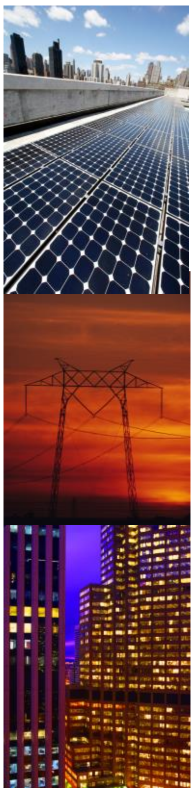
Appendices update October 22, 2017

New York Control Area Installed Capacity Requirement



For the Period May 2017 To April 2018

December 8, 2017

New York State Reliability Council, LLC
Installed Capacity Subcommittee

Table of Contents

Table of Tables & Figures

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 2017 and 2018 IRM reports.

Figure A.1 NYCA ICAP Modeling

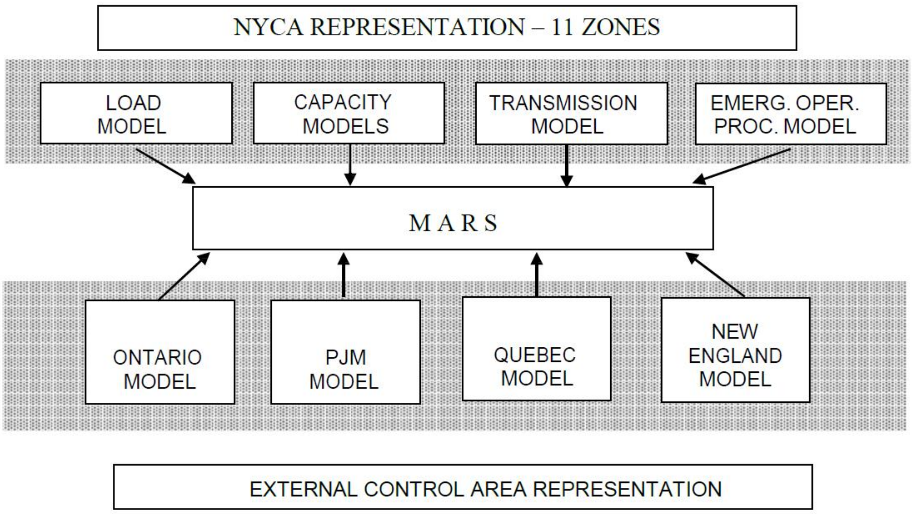


Table A.1 Modeling Details

#	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 2017 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] 2017 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 402 replications to converge to a standard error of 0.05 and required 1942 replications to converge to a standard error of 0.025. For our cases, the model was run to 2000 replications at which point the daily LOLE of 0.100 days/year for NYCA was met with a standard error of 0.024. The confidence interval at this point ranges from 17.8% to 18.4%. It should be recognized that an 18.1% IRM is in full compliance with the NYSRC Resource Adequacy rules and criteria (see Base Case Study Results section).

Commented [A1]: Will need to be updated

A.1.2 Conduct of the GE-MARS analysis

The study was performed using Version 3.21 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 2018 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	2017 Study Assumption	2018 Study Assumption	Explanation
Peak Load	October 1, 2016 forecast NYCA: 33,273 MW NYC: 11,670 MW LI: 5,450 MW GHIJ: 16,073	October 1, 2017 NYCA: 32,853 MW NYC: 11,528 MW LI: 5,446 MW G-J: 15,878 MW	Forecast based on examination of 2016 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	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 2017 to review weather-adjusted peaks for the summer of 2017 prepared by the NYISO and the Transmission Owners. Regional load growth factors (RLGFs) for 2018 were updated by most Transmission Owners; otherwise the same RLGFs that were used for the 2017 ICAP forecast were maintained. The 2018 forecast was produced by applying the RLGFs to each TO's weather-normalized peak for the summer of 2017.

The results of the analysis are shown in Table A-4. The 2017 peak forecast was 33,178 MW. The actual peak of 29,643 MW (col. 2) occurred on July 19, 2017. After accounting for the impacts of weather, the weather-adjusted peak load was determined to be 32,857 MW (col. 6), 321 MW (1.0%) below the forecast. The Regional Load Growth Factors are shown in column 9. The 2018 forecast for the NYCA is 32,868 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 2018 IRM study.

Table A.4 2018 Final NYCA Peak Load Forecast

2018 IRM Coincident Peak Forecast by Transmission District for NYSRC

(1)	(2)	(3)	(4)	(5)	(6)=(2+3+4+5)	(7)	(8)	(9)	(10)=(8)*(9)	(11)	(12)=(10)+(11)
Transmission District	2017 Actual MW	2017 Estimated SCR & Muni Self-Gen	SCR/EDRP Estimate MW	Weather Adjustment MW	2017 Weather Normalized MW	No Loss Reallocation	2017 Weather Normalized MW	Regional Load Growth Factors	2018 ICAP Forecast, Before Adjustments	BTM:NG and Other Adjustments to Load	2018 IRM Final Forecast
Con Edison	11,864	0	0	1,245	13,109		13,109.0	1.0022	13,138		13,138
Cen Hudson	1,000	0	0	96	1,096		1,096.0	0.9820	1,076		1,076
LIPA	4,989	10	0	374	5,373		5,373.0	0.9952	5,347	39	5,386
Nat. Grid	6,202	56	0	749	7,007		7,007.0	1.0030	7,028		7,028
NYPA	322	0	0	4	326		326.0	0.9603	313		313
NYSEG	2,878	0	0	354	3,232		3,232.0	0.9980	3,226		3,226
O&R	975	0	0	152	1,127		1,127.0	1.0017	1,129		1,129
RG&E	1,413	0	0	174	1,587		1,587.0	0.9905	1,572		1,572
Grand Total	29,643	66	0	3,148	32,857	0	32,857	0.9991	32,829	39	32,868
								2018 Forecast from 2017 Gold Book			33,078
								Change from Gold book			-210

2018 IRM Locality Peak Forecast by Transmission District for NYSRC

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)=(8)*(9)	(11)	(12)=(10)+(11)
Locality	2017 Actual MW	2017 Estimated Muni Self-Gen	SCR/EDRP Estimate MW	Weather Adjustment MW	2017 Weather Normalized MW	No Loss Reallocation	2017 Weather Normalized MW	Regional Load Growth Factors	2018 ICAP Forecast, Before Adjustments	BTM:NG and Other Adjustments to Load	2018 IRM Final Forecast
Zone J - NYC	10,668	0	0	848	11,516		11,516	1.0022	11,541	0	11,541
Zone K - LI	5,137	10	0	285	5,432		5,432	0.9952	5,406	39	5,445
Zone GHIJ	14,704	0	0	1,176	15,880		15,880	1.0007	15,890	0	15,890

(2) Zonal Load Forecast Uncertainty

For 2018, new load forecast uncertainty (LFU) models were prepared. LFU models were provided by Con-Ed and LIPA for Zones H&I, J and K. The NYISO developed models for Zones A through G and reviewed the models for the other zones. 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.

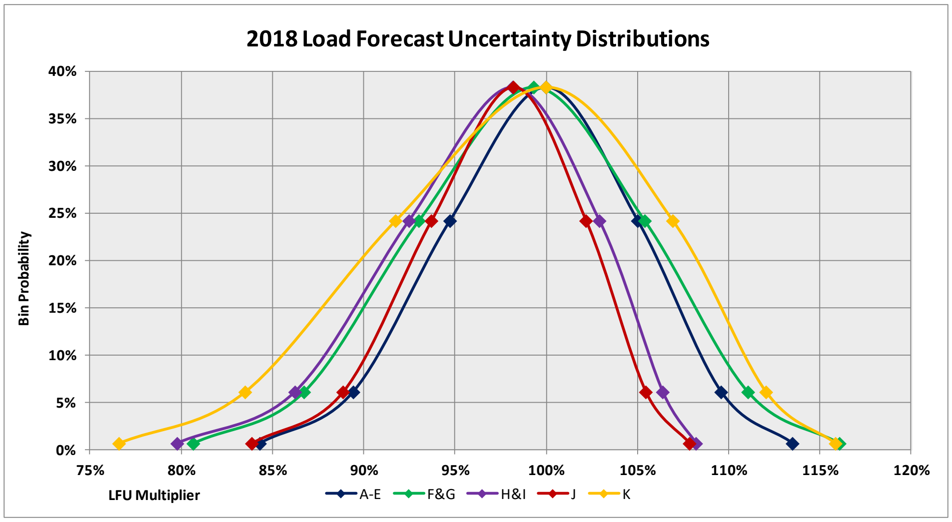
Table A.4 2018 Load Forecast Uncertainty Models

2018 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



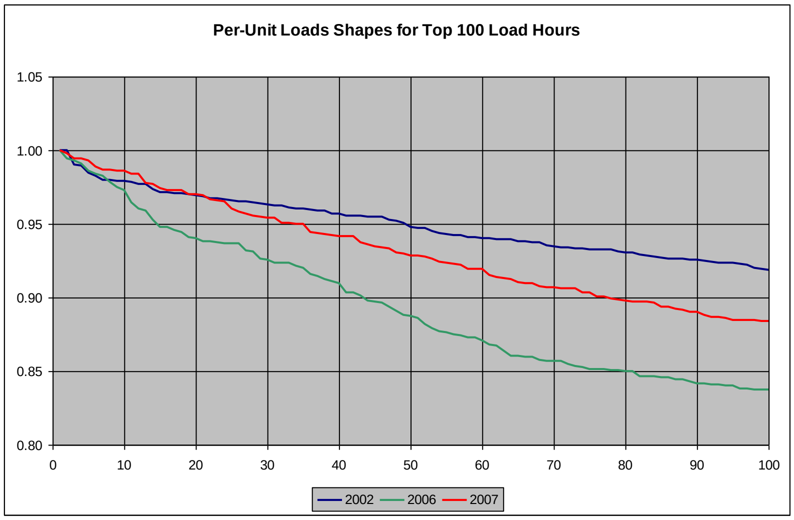
The Consolidated Edison models for Zones H, I & J are based on a peak demand with a 1-in-3 probability of occurrence (67th percentile). All other zones are designed at a 1-in-2 probability of occurrence of the peak demand (50th percentile). The methodology and results for determining the 2018 LFU models 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 as a whole 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.

With GE-MARS version 3.18, the logic to calculate the daily LOLE index was enhanced. Previously, the index was calculated using the base load shape's daily peak hours for all bins. The enhanced version (3.18) calculates the LOLE index using the daily peak hour for each load shape in each bin. This is the GE-MARS default setting.

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 2017 Load and Capacity Data Report is the primary data source for these resources. Table A.5 provides a summary of the capacity resource assumptions in the 2018 IRM study.

Table A.5 Capacity Resources

Parameter	2017 Study Assumption	2018 Study Assumption	Explanation
Generating Unit Capacities	2016 Gold Book values. Use min (DMNC vs. CRIS) capacity value	2017 Gold Book values. Use min (DMNC vs. CRIS) capacity value	2017 Gold Book publication
Planned Generator Units	0 MW of new non- wind resources. 66.9 MW of project related re-ratings	784 MW of new non- wind resources, plus 52 MW of project related re-ratings.	Unit rerate
Wind Resources	221.1 MW of Wind Capacity additions totaling 1676.2 MW of qualifying wind	77.7 MW of Wind Capacity additions totaling 1733.4 MW of qualifying wind	Renewable units based on RPS agreements, interconnection queue, and ICS input.
Wind Shape	Actual hourly plant output over the period 2011-2015. New units will use zonal hourly averages or nearby units.	Actual hourly plant output over the period 2012-2016. New units will use zonal hourly averages or nearby units.	Program randomly selects a wind shape of hourly production over the years 2012-2016 for each model iteration.
Solar Resources (Grid connected)	31.5 MW Solar Capacity. Model chooses from 4 years of production data covering the period 2012-2015.	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 2011-2015. New units will use zonal hourly averages or nearby units.	Actual hourly plant output over the period 2012-2016. New units will use zonal hourly averages or nearby units.	Program randomly selects a solar shape of hourly production over the years 2012-2016 for each model iteration.

