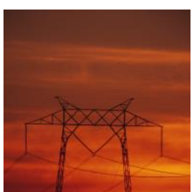
Appendices

New York Control Area Installed Capacity Requirement

For the Period May 2019 To April 2020



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New York State Reliability Council, LLC
Installed Capacity Subcommittee

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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

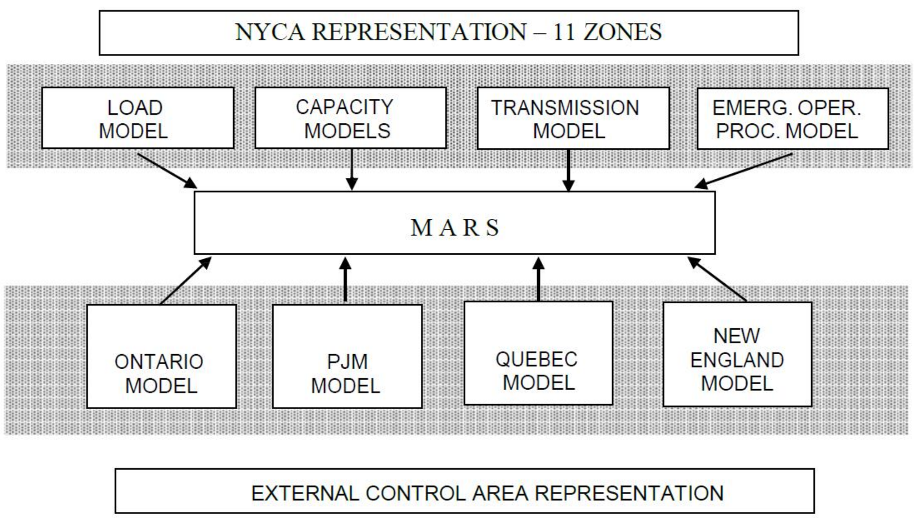

Table A.1 Modeling Details

#	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 2018 Gold Book[1]	Section A.3.2
4	Emergency Operating Procedures	Reduces load during emergency conditions to maintain operating reserves	NYISO	Section A.3.5
5	Zone Load Models	Hourly loads	NYCA load shape and peak forecasts	Section A.3.1
6	Load Uncertainty Model	Account for forecast uncertainty due to weather conditions	Historical data	Section A.3.1
7	Transmission Capacity Model	Emergency transfer limits of transmission interfaces between Zones	NYISO Transmission Studies	Section A.3.3
External Control Area Modeling				
8	Ontario, Quebec, ISONE, PJM Control Area Parameters	See items 9-12 in this table	Supplied by External Control Area	
9	External Control Area Capacity models	Generator models in neighboring Control Areas	Supplied by External Control Area	Section A.3.4
10	External Control Area Load Models	Hourly loads	Supplied by External Control Area	Section A.3.4
11	External Control Area Load Uncertainty Models	Account for forecast uncertainty due to economic conditions	Supplied by External Control Area	Section A.3.4
12	Interconnection Capacity Models	Emergency transfer limits of transmission interfaces between control areas.	Supplied by External Control Area	Section A.3.3

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

A.1 GE MARS

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

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

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

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

Sequential Monte Carlo simulation (used by GE-MARS) steps through the year chronologically, recognizing the status of equipment is not independent of its status in adjacent hours. Equipment forced outages are modeled by taking the equipment out of service for contiguous hours, with the length of the outage period being determined from the equipment's mean time to repair. Sequential simulation can model issues of concern that involve time correlations and can be used to calculate indices such as frequency and duration. It also models transfer limitations between individual areas.

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

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

Equation A.1 Transition Rate Definition

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

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

Equation A.2 Transition Rate Calculation Example

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

Table A.2 State Transition Rate Example

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

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

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

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

Each time a unit changes state, because of random state changes, the beginning or ending of planned outages, or mid-year installations or retirements, the total capacity available in the unit's area is updated to reflect the change in the unit's available capacity. This total capacity is then used in computing the area margins each hour.

A.1.1 Error Analysis

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

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

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

For this analysis, the Base Case required ~~531~~ replications to converge to a standard error of 0.05 and required ~~2455~~ replications to converge to a standard error of 0.025. For our cases, the model was run to ~~2500~~ 2750 replications at which point the daily LOLE of 0.100 days/year for NYCA was met with a standard error of 0.025. The confidence interval at this point ranges from ~~18.0~~% to ~~18.4~~%. It should be recognized that an ~~18.2~~16.8% IRM is in full compliance with the NYSRC Resource Adequacy rules and criteria (see Base Case Study Results section).

A.1.2 Conduct of the GE-MARS analysis

The study was performed using Version 3.~~21~~ 22.6 of the GE-MARS software program. This version has been benchmark tested by the NYISO.

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

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

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

A.2 Methodology

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

(1) Peak Load Forecast Methodology

The procedure for preparing the IRM forecast is very similar to that detailed in the NYISO Load Forecasting Manual for the ICAP forecast. The NYISO's Load Forecasting Task Force had two meetings in September ~~2017~~ 2018 to review weather-adjusted peaks for the summer of ~~2017~~ 2018 prepared by the NYISO and the Transmission Owners. Regional load growth factors (RLGFs) for ~~2018~~ 2019 were updated by most Transmission Owners; otherwise the same RLGFs that were used for the ~~2017~~ 2018 ICAP forecast were maintained. The ~~2018~~ 2019 forecast was produced by applying the RLGFs to each TO's weather-normalized peak for the summer of ~~2017~~2018.

The results of the analysis are shown in Table A-4. The ~~2017~~ 2018 IRM peak forecast was 32,868 MW. The actual peak of 31,936 MW (col. 2) occurred on August 29, 2018. After accounting for the impacts of weather and other factors, the weather-adjusted peak load was determined to be 32,444 MW (col. 6), 424 MW (1.3%) below the IRM forecast. The Regional Load Growth Factors are shown in column 9. The ~~2018~~ 2019 forecast for the NYCA is 32,488 MW (col. 12). The Locality forecasts are also reported in the second table below.

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

Table A.4 ~~2018~~ 2019 Final NYCA Peak Load Forecast

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2019 IRM Coincident Peak Forecast by Transmission District for NYSRC

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

2019 IRM Locality Peak Forecast by Transmission District for NYSRC

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

(2) Zonal Load Forecast Uncertainty

~~For~~ The ~~2018~~2019~~, new~~ load forecast uncertainty (LFU) models are the same models which were used last year~~were prepared~~. Due to below-average peak-producing weather in Summer 2017, the models were not updated. The LFU model~~s~~ for Zone K was~~were~~ provided by ~~Con Ed and~~ LIPA ~~for Zones H&I, J and K~~. The NYISO developed models for Zones A through ~~G~~ J and reviewed the ~~models for the other zones~~Zone K model. The results of these models are presented in Table A-5. Each row represents the probability that a given range of load levels will occur, on a per-unit basis, by zone. These results are presented graphically in Figure A-2.

