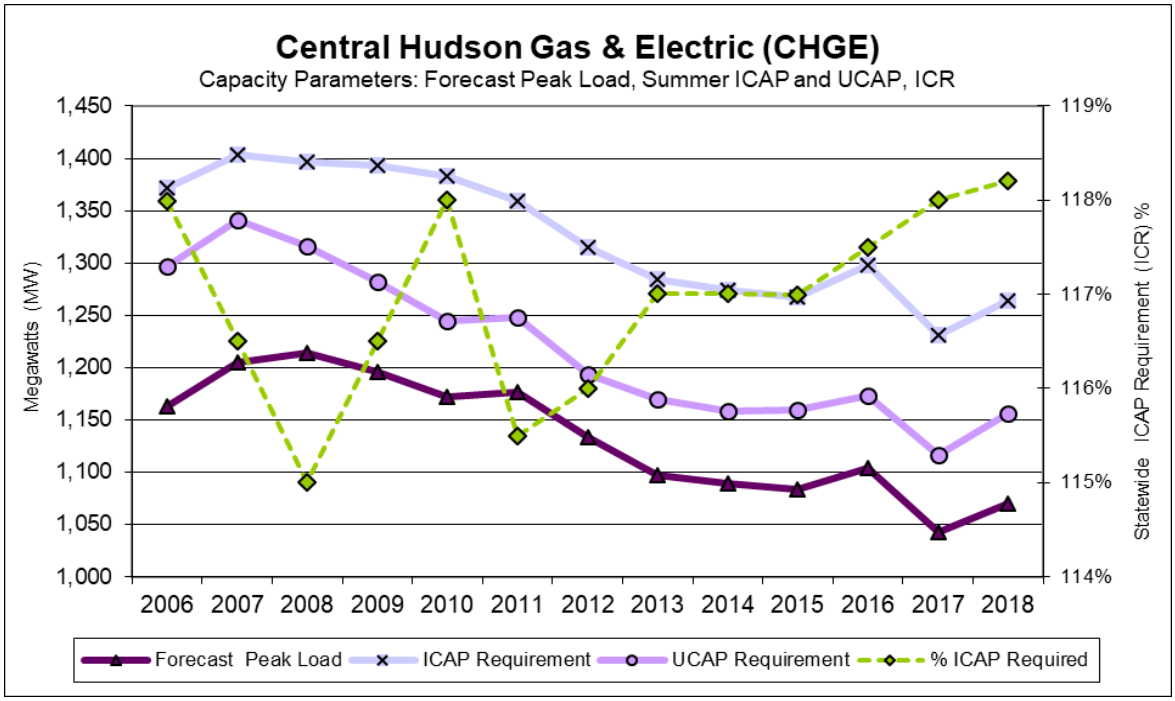


C.2 Transmission Districts ICAP to UCAP Translation

C.2.1 Central Hudson Gas & Electric

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

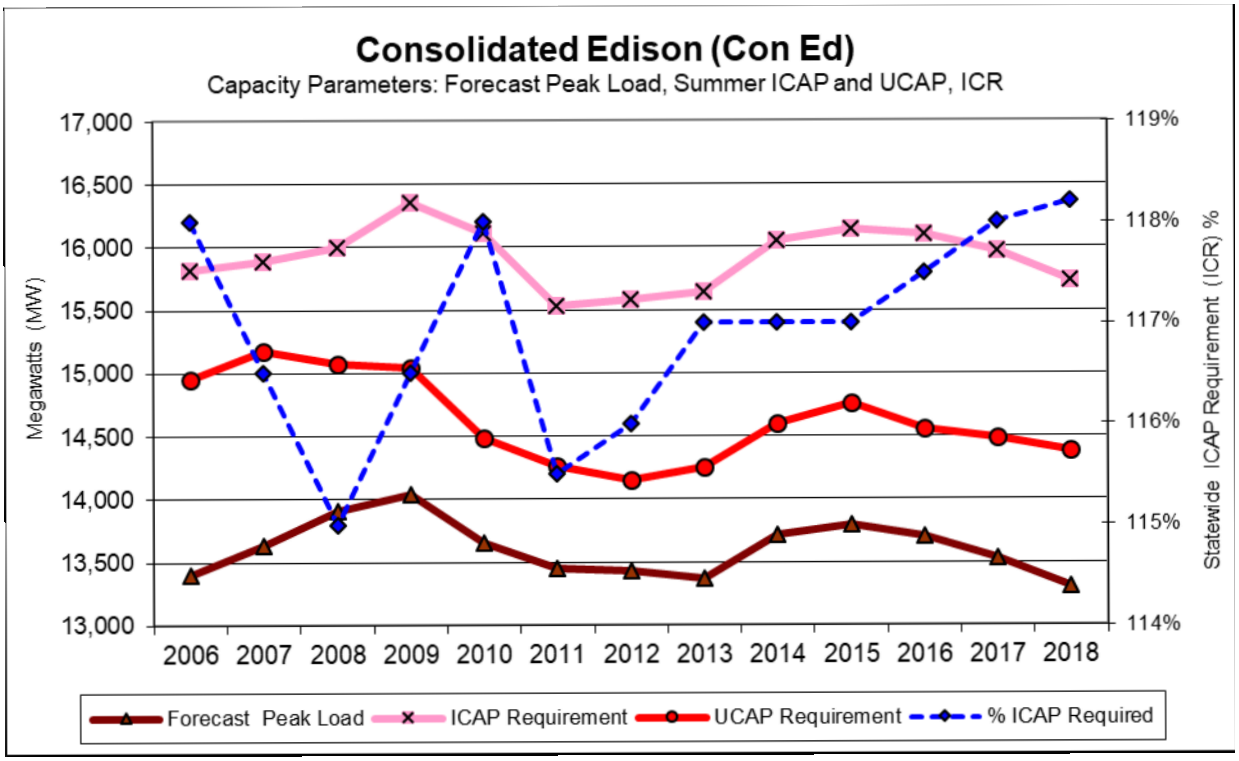
Year	Forecast Peak Load (MW)	ICAP Requirement (MW)	UCAP Requirement (MW)	%ICAP of Forecast Peak	%UCAP of Forecast Peak
2006	1,162.5	1,371.7	1,297.3	118.0%	111.6%
2007	1,205.0	1,403.8	1,341.2	116.5%	111.3%
2008	1,214.1	1,396.2	1,315.5	115.0%	108.4%
2009	1,196.3	1,393.7	1,282.1	116.5%	107.2%
2010	1,172.3	1,383.3	1,244.0	118.0%	106.1%
2011	1,176.9	1,359.3	1,247.9	115.5%	106.0%
2012	1,133.3	1,314.6	1,193.9	116.0%	105.3%
2013	1,097.5	1,284.1	1,169.7	117.0%	106.6%
2014	1,089.2	1,274.4	1,158.7	117.0%	106.4%
2015	1,083.6	1,267.8	1,159.5	117.0%	107.0%
2016	1,104.2	1,297.4	1,172.7	117.5%	106.2%
2017	1,043.1	1,230.9	1,116.5	118.0%	107.0%
2018	1,069.7	1,264.4	1,156.2	118.2%	108.1%