Parameter	2017 Study Assumption	2018 Study Assumption	Explanation
BTM- NG Program	N/A	Model these units at their full CRIS adjusted output value Added 47.0 MW generator Added Load (MW TBD during 2018 load forecast) Removed Stony Brook (9.6 MW CRIS) from the generator list value	Both the load and generation of the single resource BTM:NG Resources. One resource is modeled as participating in the BTM:NG program is modeled during the 2018 Capability Year. Former load modifiers to sell capacity into the ICAP market. Subsequently, the Load forecast will be increased (no resources in PBC)
Retirements, Mothballed units, and ICAP ineligible units	260.7MW retirements or mothballs reported or Units in IIFO and IR	136.847.5 MW retirements or mothballs reported or Units in IIFO and IR[2]	2017 Gold Book publication and generator notifications
Forced and Partial Outage Rates	Five-year (2011-2015) GADS data for each unit represented. Those units with less than five years – use representative data. (Attachments C and C1)	Five-year (2012-2016) GADS data for each unit represented. Those units with less than five years – use representative data. (Attachments C and C1)	Transition Rates representing the Equivalent Forced Outage Rates (EFORd) during demand periods over the most recent five-year period (2012-2016)

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

Parameter	2017 Study Assumption	2018 Study Assumption	Explanation
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
Gas Turbine Ambient Derate	Derate based on provided temperature correction curves.	Derate based on provided temperature correction curves.	Operational history indicates derates in line with manufacturer's curves
Small Hydro Resources	Derate by 46%	Actual hourly plant output over the period 2012-2016.	Program randomly selects a Hydro shape of hourly production over the years 2012-2016 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 (2012-2016)

(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.

(2) Wind units are rated at the lower of their CRIS value or their nameplate value in the model. The 2017 NYCA Load and Capacity Report, issued by the NYISO, is the source of those generating units and their ratings included on the capacity model. Planned Generator Units

Two planned new non-wind generating units, having a total capacity of 784 MW, are included in the 2018 IRM Study: Greenidge 4 and Competitive Power Ventures. In addition, an increase of the rating of the existing Bethlehem Energy Center by 52 MW is included. Three existing generators had intended to retire but have rescinded their notice to retire and remain active in the New York markets.

(3) Wind Modeling

Wind generators are modeled as hourly load modifiers. The GE MARS program will randomly select a wind shape from multiple years of production data. The output of each unit varies between 0 MW and the nameplate value based actual hourly plant output over the period 2012-2016 . New units will use zonal hourly averages or nearby units. Characteristics of this data indicate a capacity factor of approximately 14% during the summer peak hours. A total of 1733.4 MW of installed capacity associated with wind generators is included in this study including 78 MW of planned new wind capacity.

Commented [A2]: Update yes or no?

Table A.6 Wind Generation

B3 - Wind Resources				
Wind Resouce	Zone	CRIS (MW)	Summer Capability (MW)	CRIS adusted value from 2017 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
		1658.2	**1661.8**	**1655.7**
New and Proposed IRM Study Wind Units				
Jericho Rise	D	77.7	77.7	77.7
		77.7	**77.7**	**77.7**
Non - ICAP Participating Wind Units				
	Zone	CRIS (MW)	Nameplate Capability (MW)	CRIS adusted value from 2017 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		1735.9	1811.1	**1733.4**

(4) Solar Modeling

Solar generators are modeled as hourly load modifiers. The GE MARS program will randomly select a solar shape from multiple years of production data. The output of each unit varies between 0 MW and the nameplate MW value based on 5 years of production data covering the period 2012-2016. A total of 31.5 MW of solar capacity was modeled in Zone K.

(5) Retirements

Three units in Zone K totaling 137 MW were slated to retire before the summer of 2018. All three units have rescinded their notice of retirement and are expected to remain fully operational through the 2018 capability year. .

(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 2018 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 2012 through 2016. 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. Where the NYISO had suspect data for a unit that could not be resolved prior to this study, NERC class average data was substituted for the year(s) of suspect data.