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Table A.5 2019~~8~~ Load Forecast Uncertainty Models

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2019~~8~~ Load Forecast Uncertainty Models

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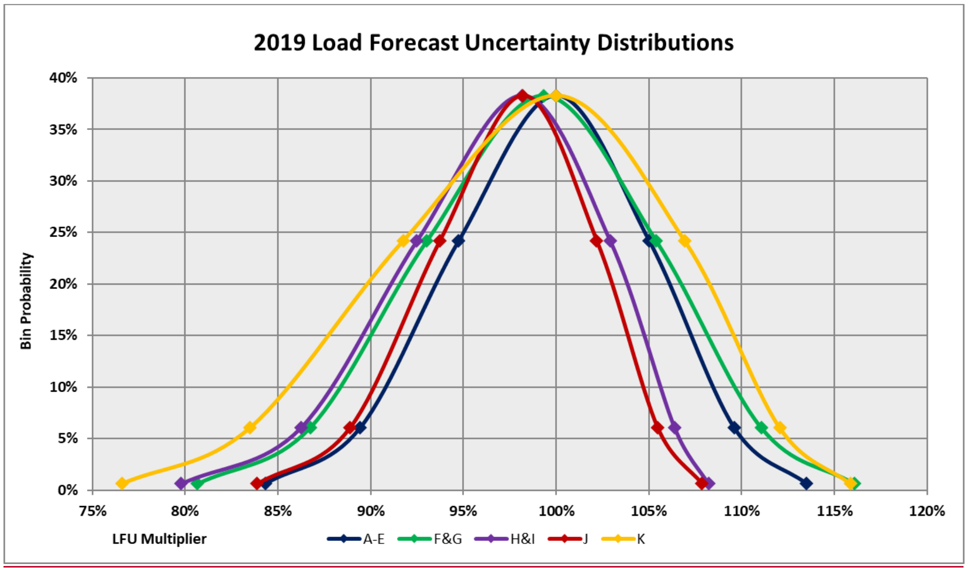
Bin	Probability	A-E	F&G	H&I	J	K
B7	0.62%	84.31%	80.67%	79.78%	83.88%	76.59%
B6	6.06%	89.44%	86.74%	86.24%	88.87%	83.51%
B5	24.17%	94.74%	93.03%	92.49%	93.71%	91.75%
B4	38.30%	100.00%	99.33%	98.17%	98.21%	100.00%
B3	24.17%	105.02%	105.41%	102.93%	102.19%	106.95%
B2	6.06%	109.59%	111.07%	106.39%	105.47%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

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

Figure A.2 LFU Distributions



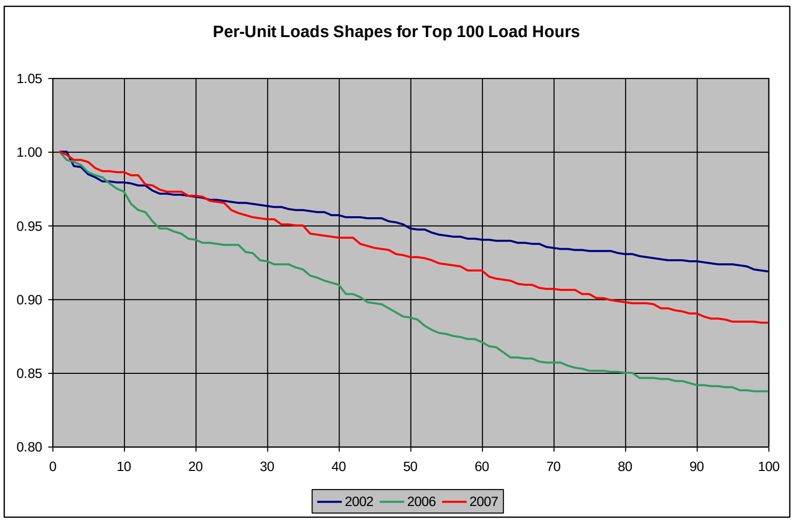
The Consolidated Edison models for Zones H, I & J are based on a peak demand with a 1-in-3 probability of occurrence (67th percentile). All other zones are designed at a 1-in-2 probability of occurrence of the peak demand (50th percentile). The methodology and results for determining the 2019 LFU models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

(3) Zonal Load Shape Models for Load Bins

Beginning with the 2014 IRM Study, multiple load shapes were used in the load forecast uncertainty bins. Three historic years were selected from those available, as discussed in the NYISO's 2013 report, 'Modeling Multiple Load Shapes in Resource Adequacy Studies'. The year 2007 was assigned to the first five bins (from cumulative probability 0% to 93.32%). The year 2002 was assigned to the next highest bin, with a probability of 6.06%. The year 2006 was assigned to the highest bin, with a probability of 0.62%. The three load shapes for the NYCA 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.

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~~ 2018 Load and Capacity Data Report is the primary data source for these resources. Table A.6 provides a summary of the capacity resource assumptions in the ~~2018~~ 20189 IRM study.

Table A.6 Capacity Resources

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

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

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

Parameter	2018 Study Assumption	2019 Study Assumption	Explanation
Gas Turbine Ambient 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	Actual hourly plant output over the period 2012-2016.	Actual hourly plant output over the period 2013-2017.	Program randomly selects a Hydro shape of hourly production over the years 2013-2017 for each model iteration.
Large Hydro	Probabilistic Model based on 5 years of GADS data	Probabilistic Model based on 5 years of GADS data	Transition Rates representing the Equivalent Forced Outage Rates (EFORd) during demand periods over the most recent five-year period (2013-2017)

(1) Generating Unit Capacities

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

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

(2) Planned Generator Units

One planned new non-wind generating unit, Arthur Kill Cogen, having a total capacity of 11.1 MW, is included in the 2019 IRM Study. In addition, increased ratings on Bethlehem Energy Center, Bayonne Energy Center II, East River 1, 2, and 6, and Nine Mile Point 2 totaled 209.3 MW.