C.2.2 Consolidated Edison (Con Ed)

Table C.7 Con Ed ICAP to UCAP Translation

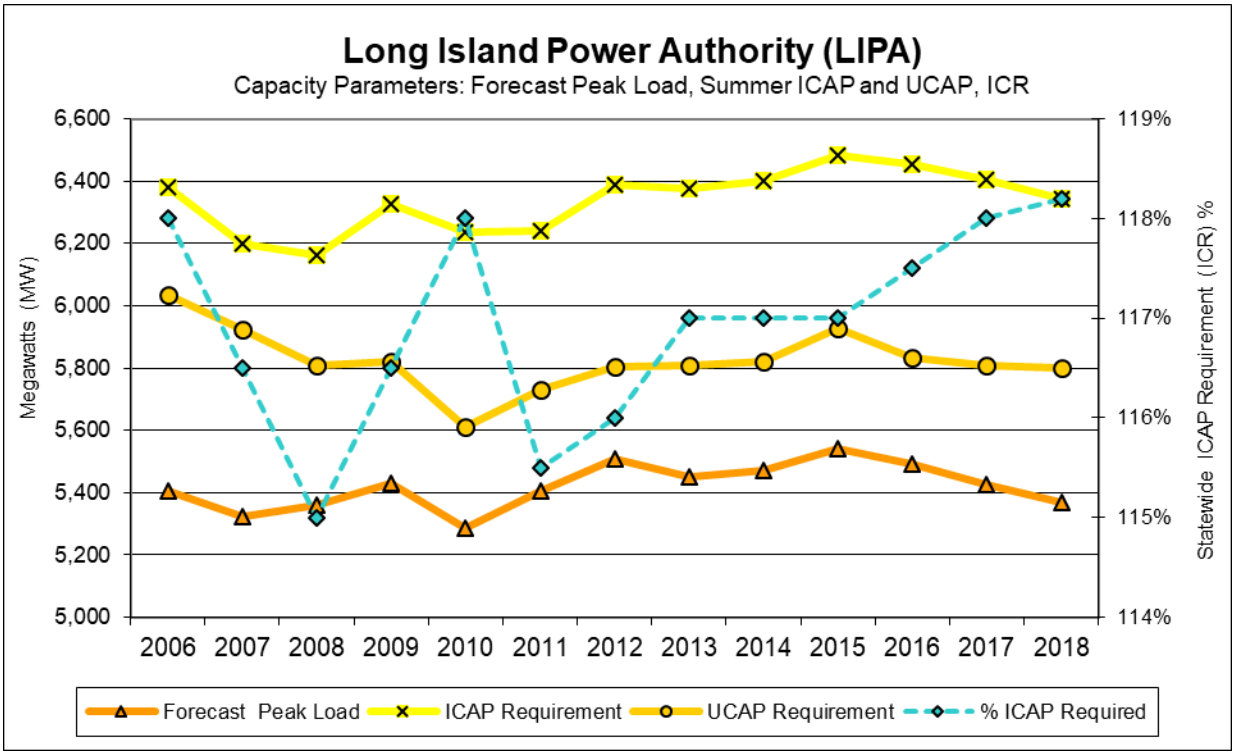
Year	Forecast Peak Load (MW)	ICAP Requirement (MW)	UCAP Requirement (MW)	%ICAP of Forecast Peak	%UCAP of Forecast Peak
2006	13,400.0	15,812.0	14,953.4	118.0%	111.6%
2007	13,633.6	15,883.1	15,174.7	116.5%	111.3%
2008	13,911.1	15,997.8	15,073.1	115.0%	108.4%
2009	14,043.0	16,360.1	15,049.6	116.5%	107.2%
2010	13,654.9	16,112.8	14,490.2	118.0%	106.1%
2011	13,450.5	15,535.3	14,261.4	115.5%	106.0%
2012	13,430.5	15,579.4	14,149.2	116.0%	105.4%
2013	13,370.8	15,643.8	14,250.0	117.0%	106.6%
2014	13,718.7	16,050.9	14,593.5	117.0%	106.4%
2015	13,793.0	16,137.8	14,759.6	117.0%	107.0%
2016	13,704.6	16,102.9	14,555.4	117.5%	106.2%
2017	13,534.0	15,970.1	14,486.5	118.0%	107.0%
2018	13,309.6	15,732.0	14,385.3	118.2%	108.1%



C.2.3 Long Island Power Authority (LIPA)