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

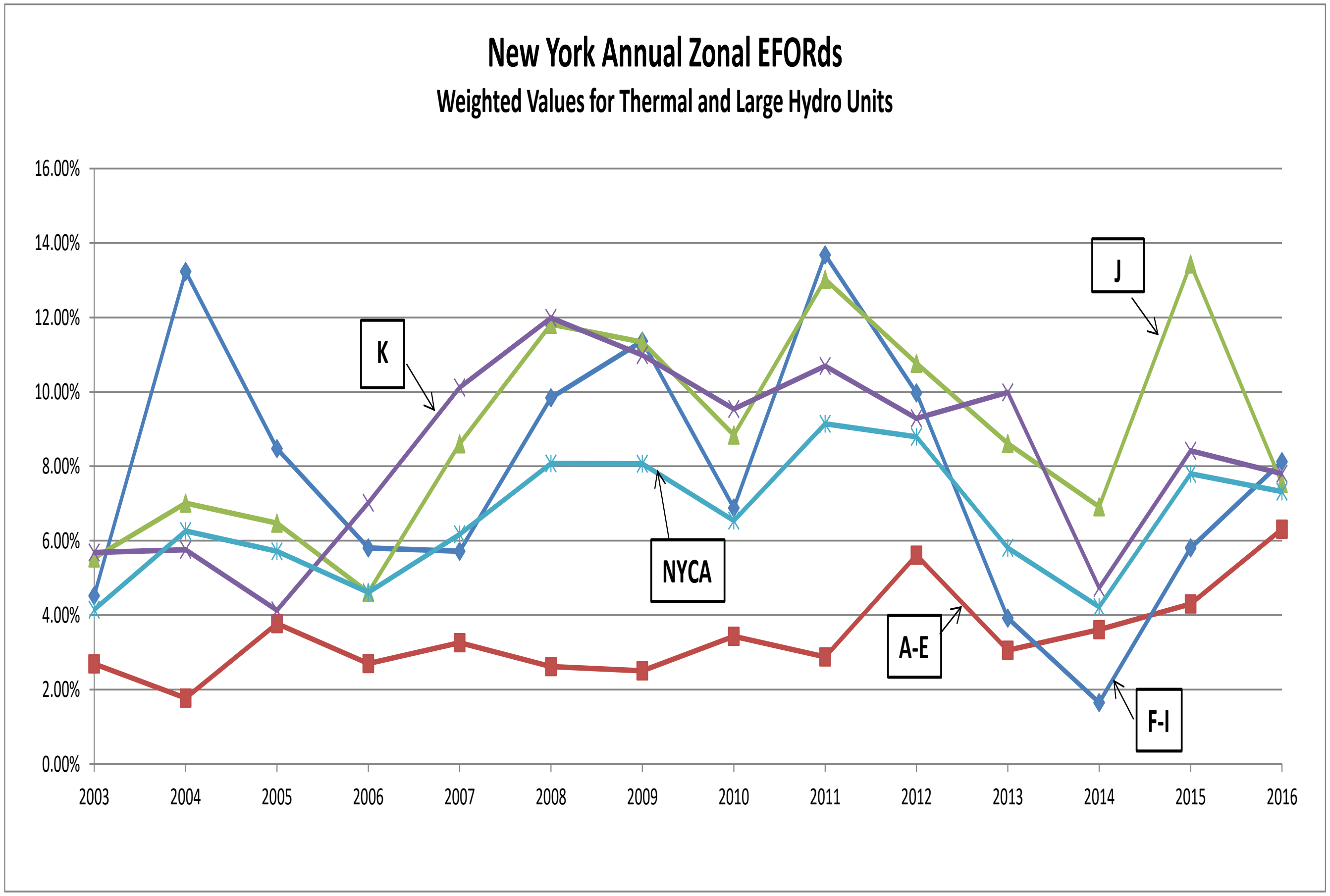


Figure A.5 Five-Year Zonal EFORds

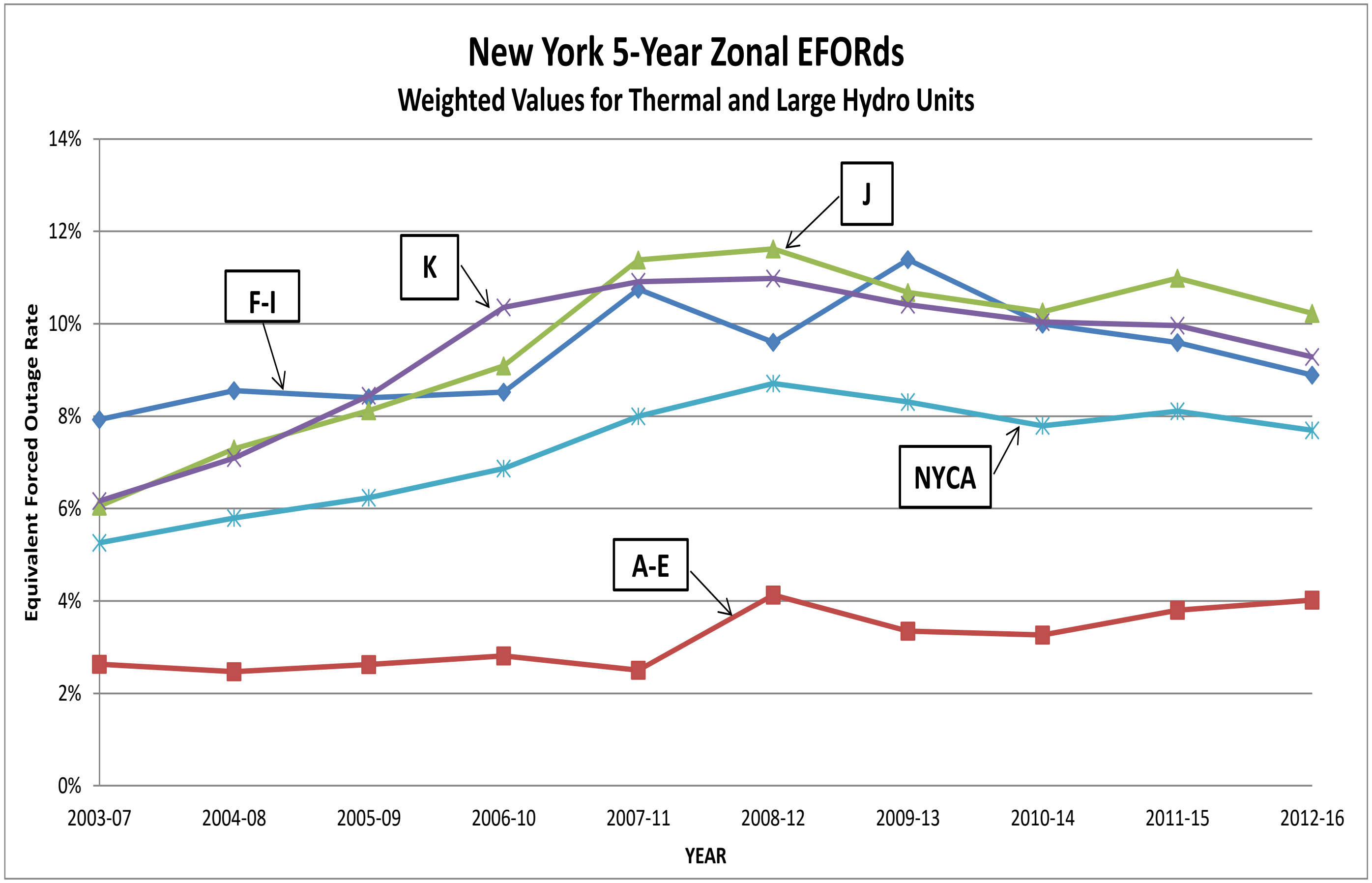


Figure A.6 NYCA Annual Availability by Fuel

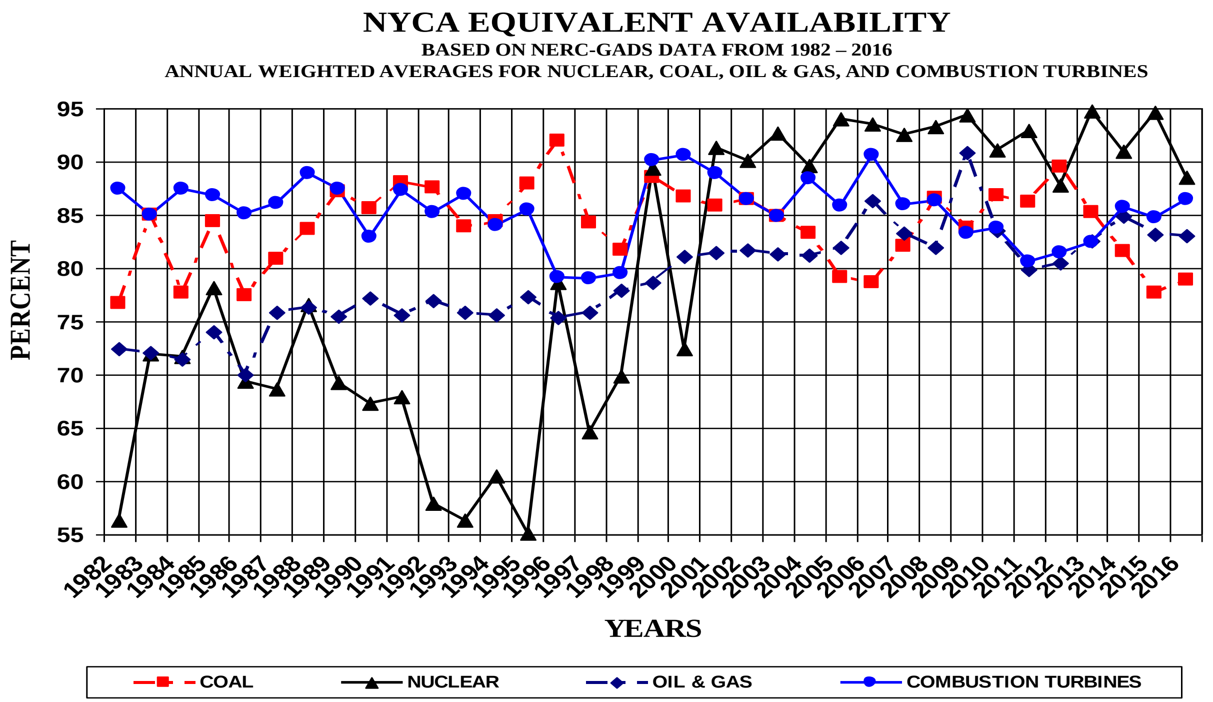


Figure A.7 NYCA Five-Year Availability by Fuel

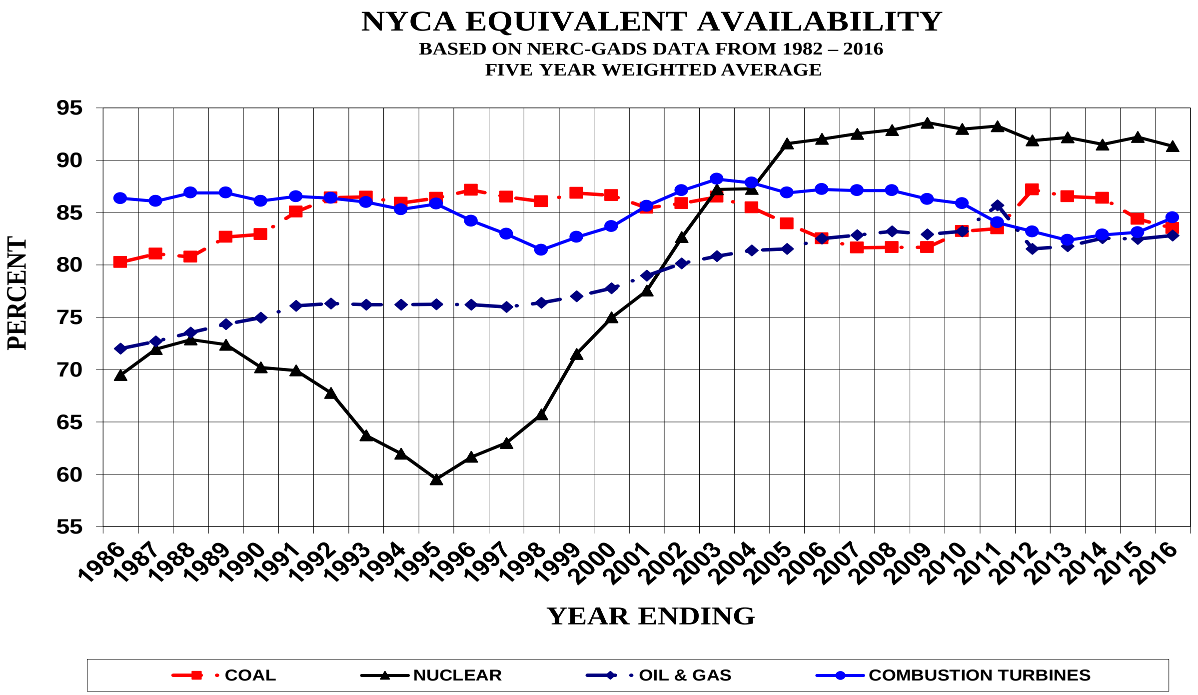


Figure A.8 NERC Annual Availability by Fuel

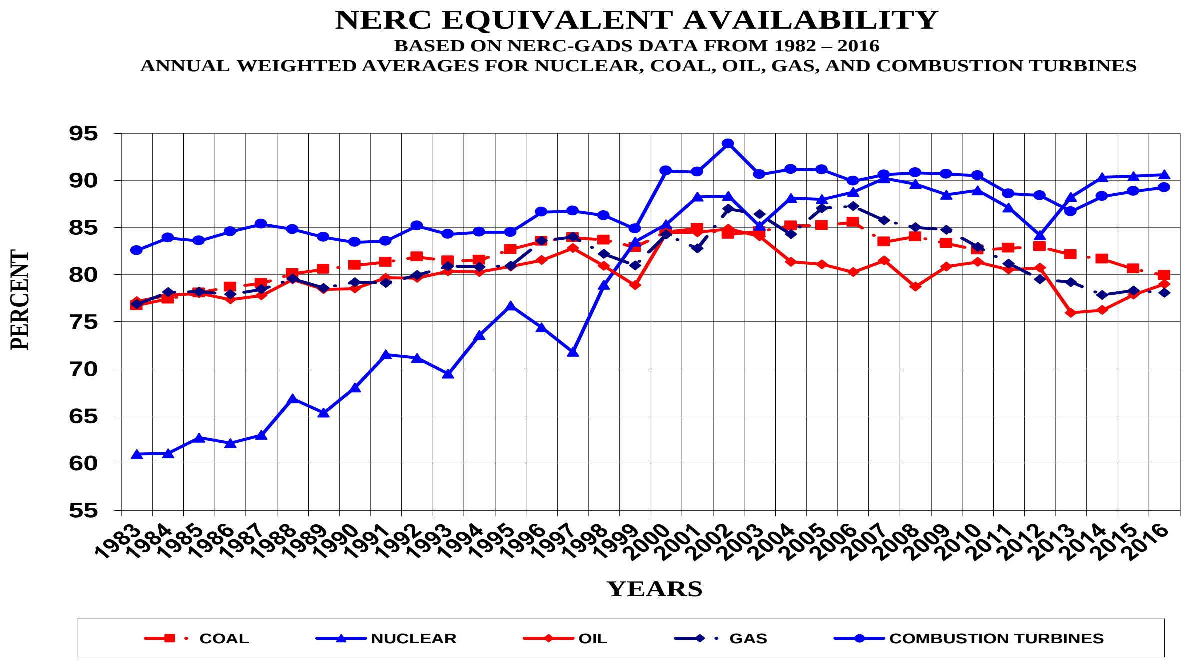
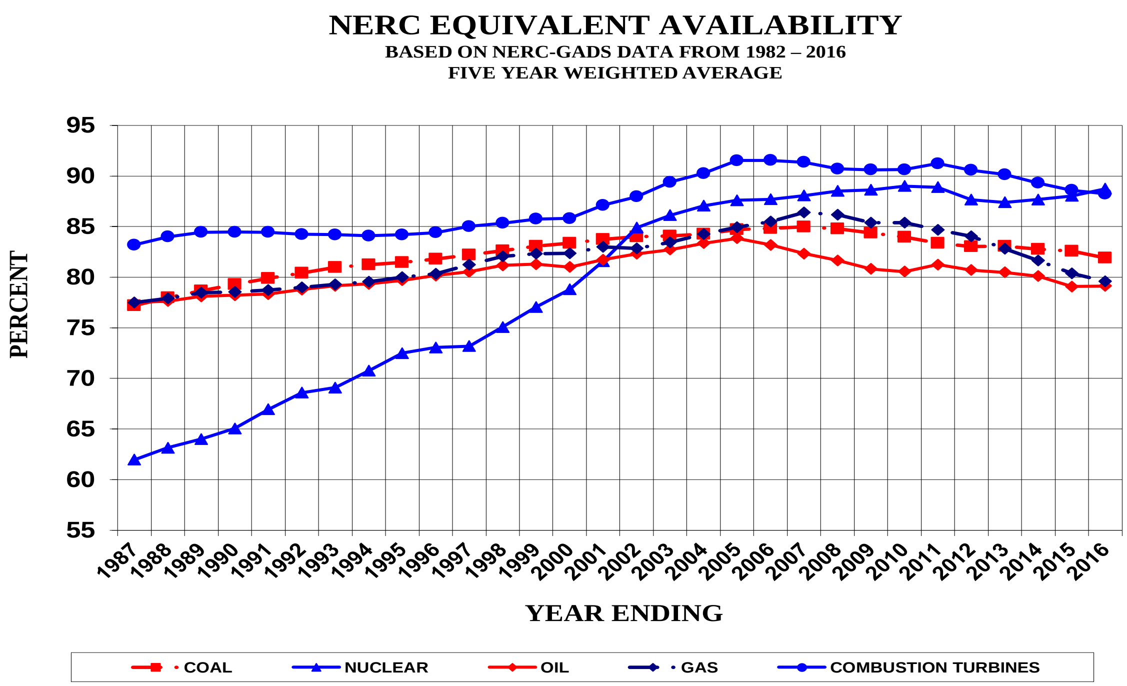


Figure A.9 NERC Five-Year Availability by Fuel



(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 1992 through 2016 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 2018 IRM Study, a nominal 50 MW of summer maintenance is modeled. The amount is equally divided between Zone J and Zone K. Figure A.11 shows the weekly scheduled maintenance for the 2016 IRM Study compared to this study.