(3) Wind Modeling

Wind generators are modeled as hourly load modifiers using hourly production data over the period 2013-2017. Each calendar production year represents an hourly wind shape for each wind facility from which the GE MARS program will randomly select. New units will use the zonal hourly averages of current units within the same zone. Characteristics of this data indicate a capacity factor of approximately 15.7% during the summer peak hours. As shown in table A.7, a total of 1891.7 MW of installed capacity associated with wind generators is included in this study including 158.3 MW of planned new wind capacity.

Table A.7 Wind Generation

Table A.7 - 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
Jericho Rise	D	77.7	77.7	77.7
		1735.9	**1739.5**	**1733.4**
New and Proposed IRM Study Wind Units				
Copenhagen Wind	E	79.9	79.9	79.9
Arkwright Summit	A	78.4	78.4	78.4
		158.3	**158.3**	**158.3**
Non - ICAP Participating Wind Units				
	Zone	**CRIS (MW)**	**Nameplate Capability (MW)**	**CRIS adusted value from 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		1894.2	1969.4	**1891.7**

(4) Solar Modeling

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

(5) Retirements/Deactivations/ ICAP ~~Ineligable~~Ineligible

~~Three units in Zone K totaling 137 MW were~~There are no units slated to retire before the summer of ~~2018~~2019. ~~All t~~Three units totaling 399.2 MW have become deactivated. ~~rescinded their notice of retirement and are expected to remain fully operational through the 2018 capability year.~~ In addition, ten plants totaling 389.4 MW, have been placed in ICAP ineligible status and are removed from this study ~~while their final dispositions are determined.~~

(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~~ 2019 IRM Study.

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

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

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

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

The unit forced outage states for the most of the NYCA units were obtained from the five-year NERC GADS outage data collected by the NYISO for the years ~~2012~~ 2013 through ~~2016~~2017. This hourly data represents the availability of the units for all hours. From this, full and partial outage states and the frequency of occurrence were calculated and put in the required format for input to the GE-MARS program. ~~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