Table C.8 LIPA ICAP to UCAP Translation

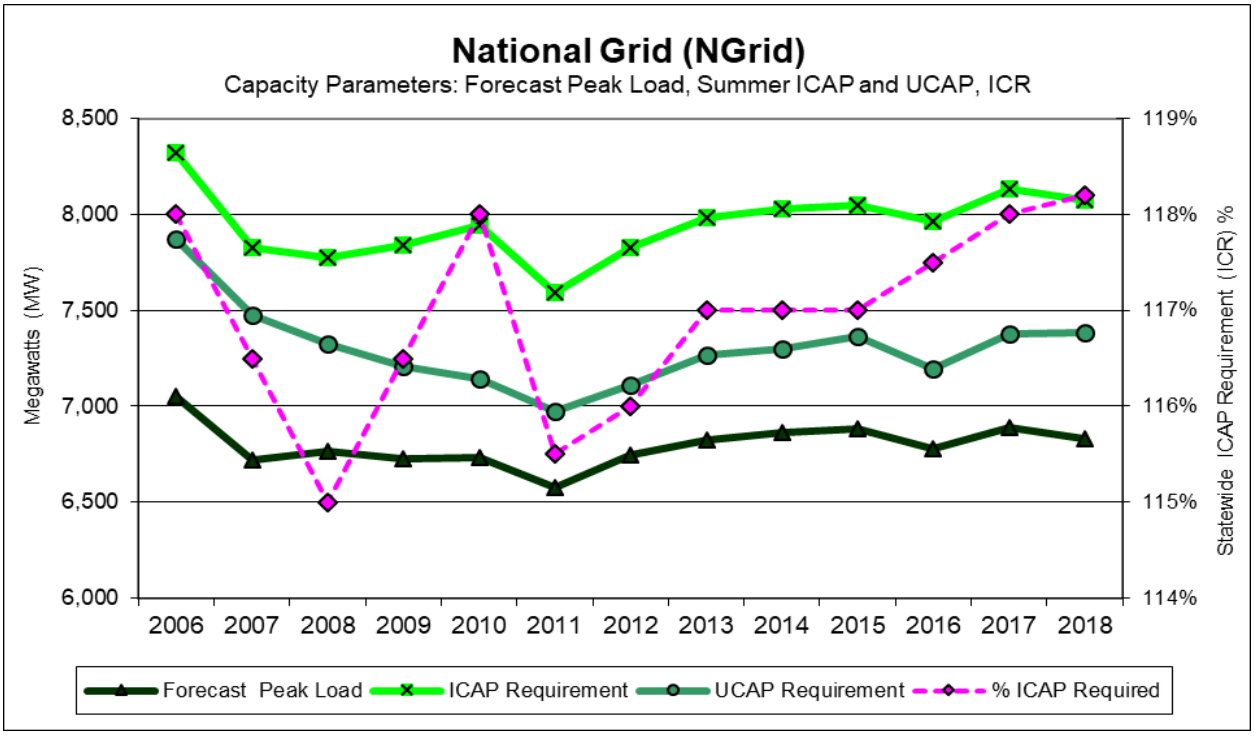
Year	Forecast Peak Load (MW)	ICAP Requirement (MW)	UCAP Requirement (MW)	%ICAP of Forecast Peak	%UCAP of Forecast Peak
2006	5,406.2	6,379.3	6,032.9	118.0%	111.6%
2007	5,321.8	6,199.9	5,923.4	116.5%	111.3%
2008	5,358.9	6,162.7	5,806.5	115.0%	108.4%
2009	5,431.7	6,327.9	5,821.1	116.5%	107.2%
2010	5,286.0	6,237.5	5,609.4	118.0%	106.1%
2011	5,404.3	6,242.0	5,730.1	115.5%	106.0%
2012	5,508.3	6,389.6	5,803.1	116.0%	105.4%
2013	5,448.9	6,375.2	5,807.2	117.0%	106.6%
2014	5,470.1	6,400.0	5,818.9	117.0%	106.4%
2015	5,541.3	6,483.3	5,929.7	117.0%	107.0%
2016	5,491.3	6,452.3	5,832.2	117.5%	106.2%
2017	5,427.2	6,404.1	5,809.1	118.0%	107.0%
2018	5,368.1	6,345.1	5,802.0	118.2%	108.1%



C.2.4 National Grid (NGRID)