(8) Gas Turbine Ambient Derate

Operation of combustion turbine units at temperatures above DMNC test temperature results in reduction in output. These reductions in *g*as turbine and combined cycle capacity output are captured in the GE-MARS model using deratings 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.

The derate does not affect all units because there are units capable of generating up to 88 or 94 MW but are limited by permit to 79.9 MW, so these units are not impacted by the temperature derating in obtaining an output of 79.9 MW. The accuracy of temperature corrections for all combustion turbines will continue to be evaluated as operational data becomes available.

(9) Large Hydro Derates

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

Commented [A3]: Not available in assumption matrix. Needs to be updated through 2016

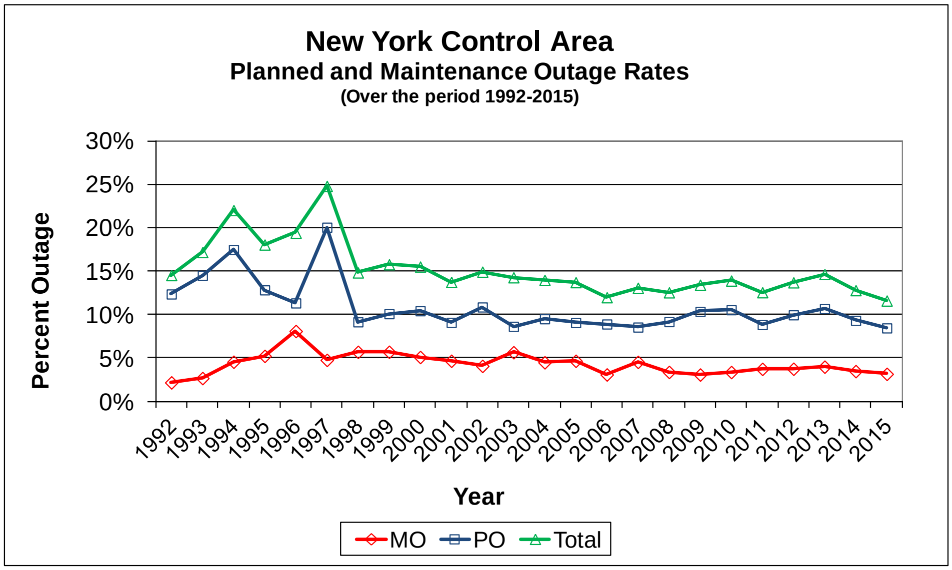
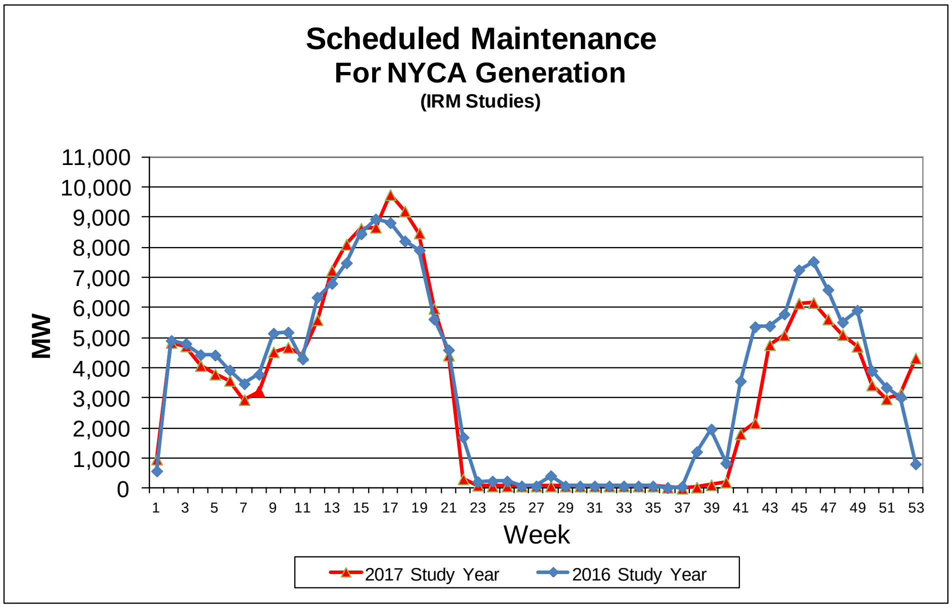


Figure A.11 Scheduled Maintenance

Commented [A4]: Not available in assumption matrix. Needs to be updated



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 2018 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. The transfer limits are further refined by assessments conducted for this IRM study. The assumptions for the transmission model included in the 2018 IRM Study are listed in Table A.7.

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.

The interface transfer limits were updated for the 2018 IRM Study model based on transfer limit analysis performed for the 2016 Reliability Needs Assessment.

Table A.7 Transmission System Model

Parameter	2017 Model Assumptions	2018 Model Assumptions Recommended	Basis for Recommendation
Interface Limits	All changes reviewed and commented on by TPAS	All changes reviewed and commented on by TPAS	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

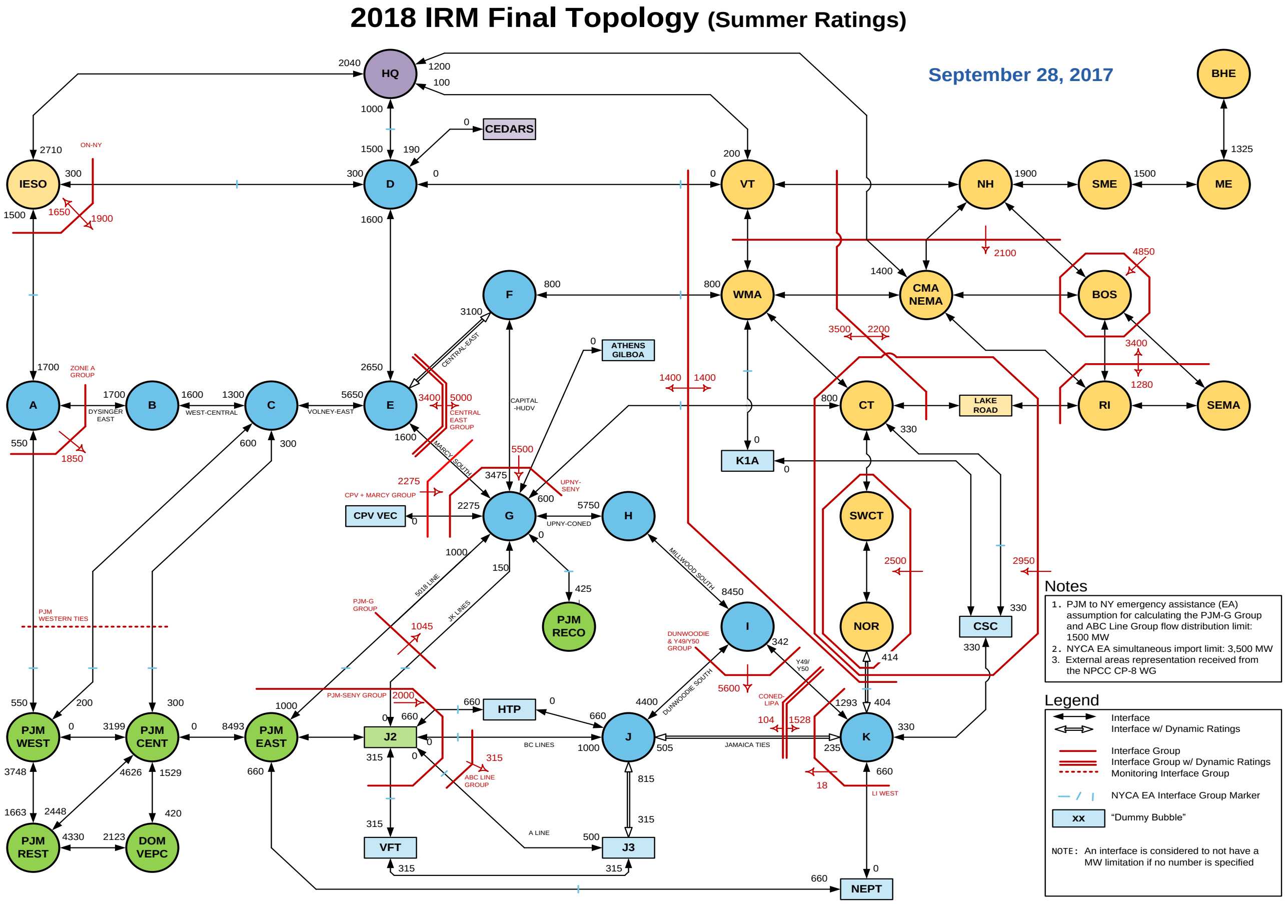


Figure A.13 Dynamic Interface Ratings Information

2018 MARS Topology - Dynamic Limits and Grouping Information

September 28, 2017

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 Available	E_to_F		E_to_FG	
	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

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%	14%

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

Table A.8 Interface Limits Updates

	2017		2018		Delta	
Interface	**Forward**	**Reverse**	**Forward**	**Reverse**	**Forward**	**Reverse**
UPNY-Con Ed	5600		5750		+150	
I to J & K	5400		5600		+200	
LI Sum	1528	120/91/0	1528	104/74/0		-16/-17/0
LI West	99999	34		18		-16
Figure A.12 above shows details surrounding changes related to the RECO agreement as well as the A, B, C, J, K, and 5018 lines.						

The topology for the 2018 IRM Study features several changes from the topology used in the 2017 IRM Study. These changes fit into the following three categories:

1. Changes to support the CPV Valley Energy Center("VEC")

A number of changes were made to the MARS topology to incorporate the CPV VEC project for the 2018 IRM Study. An interface to connect the CPV VEC area to the Zone G area (CPV_TO_G) was modeled, and a new interface group (Marcy/CPV Group) comprised of CPV_TO_G and the Marcy South interface was added.

The UPNY-Con Ed and the I to J & K interface limits increased from the 2017 IRM to the 2018 IRM limits: The UPNY-Con Ed interface limit was increased by 150 MW and the I to J & K interface limit was increased by 200 MW. The primary reasons for the increase were the addition of the CPV VEC plant and a reduction in load growth in Zones G through I.

2. Changes to support the NYISO-PJM Joint Operating Agreement (e.g. A, B, C, J and K PARs, RECO delivery)

Several changes to the topology were made based on the final JOA amendment between the NYISO and the PJM Interconnections. Structurally these changes included (i) the relocation of PJM_RECO, (ii) the separation of AREA_J2 from PJM_EAST, (iii) the separation of the VFT from AREA_J3, and (iv) the separation of the A and B/C Lines. This agreement formalized flow percentages for transactions between the two markets and these percentages were applied to a base emergency assistance value of 1,500 MW to arrive at interface group limits of 315 and 705 MW respectively for the ABC and PJM-G groups. The latter group limit includes an additional 340 MW allocation (for a total limit of 1,045 MW) to reflect the RECO flow delivery of 425 MW, of which 80% is delivered over the PJM_5018 interface. The RECO delivery is modeled as a firm contract that allocates flow on the PJM Western ties (20%), on the NY upstate ties (prorated 20%), and the 5018 Line (80%). The topology was changed for the 2018 IRM Study to allow the flow from

PJM to NY to align with the distributions described in the JOA, as shown in the table below.