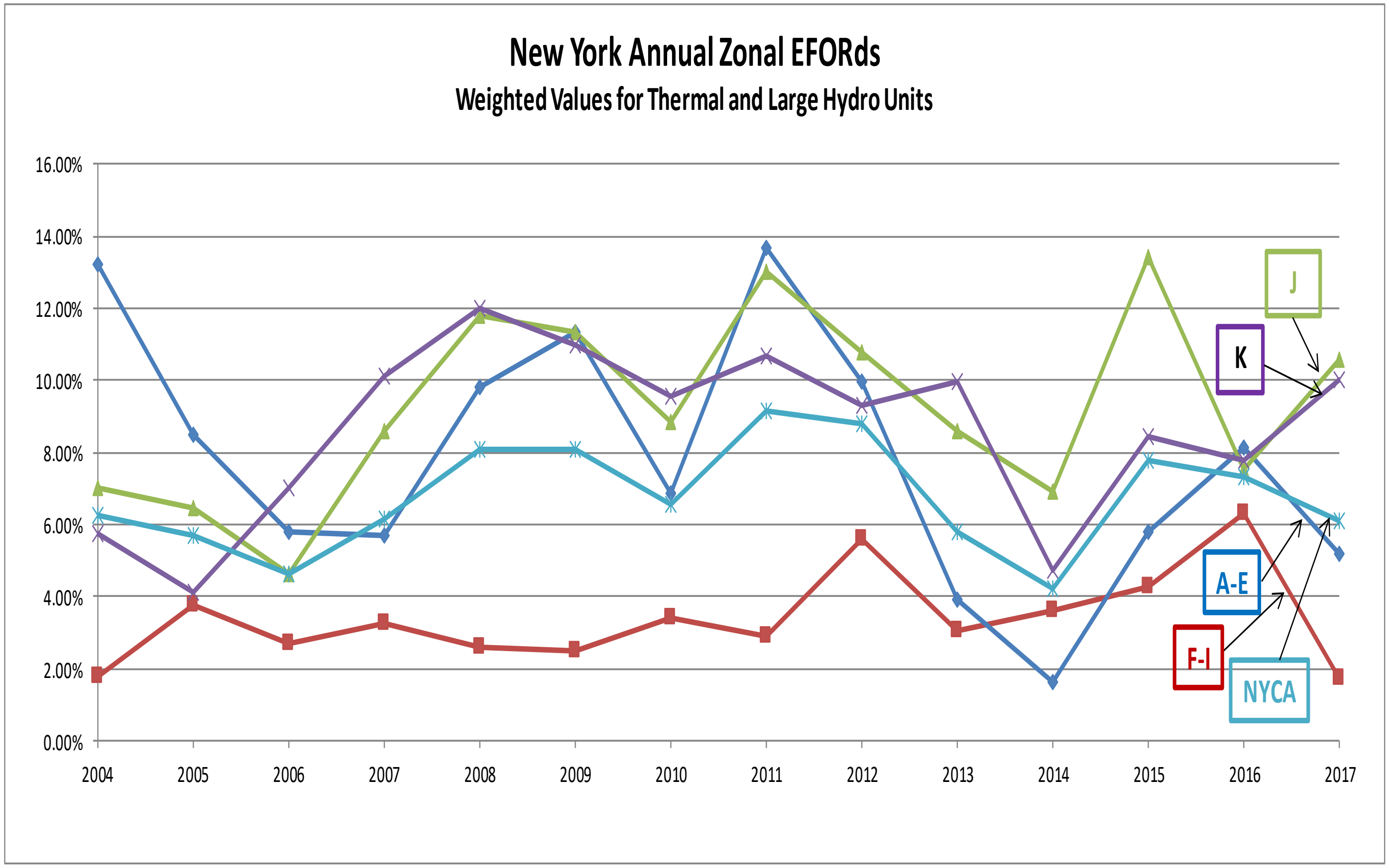


Figure A.5 Five-Year Zonal EFORds

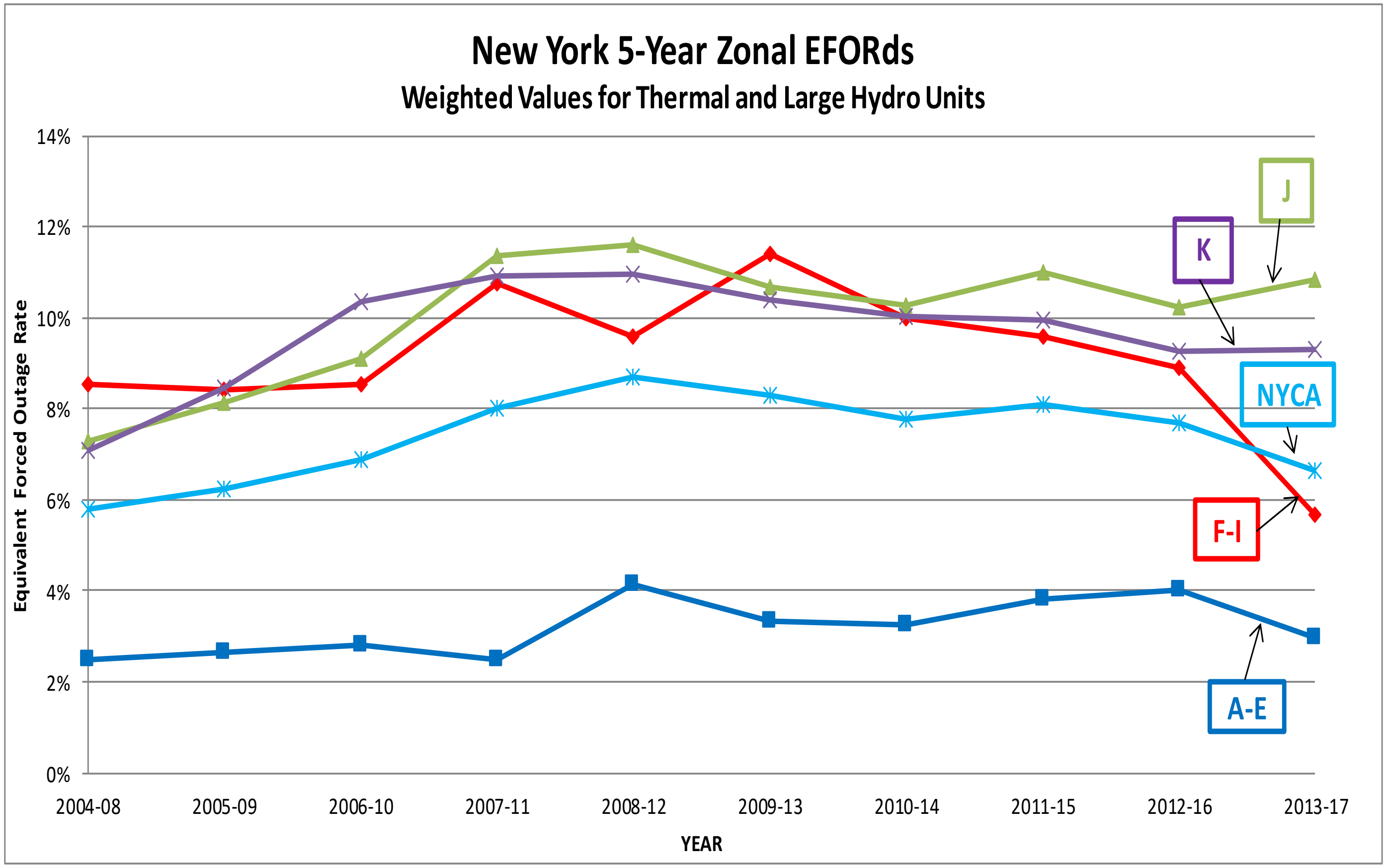


Figure A.6 NYCA Annual Availability by Fuel

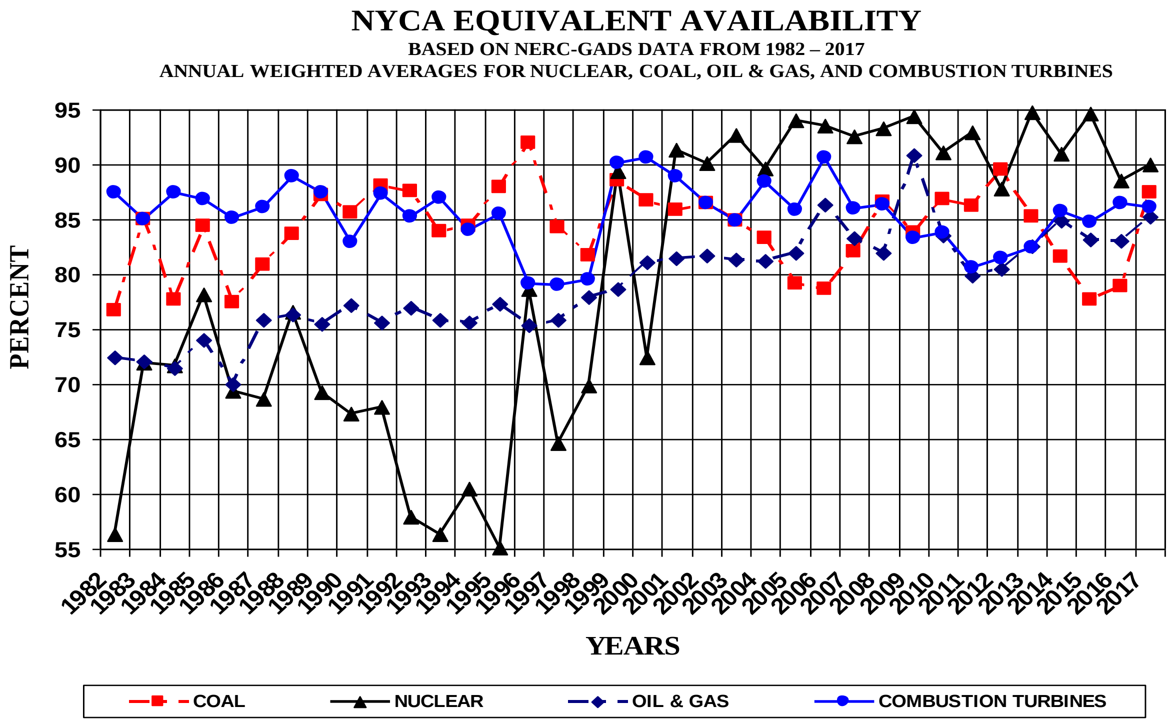


Figure A.7 NYCA Five-Year Availability by Fuel

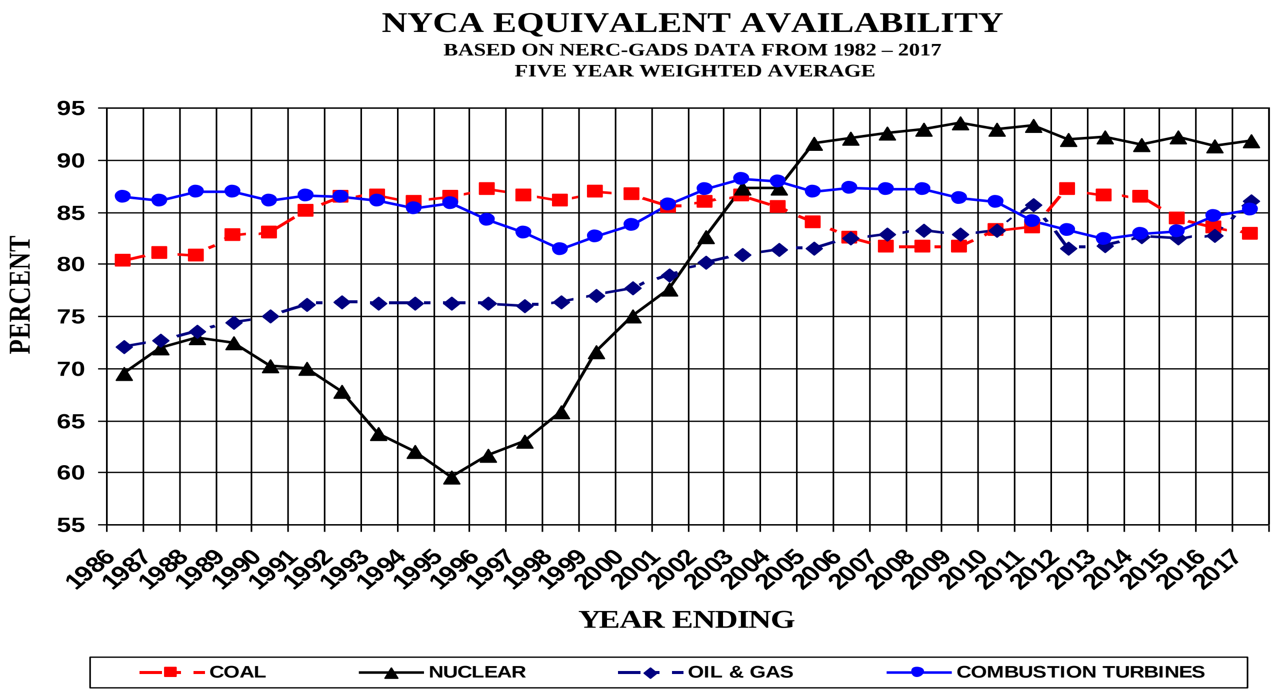