Table C.9 NGRID ICAP to UCAP Translation

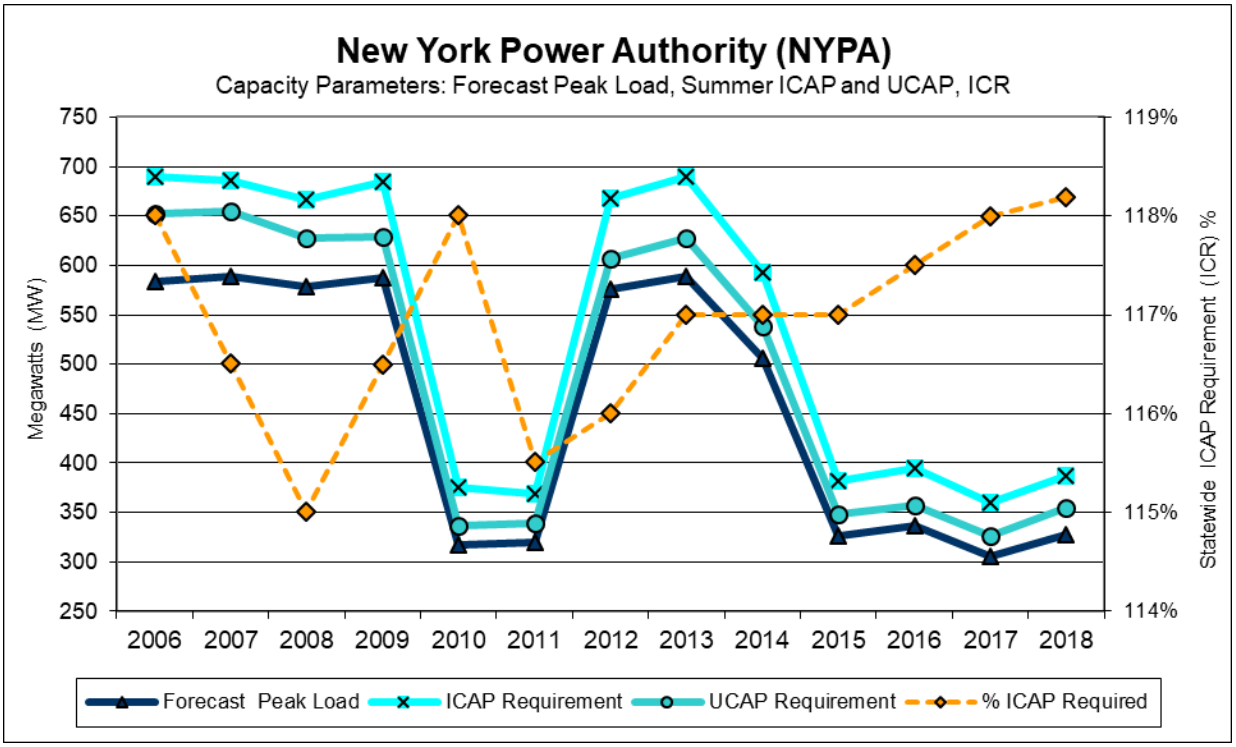
Year	Forecast Peak Load (MW)	ICAP Requirement (MW)	UCAP Requirement (MW)	%ICAP of Forecast Peak	%UCAP of Forecast Peak
2006	7,051.6	8,320.9	7,869.1	118.0%	111.6%
2007	6,718.6	7,827.2	7,478.1	116.5%	111.3%
2008	6,762.5	7,776.9	7,327.3	115.0%	108.4%
2009	6,728.4	7,838.6	7,210.7	116.5%	107.2%
2010	6,732.1	7,943.9	7,144.0	118.0%	106.1%
2011	6,574.7	7,593.8	6,971.1	115.5%	106.0%
2012	6,749.1	7,828.9	7,110.3	116.0%	105.4%
2013	6,821.3	7,980.9	7,269.8	117.0%	106.6%
2014	6,861.9	8,028.4	7,299.4	117.0%	106.4%
2015	6,880.3	8,049.9	7,362.5	117.0%	107.0%
2016	6,776.0	7,961.8	7,196.7	117.5%	106.2%
2017	6,891.4	8,131.9	7,376.4	118.0%	107.0%
2018	6,833.0	8,076.6	7,385.2	118.2%	108.1%



C.2.5 New York Power Authority (NYPA)

Table C.10 NYPA ICAP to UCAP Translation

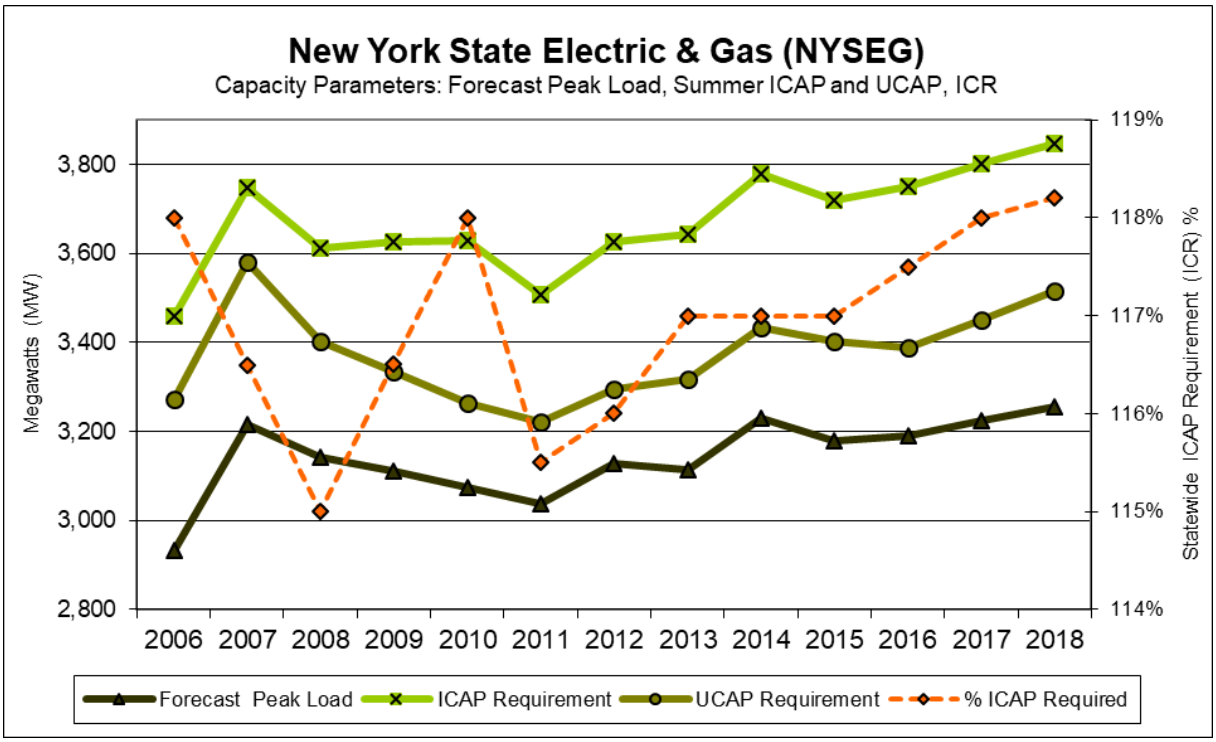
Year	Forecast Peak Load (MW)	ICAP Requirement (MW)	UCAP Requirement (MW)	%ICAP of Forecast Peak	%UCAP of Forecast Peak
2006	584.2	689.4	651.9	118.0%	111.6%
2007	588.2	685.3	654.7	116.5%	111.3%
2008	579.1	666.0	627.5	115.0%	108.4%
2009	587.2	684.1	629.3	116.5%	107.2%
2010	317.6	374.8	337.0	118.0%	106.1%
2011	319.7	369.3	339.0	115.5%	106.0%
2012	576.1	668.3	606.9	116.0%	105.3%
2013	589.3	689.5	628.1	117.0%	106.6%
2014	506.3	592.4	538.6	117.0%	106.4%
2015	325.8	381.2	348.6	117.0%	107.0%
2016	336.0	394.8	356.9	117.5%	106.2%
2017	305.0	359.9	326.5	118.0%	107.0%
2018	327.6	387.2	354.1	118.2%	108.1%