Table A.9 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%	14%

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

PSEG-LIPA provided updates to certain interface limits around Long Island, mainly because of changes to the load. The J to K, LI Sum, and LI West in the reverse direction (flow out of Long Island) were reduced slightly compared to the 2017 IRM Study.

A summary of the above described changes can be found on table A.10 below.

Table A.10 Summary of major changes from 2017 to 2018 IRM topology:

Areas of Focus	Topology Proposal
Modeling of CPV Valley	Similar to 2016 RNA: • CPV MW in a new dummy bubble • 0.3 factor - Impact on UPNY-SENY flow: simulates a 30% of CPV Valley reduction on UPNY-SENY capacity • 0.9 factor - impact on Marcy South flow: simulates a 90% of CPV Valley flow reduction on Marcy South capacity

Modeling of RECO Deliveries	• Explicit Modeling of 5018 Line
	• Constant RECO load of 425 MW
	• Firm contract from PJM_EAST
	  ○ 80% of EA Limit on 5018 Line = 320 MW
	  ○ 20% of EA Limit on Western Ties = 85 MW

Modeling of A/B/C & J/K Lines	• Reinstate J2 dummy bubble • Redefine VFT & HTP interfaces • Restore Line Ratings

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 value of this limit is based on a recommendation from the ICS 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 5-10 is as follows:

Table A.9 External Area Representations

Parameter	2017 Study Assumption	2018 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 284.9 MW	Long term firm sales of 283.8 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 among all	All NPCC Control Areas have indicated that they will share reserves equally among all	Per NPCC CP-8 working group assumption

Table A.10, below, shows the final reserve margins and LOLEs for the Control Areas external to NYCA.

Table A.10 Outside World Reserve Margins

Commented [A5]: Not available in assumption matrix. Needs updating

Area	2016 Study Reserve Margin	2017 Study Reserve Margin	2016 Study LOLE (Days/Year)	2017 Study LOLE (Days/Year)
Quebec	38.6%*	38.5%*	0.104	0.113
Ontario	34.2%**	21.8%**	0.112	0.110
PJM	11.9%	15.2%	0.147	0.141
New England	15.5%	15.0%	0.136	0.134

*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.12 were provided by the NYISO based on operator experience. Table A.11 lists the assumptions modeled.

The values in Table A.11 are based on a NYISO forecast that incorporates 2017 (summer) operating results. This forecast is applied against a 2018 peak load forecast of 32,853 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.11 Assumptions for Emergency Operating Procedures

Parameter	2017 Study Assumption	2018 Study Assumption	Explanation
Special Case Resources	July 2016 –1192 MW based on registrations and modeled as 841 MW of effective capacity. Monthly variation based on historical experience (no Limit on number of calls) *	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) *	MW registered in the program, discounted to historic availability.
EDRP Resources	July 2016 75 MW registered modeled as 13 MW in July and proportional to monthly peak load in other months. Limit to five calls per month	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	Those registered for the program, discounted to historic availability. Summer values calculated from July 2017 registrations.
EOP Procedures	665 MW of non-SCR/non-EDRP resources	609.6 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.12 Emergency Operating Procedures Values

Parameter	Procedure	Effect	MW Value
1	Special Case Resources (SCRs)	Load relief	1,219 MW Enrolled/ 868 MW modeled
2	Emergency Demand Response Programs (EDRPs).	Load relief	16 MW Enrolled/3 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	341 MW
6	Voluntary industrial curtailment***	Load relief	121.8 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 1219 MW.*
*** The EDRPs are modeled as 16 MW discounted to 3 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 2018 peak load of 32,583 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 sufficient 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.R2 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.13 SCR Performance

Zones	Forecast SCRs (MW)	Overall Performance (%)
A - F	538.1	77.3%
G - I	52.8	63.8%
J	247.6	63.1%
K	29.1	60.5%
NYCA	867.6	71.2%

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 EDRPs 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 value is 1219 MW. This value is the result of applying historic growth rates to the latest participation numbers.

EDRPs are modeled as a 3 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 16 MW based on actual experience.

A.4 MARS Data Scrub

A.4.1 GE Data Scrub

Commented [A6]: Needs updating

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 correct as is, or institutes a correction. The results of this data scrub are shown in Table A.14 for the preliminary base case.

Table A.14 GE MARS Data Scrub

Item	Description	Disposition	Data Change	Post PBC* Affect
1	**Generation:** 21 Units have EFORd changes greater than 50% versus 24 Units last year.	Data was examined and determined valid. This grouping of units had the lowest average MW output (averaged 15 MW).	No	N/A
2	**Generation:** 62 Units have EFORds between 30% and 50% versus 65 Units last year.	Data was examined and determined valid. These units had low average MW output.	No	N/A

Item	Description	Disposition	Data Change	Post PBC* Affect
3	**Generation:** 15 smaller units had EFORd of zero (same number as last year).	Data was examined and determined valid. This statistic will be continued to be tracked.	No	N/A
4	**Generation:** A zonal comparison of EFORds showed two zones with lower EFORds and six zones showing higher values. The remaining three zones were unchanged.	Values are confirmed with the market values shown in Attachment C of the assumptions matrix.	No	N/A
5	**Generation:** Zonal MWs fell moderately in zone A, while moderate increases were seen in zones C, E, and F	All units changes were identified with DNMC test values.	No	N/A

A.4.2 NYISO Data Scrub

Commented [A7]: Needs Updating

The NYISO also performs a review of the MARS data independently from GE. Table A.15 shows the results of this review for the preliminary base case.

Table A.15 NYISO MARS Data Scrub

Item	Description	Disposition	Data Change	Post PBC* Affect
1	**MARS version 3.20**: Error in functionality of the new feature to remove load shapes and EOP inputs for dummy bubbles, which caused units in dummy bubbles incorrectly scheduled for maintenance during the period of summer peak load.	In the parametric study cases before the preliminary base case, a special table MNT-FIXC has been used to force no NYCA units other than that in the Assumption Matrix to be scheduled for maintenance during the period of summer peak load.	Yes	No
2	**Generation:** Unit KNDBLK was incorrectly entered into another zone.	Corrected in the parametric study cases before the preliminary base case.	Yes	No
3	**Generation:** The CRIS values used for MARS model for a few small units were slightly different from the Gold Book.	Corrected in the parametric study cases before the preliminary base case.	Yes	No
4	**Load**: The first day of load shapes was out of phase.	Corrected in the parametric study cases before the preliminary base case.	Yes	No

Item	Description	Disposition	Data Change	Post PBC* Affect
5	**Transition Rate:** Invalid transition rate matrix of the NUSCO cable due to all zero values for state 3.	Corrected in the parametric study cases before the preliminary base case.	Yes	No
6	**Topology:** The transfer limits of a few interfaces associated with cancelling PJM/ConEd wheel were different from the NYCA topology diagram.	Corrected in the parametric study cases before the preliminary base case.	Yes	No
7	**Topology:** Redundant condition set number for the 4th set in the dynamic transfer limit table INF-DYLM.	Corrected in the parametric study cases before the preliminary base case.	Yes	No
8	**Load:** Load shapes start date were out of phase.	Day of week corrected before the preliminary base case.	Yes	No
9	**Generation:** Sithe and Bowline uprates were not in the preliminary base case.	Incorporated into final base case.	Yes	+0.1
10	Switch on PJM interface tie changed to "yes."	Incorporated into final base case.	Yes	No

A.4.3 Transmission Owner Data Scrub

Commented [A8]: Needs updating.

In addition to the above reviews, two transmission owners scrub the data and assumptions from a masked database provided. Table A.16 shows these results. These findings are based on a review of the preliminary base case not the final base case.

Table A.16 Transmission Owner Data Scrub

Item	Description	Disposition	Data Change	Post PBC* Affect
1	Model shows 1850 MW export limit from Zone A while topology map shows 1800 MW	Map was not updated to reflect current topology. Model is correct.	No	N/A
2	NE topology shows values differently in model versus latest published map.	Map was not updated to reflect current topology. Model is correct.	No	N/A

Appendix B

Details of Study Results

B. Details for Study Results

B.1 Sensitivity Results

Table B.1 summarizes the 2018 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 18.7% IRM results then add or remove capacity from all zones in NYCA until the NYCA LOLE approached criteria. The values in Table B.1 are the sensitivity results adjusted to the 18.2% final base.

Table B.1 Sensitivity Case Results

.Case	Description	IRM (%)	NYC (%)	LI (%)
0	**Final Base Case**	18.2	80.7	103.2
	This is the Base Case technical results derived from knee of the IRM-LCR curve. All other sensitivity cases are performed off of this run			
1	**NYCA Isolated**	25.6	85.9	109.9
	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)**	16.2	NA	NA
	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**	11.0	75.6	96.7
	This scenario represents “perfect vision” for 2017 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**	14.5	80.7	103.2
	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.			

.Case	Description	IRM (%)	NYC (%)	LI (%)
5	**No SCRs & no EDRPs**	15.3	77.9	103.0
	Shows the impact of SCRs and EDRPs on IRM.			
6	**Remove CPV Valley Energy Center**	18.5	81.3	103.7
	A full tan 45 curve case based on removing the addition of CPV-VEC (678 MW) from the base case.			
7	**Limit Emergency Assistance from PJM to all of NYCA to 1500 MW**	18.2	80.7	103.2
	This case uses a grouped interface of all PJM to NYCA import ties and restricts the grouping to a limit of 1500 MW			
8	**Model 2,000 MW of additional Wind resources** (adjusted back to 0.100 LOLE by using zones A-F only).	22.7	80.7	103.2
	Add hypothetical Wind capacity to the existing fleet of wind generation to the order of 2,000 MW. This would increase the NYCA participating wind fleet to 3,733 MW.			
9	**Model 2,000 MW of additional bulk Solar resources**	22.8	79.7	105.6
	Add hypothetical Solar capacity to the existing fleet of bulk Solar generations to the order of 2,000 MW. This would increase the NYCA participating bulk Solar fleet to 2,032 MW.			
10	**Model 2,000 MW of Wind and 2,000 MW of Solar additions (4,000 MW total). <u>Perform tan 45.</u>**	26.3	80.8	105.6
	Add hypothetical resources totaling 4,000 MW from the above cases 9 and 10. Perform a tan 45 curve and analysis.			
11	**Model 2,000 MW of Wind and 2,000 MW of Solar additions (4,000 MW total).**	28.2	79.3	105.0
	Add hypothetical resources totaling 4,000 MW from the above cases 9 and 10. Perform this case using the standard sensitivity methodology.			
12	**Remove the 3500 MW EA Limit into NYCA**	18.0	80.5	103.0
	Remove the 3500 MW Emergency Assistance grouped limit entering NYCA from its neighbors. UDRs remain in New York.			
13	**Model a 500 MW Locality export to New England**	N/A	N/A	N/A
	Given time, model a capacity sale of 500 MW from zone G to NY's Western Mass and Connecticut zones.			
14	**Retire the Selkirk Units**	18.3	80.7	103.2

.Case	Description	IRM (%)	NYC (%)	LI (%)
	Retire the two Selkirk units and return to a 0.100 LOLE by adjusting capacity in zones A-F.			
15	**Retire the Binghamton BOP Unit**	18.2	80.7	103.2
	Retire the Binghamton BOP unit and return to a 0.100 LOLE by adjusting capacity in zones A-F.			