Figure A.8 NERC Annual Availability by Fuel

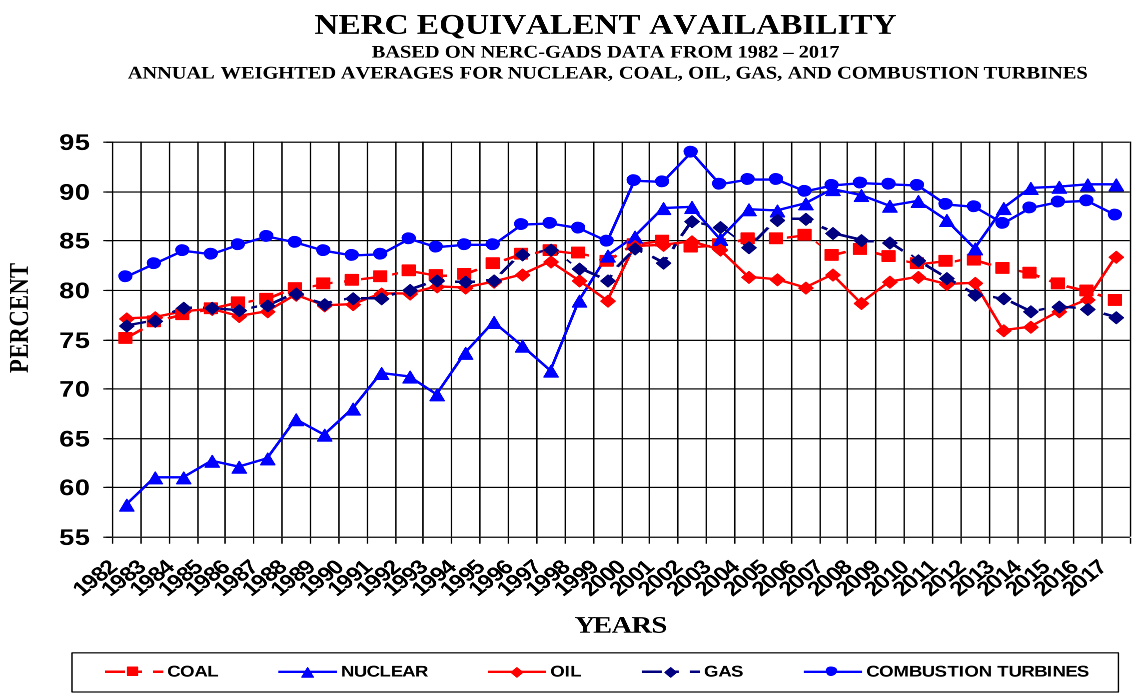
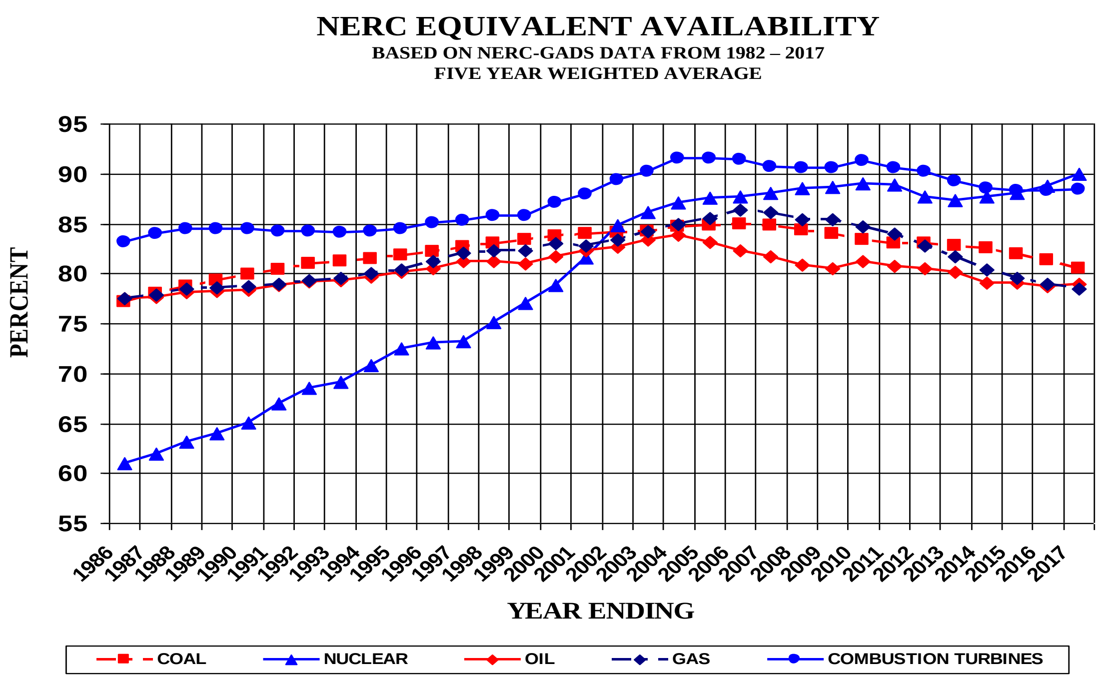


Figure A.9 NERC Five-Year Availability by Fuel



(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 2017 period for the NYCA generators.