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

Table C.11 NYSEG ICAP to UCAP Translation

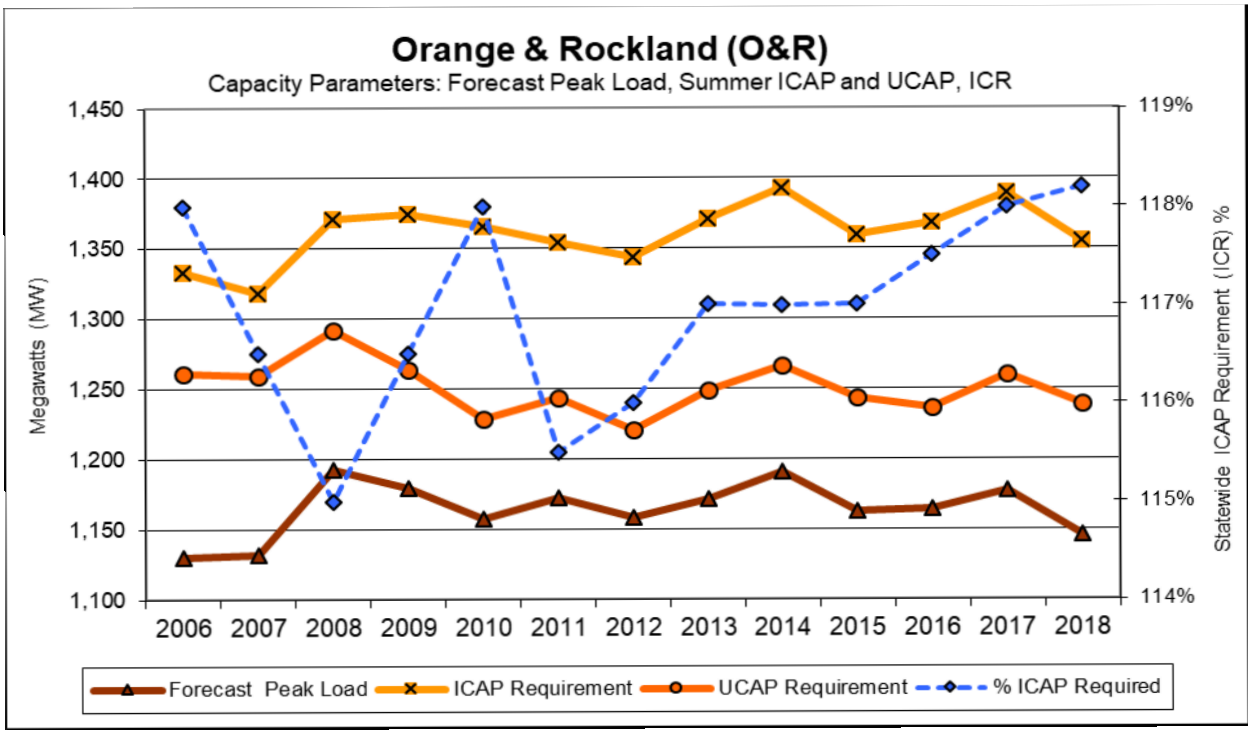
Year	Forecast Peak Load (MW)	ICAP Requirement (MW)	UCAP Requirement (MW)	%ICAP of Forecast Peak	%UCAP of Forecast Peak
2006	2,931.5	3,459.2	3,271.3	118.0%	111.6%
2007	3,216.9	3,747.7	3,580.5	116.5%	111.3%
2008	3,141.1	3,612.3	3,403.5	115.0%	108.4%
2009	3,111.8	3,625.3	3,334.9	116.5%	107.2%
2010	3,075.0	3,628.5	3,263.1	118.0%	106.1%
2011	3,037.0	3,507.7	3,220.1	115.5%	106.0%
2012	3,126.7	3,627.0	3,294.0	116.0%	105.4%
2013	3,113.4	3,642.7	3,318.1	117.0%	106.6%
2014	3,229.1	3,778.1	3,435.0	117.0%	106.4%
2015	3,179.8	3,720.4	3,402.7	117.0%	107.0%
2016	3,191.6	3,750.1	3,389.7	117.5%	106.2%
2017	3,222.9	3,803.0	3,449.7	118.0%	107.0%
2018	3,254.0	3,846.2	3,517.0	118.2%	108.1%



C.2.7 Orange & Rockland (O & R)