B.2 Impacts of Environmental Regulations

B.2.1 Regulations Reviewed for Impacts on NYCA Generators

The NYISO monitors numerous environmental regulatory programs that could impact the operation of NYS Bulk Power System facilities. These state and federal regulatory programs include:

NO_X RACT: Reasonably Available Control Technology (Effective July 2014).

BART: Best Available Retrofit Technology for regional haze (Effective January 2014).

MATS: Mercury and Air Toxics Standard for hazardous air pollutants (Effective April 2015).

MRP: Mercury Reduction Program for Coal-Fired Electric Utility Steam Generating Units – Phase II reduces Mercury emissions from coal fired power plants in New York (Effective January 2015).

CSAPR: Cross-State Air Pollution Rule for the reduction of SO_2 and NO_X emissions in 27 Eastern States. Additional Phase 2 ozone season NO_X emissions reductions promulgated in the CSAPR Update Rule became effective in May 2017.

RGGI: Regional Greenhouse Gas Initiative Phase II cap reductions started January 2014. The program design is undergoing review by the RGGI states in 2016 for design changes to take effect post-2020.

New Source CO_2 Emission Standards: Federal New Source Performance Standards would have become effective October 2015, however, these standards are under judicial review by the courts and administrative review by the Trump administration.

Existing Source CO_2 Emission Standards: Federal emissions limits for existing units under the Clean Power Plan (CPP) would begin in 2022. However, the Supreme Court of the United States stayed the effectiveness of the CPP. EPA has proposed to repeal of the CPP and has solicited for comments on a replacement.

RICE: NSPS and NESHAP/MACT – New Source Performance Standards and Maximum Achievable Control Technology for Reciprocating Internal Combustion Engines (Effective July 2016, however, the exemption for use of non-compliant engines in energy markets has been removed from the regulatory text to address judicial remand).

BTA**:** Best Technology Available for cooling water intake structures (Effective upon SPDES Permit Renewal).

NYC Residual Oil Elimination**:** Phase out of residual oil usage in New York City (NYC) utility boilers post-2020.

DG (Distributed Generation) Rule: New York State Department of Environmental Conservation (NYSDEC) published a final rule on November 1, 2016 affecting small generators. On March 1, 2017, the NYSDEC's final rule was challenged in the Supreme Court of the County of Albany. As part of that litigation, the parties have agreed to stay the implementation and enforcement of 6 NYCRR Part 222, pending the Court's decision on Petitioners-Plaintiffs' request for a preliminary injunction.

The NYISO has determined that as much as 28,000 MW in the modeled fleet will have some level of exposure to environmental regulations. However, the NYISO does not have any information that would indicate that these initiatives may result in NYCA capacity reductions or retirements that would increase LOLE or IRM requirements during the 2018 Capability Year. For additional detail please refer to the 2016 Reliability Needs Assessment (RNA) Report.[3]

[3] NYISO's "2016 Reliability Needs Assessment" report, dated 10/18/2016, at: http://www.nyiso.com/public/webdocs/markets_operations/services/planning/Planning_Studies/Reliability_Planning_Studies/Reliability_Assessment_Documents/2016RNA_Final_Oct18_2016.pdf

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 4.2 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

Commented [A9]: Needs updating

Step	EOP	Expected Implementation (Days/Year)
1	Require SCRs	7.2
2	Require EDRPs	5.6
3	5% manual voltage reduction	5.4
4	30 minute reserve to zero	5.3
5	5% remote controlled voltage reduction	5.2
6	Voluntary load curtailment	3.6
7	Public appeals	2.9
8	Emergency purchases	2.8
9	10 minute reserve to zero	2.6
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

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.

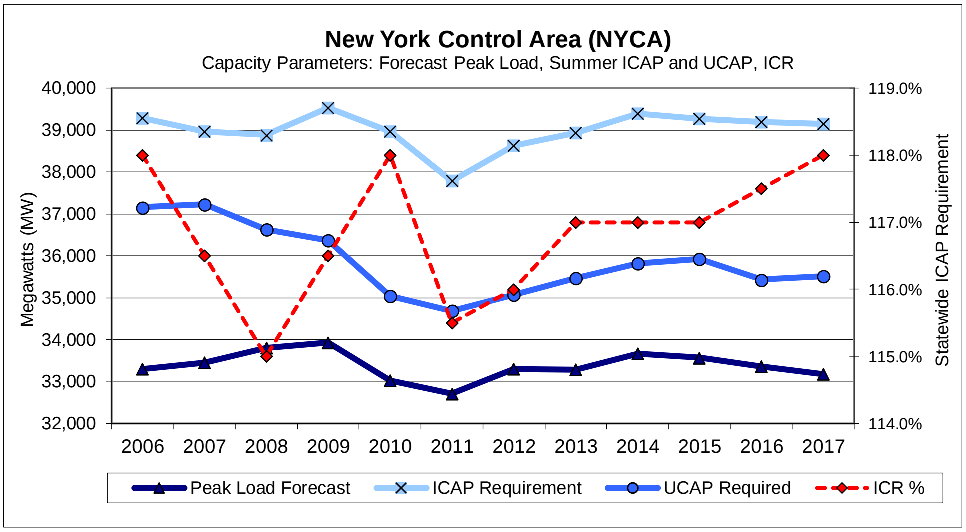
Locational ICAP/UCAP calculations are produced for NYC, LI, G-J and the entire NYCA. Exhibits C.1.1 through C.1.4 summarizes the translation of ICAP requirements to UCAP requirements for these areas. The charts and tables included in these exhibits utilize data from the 2006 through 2017 summer capability periods.

This data reflects the interaction and relationships between the capacity parameters used this study, including Forecast Peak Load, ICAP Requirements, Derating 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

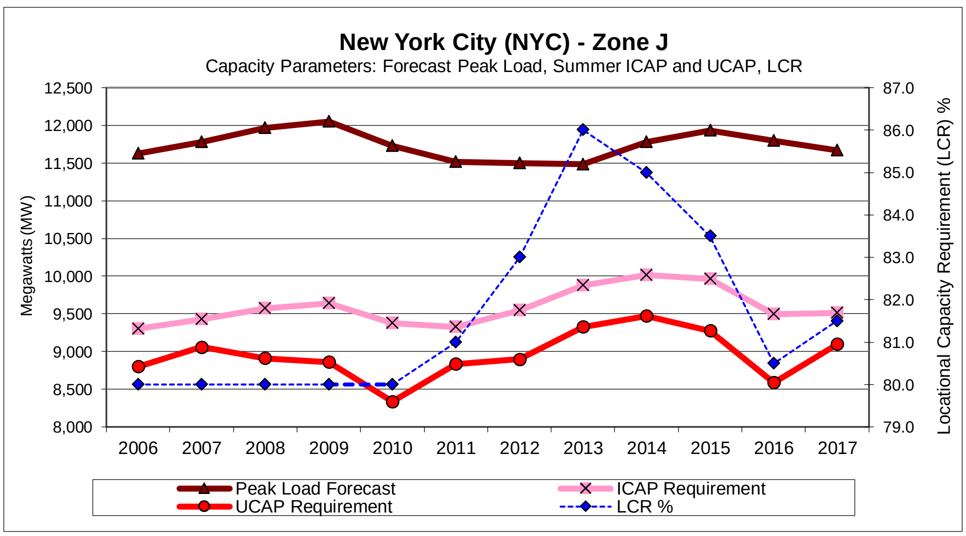
Year	Forecast Peak Load (MW)	Installed Capacity Requirement (%)	Derate Factor	ICAP Requirement (MW)	UCAP Requirement (MW)	Effective UCAP (%)
2006	33,295	118.0	0.0543	39,288	37,154	111.6
2007	33,447	116.5	0.0446	38,966	37,228	111.3
2008	33,809	115.0	0.0578	38,880	36,633	108.4
2009	33,930	116.5	0.0801	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



C.1.2 New York City ICAP to UCAP Translation

Table C.3 New York City ICAP to UCAP Translation

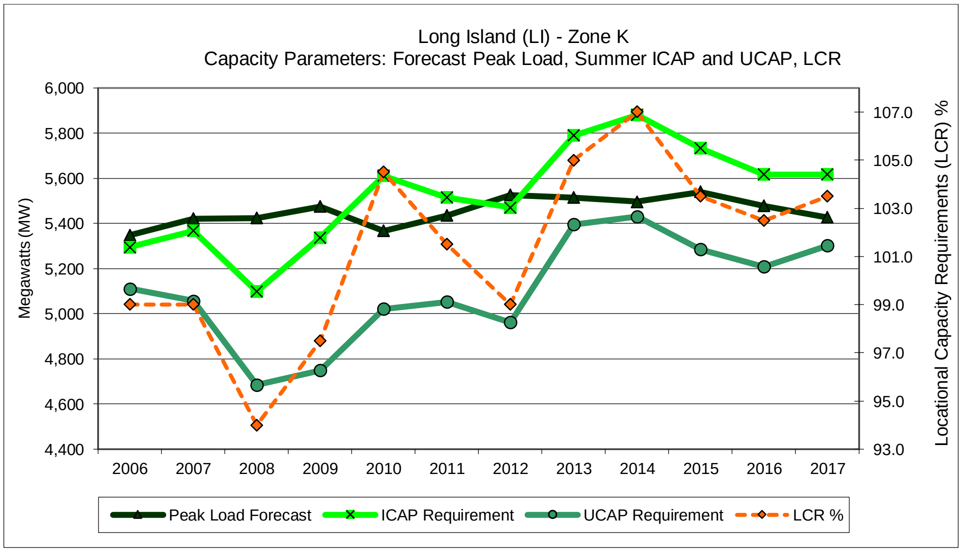
Year	Forecast Peak Load (MW)	Locational Capacity Requirement (%)	Derate Factor	ICAP Requirement (MW)	UCAP Requirement (MW)	Effective UCAP (%)
2006	11,628	80.0	0.0542	9,302	8,798	75.7
2007	11,780	80.0	0.0388	9,424	9,058	76.9
2008	11,964	80.0	0.0690	9,571	8,911	74.5
2009	12,050	80.0	0.0814	9,640	8,855	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



C.1.3 Long Island ICAP to UCAP Translation

Table C.4 Long Island ICAP to UCAP Translation

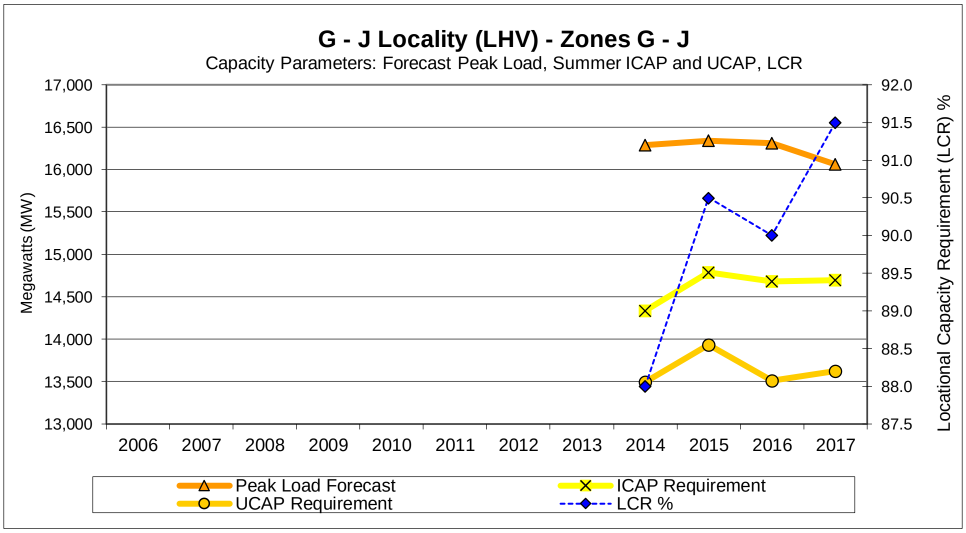
Year	Forecast Peak Load (MW)	Locational Capacity Requirement (%)	Derate Factor	ICAP Requirement (MW)	UCAP Requirement (MW)	Effective UCAP (%)
2006	5,348	99.0	0.0348	5,295	5,110	95.6
2007	5,422	99.0	0.0580	5,368	5,056	93.3
2008	5,424	94.0	0.0811	5,098	4,685	86.4
2009	5,474	97.5	0.1103	5,337	4,748	86.7
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