Typically, generator owners do not schedule maintenance during the summer peak period. However, it is highly probable that some units will need to schedule maintenance during this period. Each year, the previous summer capability period is reviewed to determine the scheduled maintenance MW during the previous peak period. An assumption is determined as to how much to model in the current study. For the ~~2018~~ 2019 IRM Study, a nominal 50 MW of summer maintenance is modeled. The amount is nominally divided equally between Zone J and Zone K. Figure A.11 shows the weekly scheduled maintenance for the ~~2016~~ 2018 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 gas 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.

(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

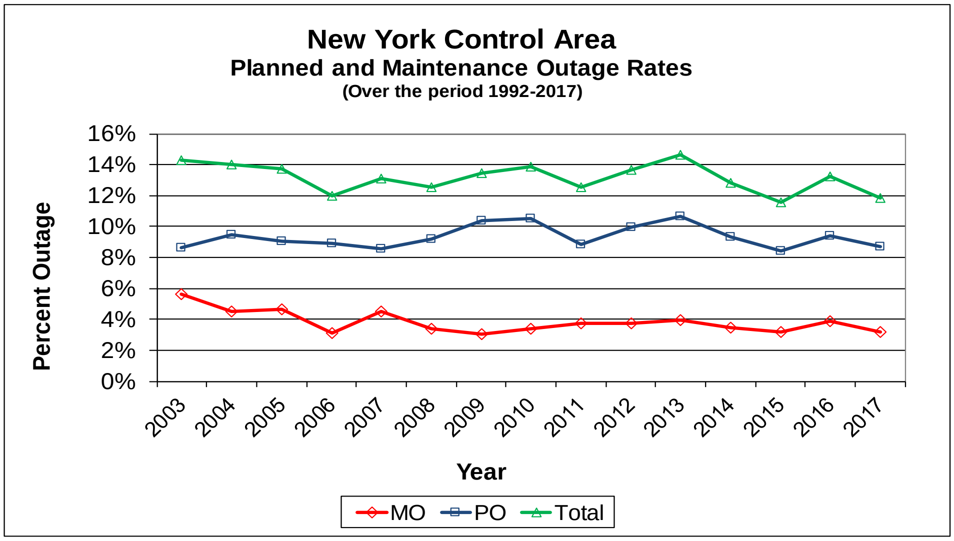
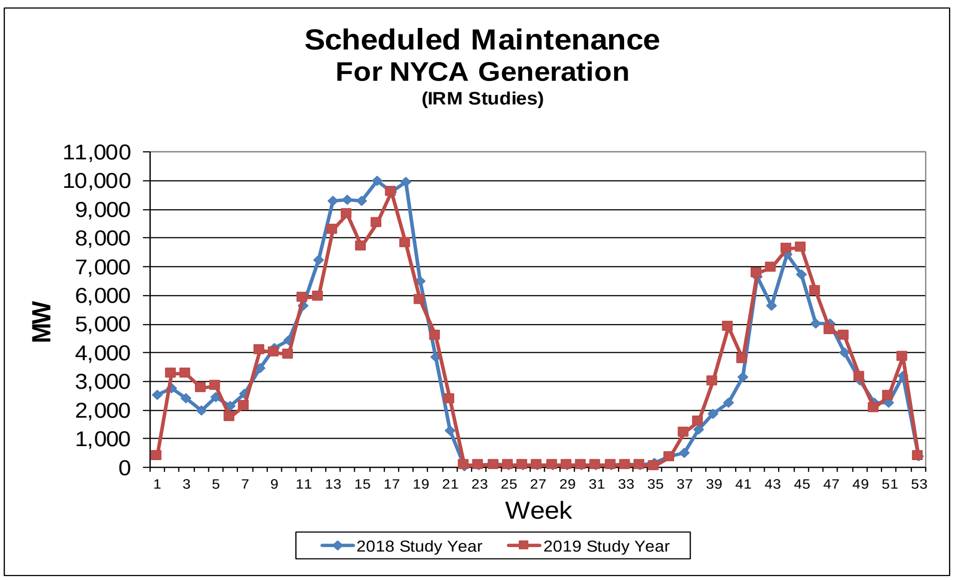


Figure A.11 Scheduled Maintenance



A.3.3 Transmission System Model

A detailed transmission system model is represented in the GE-MARS topology. The transmission system topology, which includes eleven NYCA Zones and four External Control Areas, along with transfer limits, is shown in Figure A.12. The transfer limits employed for the ~~2018~~ 2019 IRM Study were developed from emergency transfer limit analyses included in various studies performed by the NYISO and based upon input from Transmission Owners and neighboring regions. The transfer limits are further refined by other assessments conducted by the NYISO. The assumptions for the transmission model included in the ~~2018~~ 2019 IRM Study are listed in Table A.8.