Table C.12 O & R ICAP to UCAP Translation

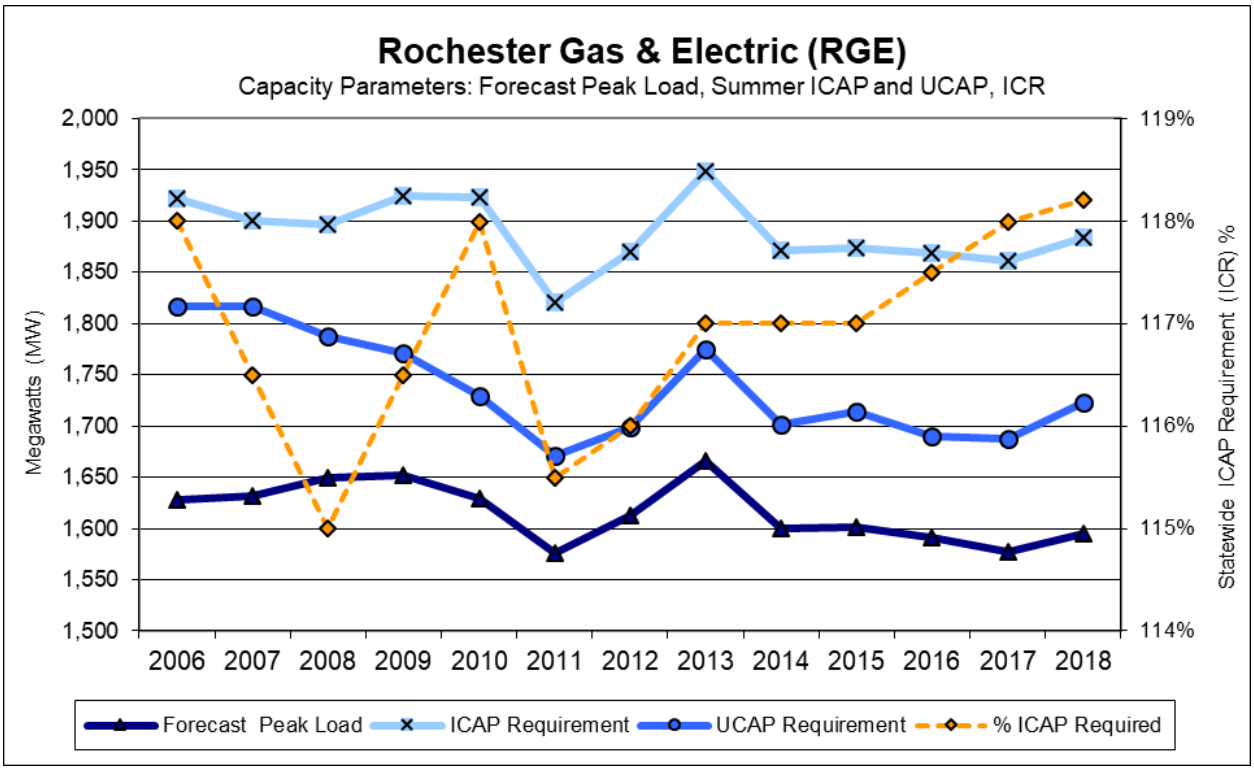
Year	Forecast Peak Load (MW)	ICAP Requirement (MW)	UCAP Requirement (MW)	%ICAP of Forecast Peak	%UCAP of Forecast Peak
2006	1,130.0	1,333.4	1,261.0	118.0%	111.6%
2007	1,131.5	1,318.2	1,259.4	116.5%	111.3%
2008	1,192.3	1,371.1	1,291.9	115.0%	108.4%
2009	1,179.5	1,374.1	1,264.0	116.5%	107.2%
2010	1,157.4	1,365.7	1,228.2	118.0%	106.1%
2011	1,172.7	1,354.5	1,243.4	115.5%	106.0%
2012	1,158.3	1,343.6	1,220.3	116.0%	105.4%
2013	1,171.7	1,370.9	1,248.7	117.0%	106.6%
2014	1,190.8	1,393.2	1,266.7	117.0%	106.4%
2015	1,162.2	1,359.8	1,243.7	117.0%	107.0%
2016	1,164.3	1,368.1	1,236.6	117.5%	106.2%
2017	1,177.3	1,389.2	1,260.2	118.0%	107.0%
2018	1,146.2	1,354.8	1,238.8	118.2%	108.1%



C.2.8 Rochester Gas & Electric (RGE)

Table C.13 RGE ICAP to UCAP Translation

Year	Forecast Peak Load (MW)	ICAP Requirement (MW)	UCAP Requirement (MW)	%ICAP of Forecast Peak	%UCAP of Forecast Peak
2006	1,628.5	1,921.6	1,817.3	118.0%	111.6%
2007	1,631.8	1,901.0	1,816.3	116.5%	111.3%
2008	1,649.4	1,896.8	1,787.2	115.0%	108.4%
2009	1,652.3	1,924.9	1,770.7	116.5%	107.2%
2010	1,629.7	1,923.0	1,729.4	118.0%	106.1%
2011	1,576.4	1,820.7	1,671.4	115.5%	106.0%
2012	1,612.3	1,870.3	1,698.6	116.0%	105.4%
2013	1,665.7	1,948.9	1,775.2	117.0%	106.6%
2014	1,599.6	1,871.5	1,701.6	117.0%	106.4%
2015	1,601.3	1,873.5	1,713.5	117.0%	107.0%
2016	1,590.8	1,869.2	1,689.6	117.5%	106.2%
2017	1,576.9	1,860.7	1,687.9	118.0%	107.0%
2018	1,594.3	1,884.5	1,723.1	118.2%	108.1%



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

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

For a wind farm or turbine, the nameplate capacity is the ICAP while the effective capacity is equal to the UCAP value. Seasonal variability and geographic location are factors that also affect wind resource availability. The effective capacity of wind generation can be either calculated statistically directly from historical hourly wind generation outputs, and/or by using the following information:

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

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

Another measure of a wind generator’s contribution to resource adequacy is its effective capacity which is its expected output during the summer peak hours of 2 p.m. to 6 p.m. for the months of June through August. The effective capacity value for wind generation in New York is based on actual hourly plant output over the previous five-year period – 2013 through 2017 for this year’s study, for new units the zonal hourly averages or averages for nearby units will be used. Wind shapes years are selected randomly from those years for each simulation year.