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

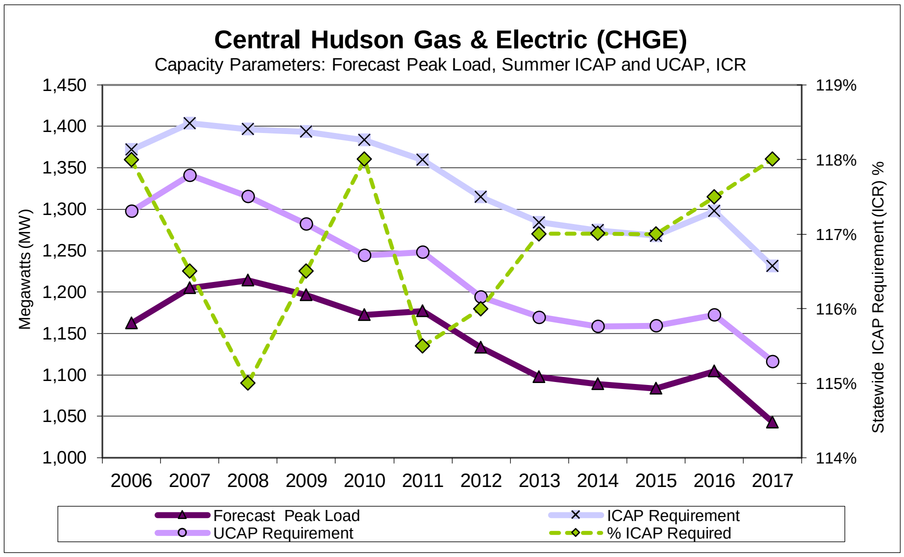


C.2 Transmission Districts ICAP to UCAP Translation

C.2.1 Central Hudson Gas & Electric

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

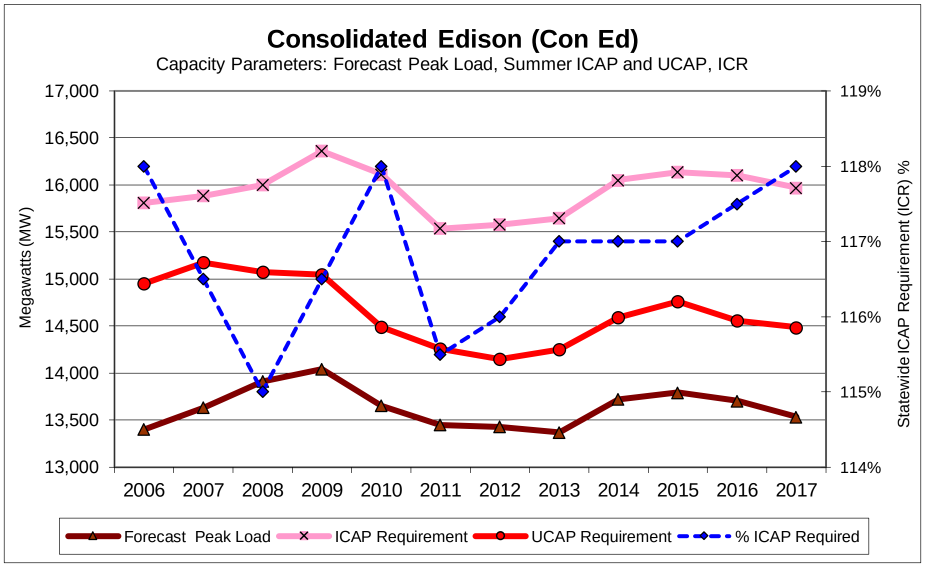
Year	Forecast Peak Load (MW)	ICAP Requirement (MW)	UCAP Requirement (MW)	%ICAP of Forecast Peak	%UCAP of Forecast Peak
2006	1,163	1,372	1,297	118.0%	111.6%
2007	1,205	1,404	1,341	116.5%	111.3%
2008	1,214	1,396	1,316	115.0%	108.4%
2009	1,196	1,394	1,282	116.5%	107.2%
2010	1,172	1,383	1,244	118.0%	106.1%
2011	1,177	1,359	1,248	115.5%	106.0%
2012	1,133	1,315	1,194	116.0%	105.3%
2013	1,098	1,284	1,170	117.0%	106.6%
2014	1,089	1,274	1,159	117.0%	106.4%
2015	1,084	1,268	1,160	117.0%	107.0%
2016	1,104	1,297	1,173	117.5%	106.2%
2017	1,043	1,231	1,117	118.0%	107.0%



C.2.2 Consolidated Edison (Con Ed)

Table C.7 Con Ed ICAP to UCAP Translation

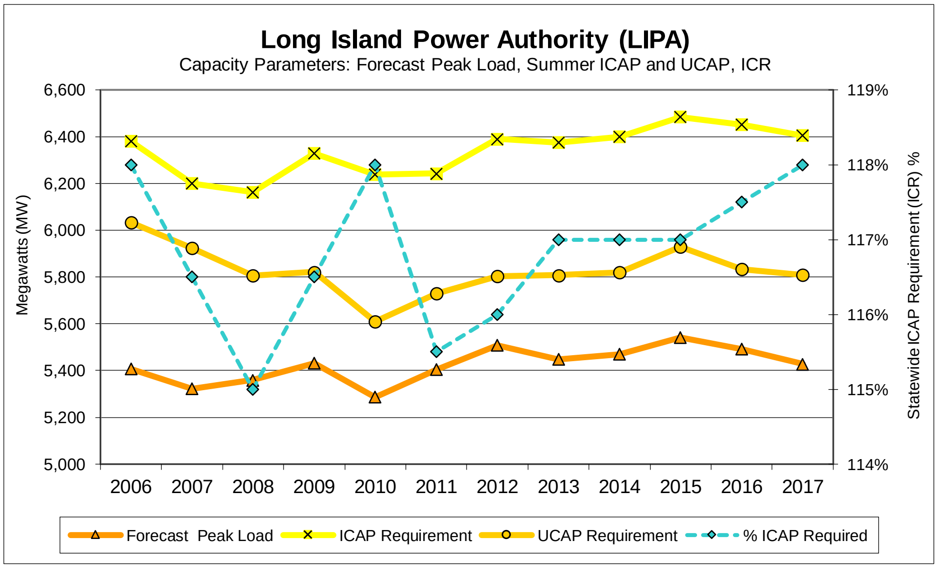
Year	Forecast Peak Load (MW)	ICAP Requirement (MW)	UCAP Requirement (MW)	%ICAP of Forecast Peak	%UCAP of Forecast Peak
2006	13,400	15,812	14,953	118.0%	111.6%
2007	13,634	15,883	15,175	116.5%	111.3%
2008	13,911	15,998	15,073	115.0%	108.4%
2009	14,043	16,360	15,050	116.5%	107.2%
2010	13,655	16,113	14,490	118.0%	106.1%
2011	13,451	15,535	14,261	115.5%	106.0%
2012	13,431	15,579	14,149	116.0%	105.4%
2013	13,371	15,644	14,250	117.0%	106.6%
2014	13,719	16,051	14,594	117.0%	106.4%
2015	13,793	16,138	14,760	117.0%	107.0%
2016	13,705	16,103	14,555	117.5%	106.2%
2017	13,534	15,970	14,487	118.0%	107.0%



C.2.3 Long Island Power Authority (LIPA)

Table C.8 LIPA ICAP to UCAP Translation

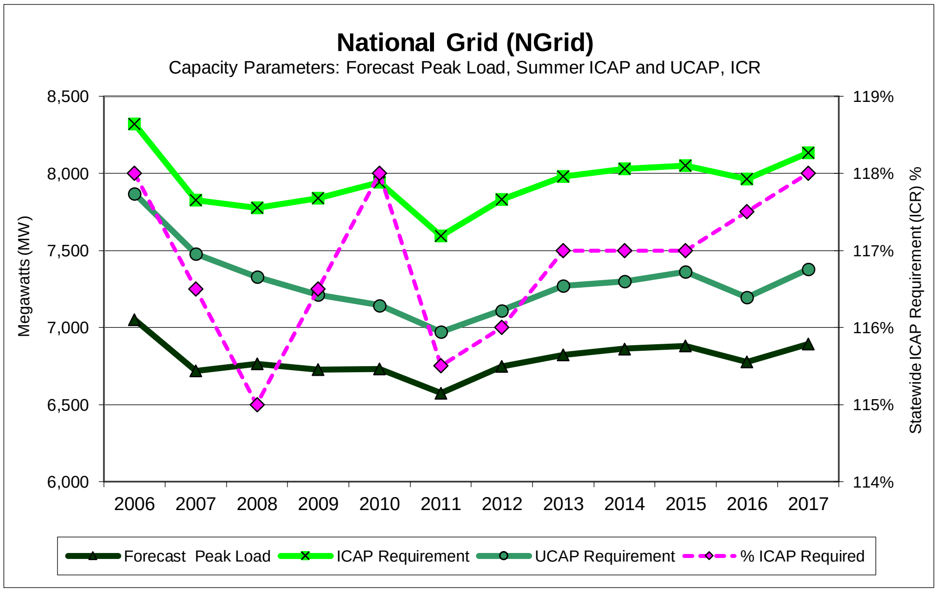
Year	Forecast Peak Load (MW)	ICAP Requirement (MW)	UCAP Requirement (MW)	%ICAP of Forecast Peak	%UCAP of Forecast Peak
2006	5,406	6,379	6,033	118.0%	111.6%
2007	5,322	6,200	5,923	116.5%	111.3%
2008	5,359	6,163	5,807	115.0%	108.4%
2009	5,432	6,328	5,821	116.5%	107.2%
2010	5,286	6,238	5,609	118.0%	106.1%
2011	5,404	6,242	5,730	115.5%	106.0%
2012	5,508	6,390	5,803	116.0%	105.4%
2013	5,449	6,375	5,807	117.0%	106.6%
2014	5,470	6,400	5,819	117.0%	106.4%
2015	5,541	6,483	5,930	117.0%	107.0%
2016	5,491	6,452	5,832	117.5%	106.2%
2017	5,427	6,404	5,809	118.0%	107.0%



C.2.4 National Grid (NGRID)