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.8 Transmission System Model

Parameter	~~2017~~ 2018 Model Assumptions	~~2018~~ 2019 Model Assumptions Recommended	Basis for Recommendation
Interface Limits	All changes reviewed and commented on by TPAS	~~All changes reviewed and commented on by TPAS~~No Changes from the 2018 Model	Based on 2017 Operating Study, 2016 Operations Engineering Voltage Studies, 2016 Reliability Planning Process, and additional analysis including interregional planning initiatives
Cable Forced Outage Rates	All existing Cable EFORs updated for NYC and LI to reflect most recent five-year history	All existing Cable EFORs updated for NYC and LI to reflect most recent five-year history	Based on TO analysis or NYISO analysis where applicable
UDR line Unavailability	Five year history of forced outages	Five year history of forced outages	NYISO/TO review

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

Figure A.12 2018 IRM Topology

2019 IRM Topology (Summer Limits)

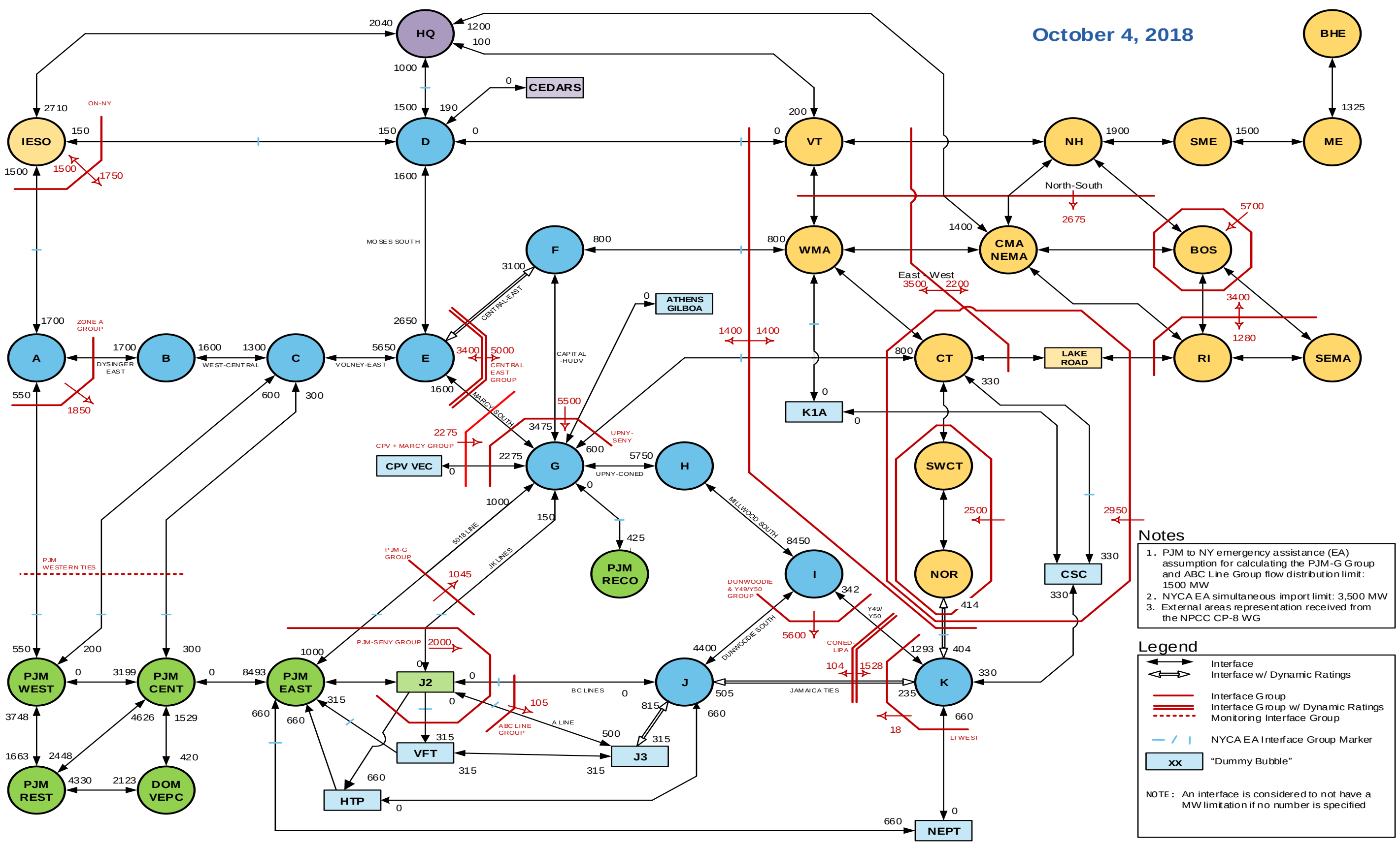


Figure A.13 Dynamic Interface Ratings Information

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	E_to_F		E_to_FG	
Available	Fwd	Rev	Fwd	Rev
6	3,100	1,999	5,000	3,400
5	3,050	1,999	4,925	3,400
4	2,990	1,999	4,840	3,400
3	2,885	1,999	4,685	3,400
2	2,770	1,999	4,510	3,400
Otherwise:	2,645	1,999	4,310	3,400

Staten Island Import Limits, AK and Linden CoGen Units

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

Long Island Import Limits, Northport

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

Long Island Import Limits, Barret Steam Units

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

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.9 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.10 Distribution of Power Transfers between PJM and NY

PJM-NY JOA Flow Distribution (Jan 31, 2017 Filing)	**RECO Load Deliveries**	**PJM-NY Emergency Assistance**
PJM-NY Western Ties	20%	32%
5018 Line	80%	32%
JK Lines	0%	15%
A Line	0%	7%
BC Lines	0%	14%

3. Other Modeling Changes

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.11 below.

Table A.11 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 (3,500 MW for this IRM study) is based on a recommendation from the ICS and the NYSIO that considers the amount of ten-minute reserves that are available in the external Control Areas above an Area's required reserve, along with other factors.

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

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

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

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

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

Table A.12 External Area Representations

Parameter	2018 Study Assumption	2019 Study Assumption	Explanation
Capacity Purchases	Grandfathered amounts: PJM – 1080 MW HQ – 1110 MW All contracts model as equivalent contracts	Grandfathered amounts: PJM – 1080 MW HQ – 1110 MW All contracts model as equivalent contracts	Grandfathered Rights, ETCNL, and other FERC identified rights.
Capacity Sales	Long term firm sales of ~~284.9~~283.8 MW	Long term firm sales of ~~283.8~~279.3 MW	These are long term federally monitored contracts.
External Area Modeling	Single Area representations for Ontario and Quebec. Four areas modeled for PJM. Thirteen zones modeled for New England	Single Area representations for Ontario and Quebec. Five areas modeled for PJM. Thirteen zones modeled for New England	The load and capacity data is provided by the neighboring Areas. This updated data may then be adjusted as described in Policy 5
Reserve Sharing	All NPCC Control Areas have indicated that they will share reserves equally 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.13, below, shows the final reserve margins and LOLEs for the Control Areas external to NYCA. The ~~2018~~ 2019 external area model also includes a 3,500 MW limit for emergency assistance (EA) imports during any given hour. However, as per Table 6.1 of the IRM study report, the amount EA available to the NYCA ~~decreased~~ increased the IRM VS. the ~~2017~~ 2018 study. This can be most likely attributed to increased transfer capability on some external ties and a lower LOLE for New England.