Appendix D

Glossary of Terms

D. Glossary

Term	Definition
Availability	A measure of time a generating unit, transmission line, or other facility can provide service, whether or not it actually is in service. Typically, this measure is expressed as a percent available for the period under consideration.
Bubble	A symbolic representation introduced for certain purposes in the GE-MARS model as an area that may be an actual zone, multiple areas or a virtual area without actual load.
Capability Period	Six (6) month periods which are established as follows: (1) from May 1 through October 31 of each year ("Summer Capability Period"); and (2) from November 1 of each year through April 30 of the following year ("Winter Capability Period"); or such other periods as may be determined by the Operating Committee of the NYISO. A summer capability period followed by a winter capability period shall be referred to as a "Capability Year." Each capability period shall consist of on-peak and off-peak periods.
Capacity	The rated continuous load-carrying ability, expressed in megawatts (“MW”) or megavolt-amperes (“MVA”) of generation, transmission or other electrical equipment.
Contingency	An actual or potential unexpected failure or outage of a system component, such as a generator, transmission line, circuit breaker, switch, or other electrical element. A contingency also may include multiple components, which are related by situations leading to simultaneous component outages.
Control Area (CA)	An electric system or systems, bounded by interconnection metering and telemetry, capable of controlling generation to maintain its interchange schedule with other control areas and contributing to frequency regulation of the interconnection.
Demand	The rate at which energy must be generated or otherwise provided to supply an electric power system.
Emergency	Any abnormal system condition that requires automatic or immediate, manual action to prevent or limit loss of transmission facilities or generation resources that could adversely affect the reliability of an electric system.
External Installed Capacity (External ICAP)	Installed capacity from resources located in control areas outside the NYCA that must meet certain NYISO requirements and criteria in order to qualify to supply New York LSEs.
Firm Load	The load of a Market Participant that is not contractually interruptible. Interruptible Load – The load of a Market Participant that is contractually interruptible.
Generation	The process of producing electrical energy from other forms of energy; also, the amount of electric energy produced, usually expressed in kilowatt-hours (kWh) or megawatt-hours (MWh).

Term	Definition
Installed Capacity (ICAP)	Capacity of a facility accessible to the NYS Bulk Power System, that is capable of supplying and/or reducing the demand for energy in the NYCA for the purpose of ensuring that sufficient energy and capacity is available to meet the reliability rules.
Installed Capacity Requirement (ICR)	The annual statewide requirement established by the NYSRC in order to ensure resource adequacy in the NYCA.
Installed Reserve Margin (IRM)	That capacity above firm system demand required to provide for equipment forced and scheduled outages and transmission capability limitations.
Interface	The specific set of transmission elements between two areas or between two areas comprising one or more electrical systems.
Load	The electric power used by devices connected to an electrical generating system. (IEEE Power Engineering)
Load Relief	Load reduction accomplished by voltage reduction or load shedding or both. Voltage reduction and load shedding, as defined in this document, are measures by order of the NYISO.
Load Shedding	The process of disconnecting (either manually or automatically) pre-selected customers' load from a power system in response to an abnormal condition to maintain the integrity of the system and minimize overall customer outages. Load shedding is a measure undertaken by order of the NYISO. If ordered to shed load, transmission owner system dispatchers shall immediately comply with that order. Load shall normally all be shed within 5 minutes of the order.
Load Serving Entity (LSE)	In a wholesale competitive market, Central Hudson Gas & Electric Corporation, Consolidated Edison Company of New York, Inc., Long Island Power Authority ("LIPA"), New York State Electric & Gas Corporation, Niagara Mohawk Power Corporation, Orange & Rockland Utilities, Inc., and Rochester Gas and Electric Corporation, the current forty-six (46) members of the Municipal Electric Utilities Association of New York State, the City of Jamestown, Rural Electric Cooperatives, the New York Power Authority ("NYPA"), any of their successors, or any entity through regulatory requirement, tariff, or contractual obligation that is responsible for supplying energy, capacity and/or ancillary services to retail customers within New York State.
Locational Capacity Requirement (LCR)	Due to transmission constraints, that portion of the NYCA ICAP requirement that must be electrically located within a zone, in order to ensure that sufficient energy and capacity are available in that zone and that NYSRC Reliability Rules are met. Locational ICAP requirements are currently applicable to three transmission constrained zones, New York City, Long Island, and the Lower Hudson Valley, and are normally expressed as a percentage of each zone's annual peak load.
New York Control Area (NYCA)	The control area located within New York State which is under the control of the NYISO. See Control Area.