Table C.9 NGRID ICAP to UCAP Translation

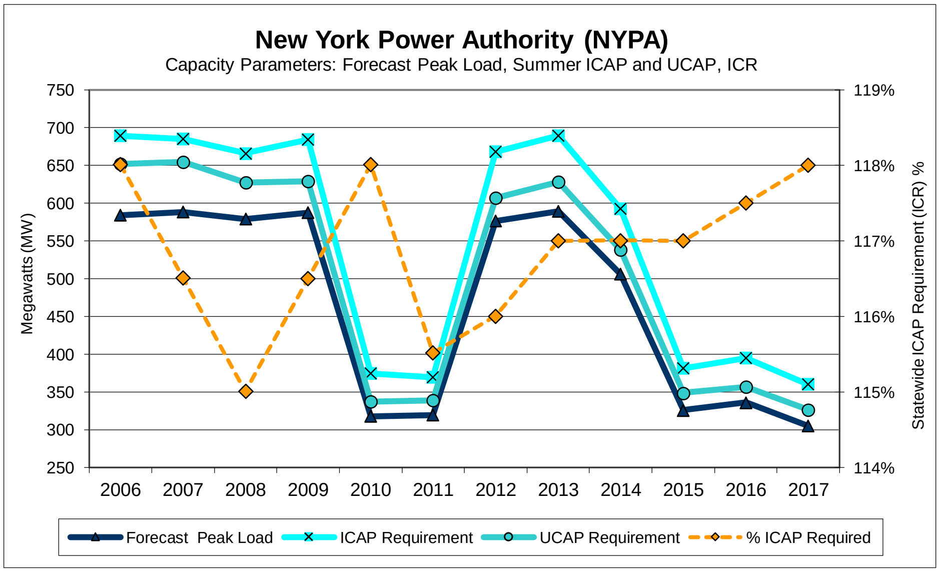
Year	Forecast Peak Load (MW)	ICAP Requirement (MW)	UCAP Requirement (MW)	%ICAP of Forecast Peak	%UCAP of Forecast Peak
2006	7,052	8,321	7,869	118.0%	111.6%
2007	6,719	7,827	7,478	116.5%	111.3%
2008	6,763	7,777	7,327	115.0%	108.4%
2009	6,728	7,839	7,211	116.5%	107.2%
2010	6,732	7,944	7,144	118.0%	106.1%
2011	6,575	7,594	6,971	115.5%	106.0%
2012	6,749	7,829	7,110	116.0%	105.4%
2013	6,821	7,981	7,270	117.0%	106.6%
2014	6,862	8,028	7,299	117.0%	106.4%
2015	6,880	8,050	7,363	117.0%	107.0%
2016	6,776	7,962	7,197	117.5%	106.2%
2017	6,891	8,132	7,376	118.0%	107.0%



C.2.5 New York Power Authority (NYPA)

Table C.10 NYPA ICAP to UCAP Translation

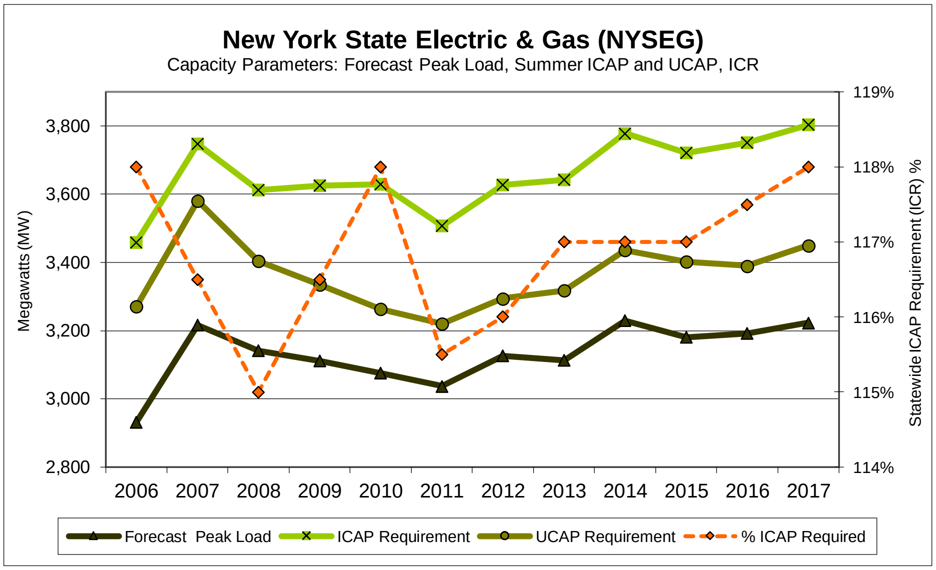
Year	Forecast Peak Load (MW)	ICAP Requirement (MW)	UCAP Requirement (MW)	%ICAP of Forecast Peak	%UCAP of Forecast Peak
2006	584	689	652	118.0%	111.6%
2007	588	685	655	116.5%	111.3%
2008	579	666	628	115.0%	108.4%
2009	587	684	629	116.5%	107.2%
2010	318	375	337	118.0%	106.1%
2011	320	369	339	115.5%	106.0%
2012	576	668	607	116.0%	105.3%
2013	589	690	628	117.0%	106.6%
2014	506	592	539	117.0%	106.4%
2015	326	381	349	117.0%	107.0%
2016	336	395	357	117.5%	106.2%
2017	305	360	327	118.0%	107.0%



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

Table C.11 NYSEG ICAP to UCAP Translation

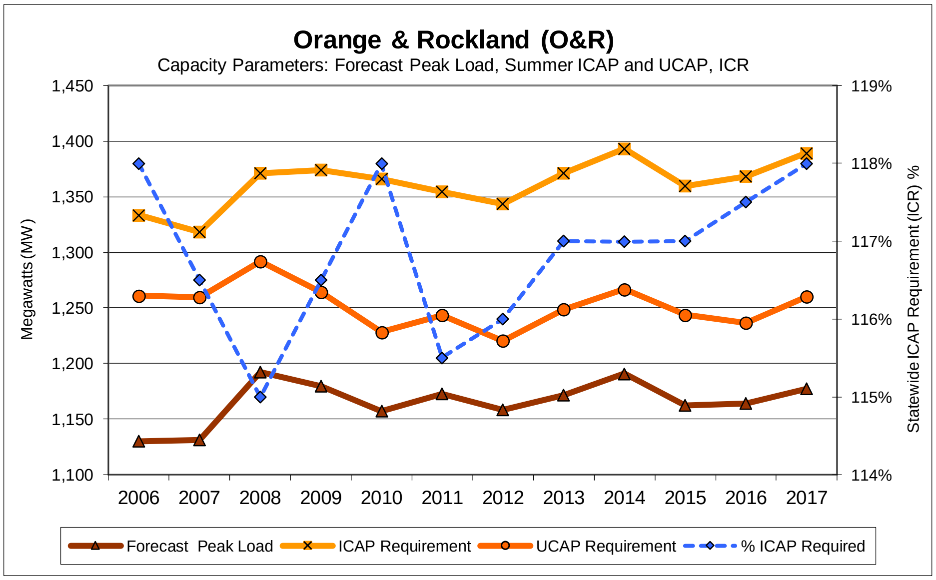
Year	Forecast Peak Load (MW)	ICAP Requirement (MW)	UCAP Requirement (MW)	%ICAP of Forecast Peak	%UCAP of Forecast Peak
2006	2,932	3,459	3,271	118.0%	111.6%
2007	3,217	3,748	3,581	116.5%	111.3%
2008	3,141	3,612	3,404	115.0%	108.4%
2009	3,112	3,625	3,335	116.5%	107.2%
2010	3,075	3,629	3,263	118.0%	106.1%
2011	3,037	3,508	3,220	115.5%	106.0%
2012	3,127	3,627	3,294	116.0%	105.4%
2013	3,113	3,643	3,318	117.0%	106.6%
2014	3,229	3,778	3,435	117.0%	106.4%
2015	3,180	3,720	3,403	117.0%	107.0%
2016	3,192	3,750	3,390	117.5%	106.2%
2017	3,223	3,803	3,450	118.0%	107.0%



C.2.7 Orange & Rockland (O & R)

Table C.12 O & R ICAP to UCAP Translation

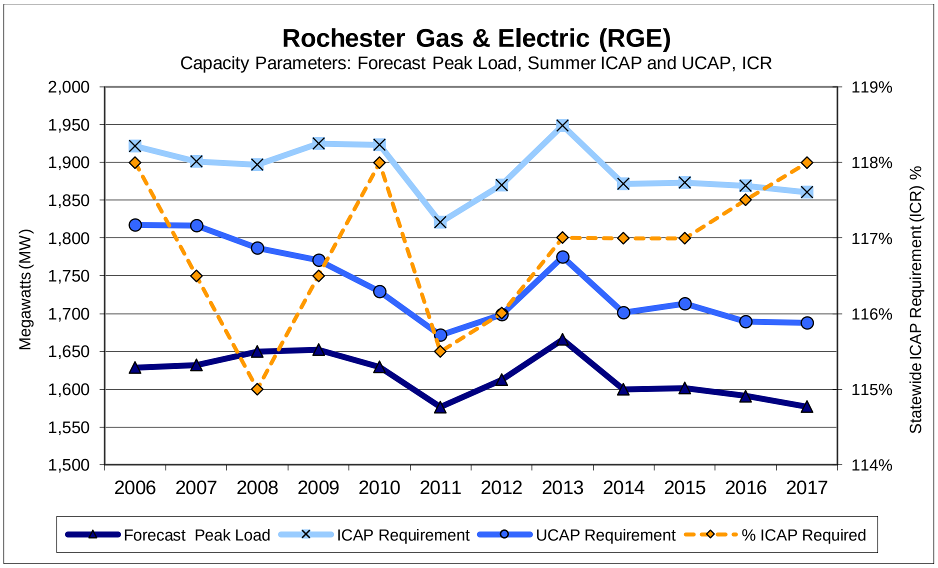
Year	Forecast Peak Load (MW)	ICAP Requirement (MW)	UCAP Requirement (MW)	%ICAP of Forecast Peak	%UCAP of Forecast Peak
2006	1,130	1,333	1,261	118.0%	111.6%
2007	1,132	1,318	1,259	116.5%	111.3%
2008	1,192	1,371	1,292	115.0%	108.4%
2009	1,180	1,374	1,264	116.5%	107.2%
2010	1,157	1,366	1,228	118.0%	106.1%
2011	1,173	1,355	1,243	115.5%	106.0%
2012	1,158	1,344	1,220	116.0%	105.4%
2013	1,172	1,371	1,249	117.0%	106.6%
2014	1,191	1,393	1,267	117.0%	106.4%
2015	1,162	1,360	1,244	117.0%	107.0%
2016	1,164	1,368	1,237	117.5%	106.2%
2017	1,177	1,389	1,260	118.0%	107.0%



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	1,629	1,922	1,817	118.0%	111.6%
2007	1,632	1,901	1,816	116.5%	111.3%
2008	1,649	1,897	1,787	115.0%	108.4%
2009	1,652	1,925	1,771	116.5%	107.2%
2010	1,630	1,923	1,729	118.0%	106.1%
2011	1,576	1,821	1,671	115.5%	106.0%
2012	1,612	1,870	1,699	116.0%	105.4%
2013	1,666	1,949	1,775	117.0%	106.6%
2014	1,600	1,872	1,702	117.0%	106.4%
2015	1,601	1,874	1,714	117.0%	107.0%
2016	1,591	1,869	1,690	117.5%	106.2%
2017	1,577	1,861	1,688	118.0%	107.0%



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 similar to 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. This data can be scaled to the nameplate capacity and assigned geographically to new and existing wind generation units.

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 doesn’t 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 PM to 6 PM 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 5-year period – 2012 through 2016 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).
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.

Term	Definition
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.
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.

Term	Definition
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.
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.

Term	Definition
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.