Term	Definition
New York Independent System Operator (NYISO)	The NYISO is a not-for-profit organization formed in 1998 as part of the restructuring of New York State's electric power industry. Its mission is to ensure the reliable, safe and efficient operation of the State's major transmission system and to administer an open, competitive and nondiscriminatory wholesale market for electricity in New York State.
New York State Bulk Power System (NYS Bulk Power System or BPS)	The portion of the bulk power system within the New York Control Area, generally comprising generating units 300 MW and larger, and generally comprising transmission facilities 230 kV and above. However, smaller generating units and lower voltage transmission facilities on which faults and disturbances can have a significant adverse impact outside of the local area are also part of the NYS Bulk Power System.
New York State Reliability Council, LLC (NYSRC)	An organization established by agreement (the "NYSRC Agreement") by and among Central Hudson Gas & Electric Corporation, Consolidated Edison Company of New York, Inc., LIPA, New York State Electric & Gas Corporation, Niagara Mohawk Power Corporation, Orange & Rockland Utilities, Inc., Rochester Gas and Electric Corporation, and the New York Power Authority, to promote and maintain the reliability of the Bulk Power System, and which provides for participation by Representatives of Transmission Owners, sellers in the wholesale electric market, large commercial and industrial consumers of electricity in the NYCA, and municipal systems or cooperatively-owned systems in the NYCA, and by unaffiliated individuals.
New York State (NYS) Transmission System	The entire New York State electric transmission system, which includes: (1) the transmission facilities under NYISO operational control; (2) the transmission facilities requiring NYISO notification, and; (3) all remaining facilities within the NYCA.
Operating Limit	The maximum value of the most critical system operation parameter(s) which meet(s): (a) pre-contingency criteria as determined by equipment loading capability and acceptable voltage conditions; (b) stability criteria; (c) post-contingency loading and voltage criteria.
Operating Procedures	A set of policies, practices, or system adjustments that may be automatically or manually implemented by the system operator within a specified time frame to maintain the operational integrity of the interconnected electric systems.
Operating Reserves	Resource capacity that is available to supply energy, or curtailable load that is willing to stop using energy, in the event of emergency conditions or increased system load, and can do so within a specified time period.
Reserves	In normal usage, reserve is the amount of capacity available in excess of the demand.
Resource	The total contributions provided by supply-side and demand-side facilities and/or actions.
Stability	The ability of an electric system to maintain a state of equilibrium during normal and abnormal system conditions or disturbances.
Thermal Limit	The maximum power flow through a particular transmission element or interface, considering the application of thermal assessment criteria.

Term	Definition
Transfer Capability	The measure of the ability of interconnected electrical systems to reliably move or transfer power from one area to another over all transmission lines (or paths) between those areas under specified system conditions.
Transmission District	The geographic area served by the NYCA investor-owned transmission owners and LIPA, as well as customers directly interconnected with the transmission facilities of NYPA.
Transmission Owner	Those parties who own, control and operate facilities in New York State used for the transmission of electric energy in interstate commerce. Transmission owners are those who own, individually or jointly, at least 100 circuit miles of 115 kV or above in New York State and have become a signatory to the TO/NYISO Agreement.
Unforced Capacity:	The measure by which Installed Capacity Suppliers will be rated, in accordance with formulae set forth in the ISO Procedures, to quantify the extent of their contribution to satisfy the NYCA Installed Capacity Requirement, and which will be used to measure the portion of that NYCA Installed Capacity Requirement for which each LSE is responsible.
Voltage Limit	The maximum power flow through some particular point in the system considering the application of voltage assessment criteria.
Voltage Reduction	A means of achieving load reduction by reducing customer supply voltage, usually by 3, 5, or 8 percent. If ordered by the NYISO to go into voltage reduction, Transmission Owner system dispatchers shall immediately comply with that order. Quick response voltage reduction shall normally be accomplished within ten (10) minutes of the order.
Zone	A defined portion of the NYCA area that encompasses a set of load and generation buses. Each zone has an associated zonal price that is calculated as a weighted average price based on generator LBMPs and generator bus load distribution factors. A "zone" outside the NY control area is referred to as an external zone. Currently New York State is divided into eleven zones, corresponding to ten major transmission interfaces that can become congested.

ATTACHMENT B

NYSRC RESOLUTION

NEW YORK STATE RELIABILITY COUNCIL, L.L.C.
APPROVAL OF NEW YORK CONTROL AREA
INSTALLED CAPACITY REQUIREMENT FOR THE PERIOD
MAY 1, 2019 THROUGH APRIL 30, 2020

---

1. WHEREAS, reliable electric service is critical to the economic and social welfare of the millions of residents and businesses in the State of New York; and

2. WHEREAS, the reliable and efficient operation of the New York State Power System is fundamental to achieving and maintaining reliability of power supply; and

3. WHEREAS, The New York State Reliability Council, L.L.C.'s (NYSRC) principal mission is to establish Reliability Rules for use by the New York Independent System Operator (NYISO) to maintain the integrity and reliability of the NYS Power System; and

4. WHEREAS, the NYSRC is responsible for determining the New York Control Area (NYCA) annual Installed Capacity Requirement (ICR); and

5. WHEREAS, the NYSRC Technical Study Report: NYCA Installed Capacity Requirement for the Period May 2019 through April 2020, dated December 7, 2018 (Technical Study Report), prepared by the NYSRC Installed Capacity Subcommittee, concludes that, under base case conditions, the required NYCA installed reserve margin (IRM) for the May 1, 2019 through April 30, 2020 Capability Year is 16.8%; and

6. WHEREAS, in light of the Technical Study Report results, the modeling and assumption changes made to simulate actual operating conditions and system performance as set forth in Table 6-1 of the Technical Study Report, the numerous sensitivity studies evaluated as set forth in Table 7-1 of the same report, and other relevant factors;

7. NOW, THEREFORE BE IT RESOLVED, that in consideration of the factors described above, the NYSRC finds that an IRM requirement at 17.0%, which equates to an ICR of 1.17 times the forecasted NYCA 2019 peak load, will satisfy the criteria for resource adequacy set forth in the NYSRC's Reliability Rule A.1; and hereby sets the NYCA IRM requirement for the May 1, 2019 to April 30, 2020 Capability Year at 17.0%.

12-7-2018

CERTIFICATE OF SERVICE

I hereby certify that I have this day served the foregoing document upon each person designated on the official service list in this proceeding in accordance with the requirements of Rule 2010 of the Commission's Rules of Practice and Procedure.

Dated at Washington, D.C. this 21st day of December, 2018.

/s/ Carlos L. Sisco
Carlos L. Sisco
Senior Paralegal
Winston & Strawn LLP
1700 K Street, N.W.
Washington, DC 20006-3817
202-282-5000