Table A.13 Outside World Reserve Margins

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

*This is the summer margin.

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

A.3.5 Emergency Operating Procedures (EOPs)

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

The values in Table A.15 are based on a NYISO forecast that incorporates ~~2017~~ 2018 (summer) operating results. This forecast is applied against a ~~2018~~ 2019 peak load forecast of 32,~~868~~ 488 MW. The table shows the most likely order that these steps will be initiated. The actual order will depend on the type of the emergency. The amount of assistance that is provided by EOPs related to load, such as voltage reduction, will vary with the load level.

Table A.14 Assumptions for Emergency Operating Procedures

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

Parameter	2018 Study Assumption	2019 Study Assumption	Explanation
		months. Limit to five calls per month	
EOP Procedures	609.6 MW of non-SCR/non-EDRP resources	713.4 MW of non-SCR/non-EDRP resources	Based on TO information, measured data, and NYISO forecasts

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

Table A.15 Emergency Operating Procedures Values

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

** The SCR's are modeled as monthly values. The value for July is 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 32,868 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.~~R~~2 and monitored by the NYISO, supplement the statewide IRM requirement. This report using the unified methodology determines the minimum locational requirements for different levels of installed reserve. The NYSRC chooses the IRM to be used for the coming year and the NYISO chooses the final value of the locational requirements to be met by the LSEs.

A.3.7 Special Case Resources and Emergency Demand Response Program

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

Table A.16 SCR Performance

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

The Emergency Demand Response Program (EDRP) is a separate program that allows registered interruptible loads and standby generators to participate on a voluntary basis and be paid for their ability to restore operating reserves.

GE-MARS model accounts for SCRs and 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 registered value is ~~1219~~ 1309 MW. This value is the result of applying historic growth rates to the latest participation numbers. The effective value of 903 MW is used in the model for this month.

EDRPs are modeled as a ~~3~~ 1 MW EOP step in July and August (and they are also further discounted in other months) with a limit of five calls per month. This EOP is discounted from the forecast registered amount of ~~16~~ 5.5 MW based on actual experience.

A.4 MARS Data Scrub

A.4.1 GE Data Scrub

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

Table A.17 GE MARS Data Scrub

Item	Description	Disposition	Data Change	Post PBC* Affect
1	Unit name changes between 2018 and 2019 study were identified	Name changes were reviewed and accepted	No	N/A
2	Three units added with 0 MW of capacity	Capacities were checked and were correct.	No	N/A
3	Rockville Center (Charles Keller) unit 8 not in list of deactivated units	Unit retired and will be added to assumptions matrix. Retirement correctly captured in model.	No	N/A
4	Stony Book rating not documented in assumptions matrix	Variance in capacity & load are captured but not called out. More description may be needed in report.	No	N/A
5	Linden VFT modeled as single unit versus two units last year	Under review.	No	N/A
6	Six units identified with large EFORd change	One unit retired and the other five went through a second review and were found correct in the model	No	N/A

Item	Description	Disposition	Data Change	Post PBC* Affect
7	Energy, even though not an explicit IRM assumption, appears higher in model than gold book forecast	A known effect of growing historical load shapes to meet future peaks. Initiative underway to study alternatives.	No	N/A

*Preliminary Base Case

A.4.2 NYISO Data Scrub

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

Table A.18 NYISO MARS Data Scrub

Item	Description	Disposition	Data Change	Post PBC* Affect
1				
2				
3				
4				
5				
6				
7				
8				
9				
10				
11				
12				

*Preliminary Base Case

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

A.4.3 Transmission Owner Data Scrub

In addition to the above reviews, two transmission owners scrub the data and assumptions from a masked database provided. Many of their findings reiterated the previous findings. Table A.19 shows their unique results. These findings are based on a review of the preliminary base case not the final base case.

Table A.19 Transmission Owner Data Scrub

Item	Description	Disposition	Data Change	Post PBC* Affect

*Preliminary Base Case

**These results discussed as the parametric changes from the PBC to the FBC

Appendix B

Details of Study Results

B. Details for Study Results

B.1 Sensitivity Results

Table B.1 summarizes the ~~2018~~ 2019 Capability Year IRM requirements under a range of assumption changes from those used for the base case. The base case utilized the computer simulation, reliability model, and assumptions described in Appendix A. The sensitivity cases determined the extent of how the base case required IRM would change for assumption modifications, either one at a time, or in combination. The methodology used to conduct the sensitivity cases was to start with the preliminary base case ~~18.7~~16.9 % IRM results then add or remove capacity from all zones in NYCA until the NYCA LOLE approached criterion. The values in Table B.1 are the sensitivity results adjusted to the ~~18.2~~16.8% final base case. A full tan 45 analysis was conducted for cases 9 and 12.

Table B.1 Sensitivity Case Results

Case	Description	IRM (%)	NYC (%)	LI (%)
0	**2019 Final Base Case**	16.8	82.6	101.5
	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**	25.0	88.3	109.2
	This case examines a scenario where the NYCA system is isolated and receives no emergency assistance from neighboring control areas (New England, Ontario, Quebec, and PJM). UDRs are allowed.			
2	**No Internal NYCA Transmission Constraints (Free Flow System)**	14.4	80.9	99.3
	This case represents the "Free-Flow" NYCA case where internal transmission constraints are eliminated and measures the impact of transmission constraints on statewide IRM requirements.			
3	**No Load Forecast Uncertainty**	9.2	77.2	94.4
	This scenario represents "perfect vision" for 2019 peak loads, assuming that the forecast peak loads for NYCA have a 100% probability of occurring. The results of this evaluation help to quantify the effects of weather on IRM requirements.			
4	**Remove all wind generation**	12.0	83.3	102.4
	Freeze J & K at base levels and adjust capacity in the upstate zones. This shows the impact that the wind generation has on the IRM requirement.			
5	**No SCRs & no EDRPs**	13.9	79.1	101.6
	Shows the impact of SCRs and EDRPs on IRM.			

Case	Description	IRM (%)	NYC (%)	LI (%)
6	**Remove CPV valley from service**	17.0	83.1	101.9
	Remove the addition of CPV Valley (678 MW) from the base case due to air permit uncertainty.			
7	**Limit Emergency Assistance from PJM to all of NYCA to 1500 MW**	16.8	82.6	101.5
	This case uses a grouped interface of all PJM to NYCA import ties and restricts the grouping to a limit of 1500 MW			
8	**Remove the 3500 MW EA Limit into NYCA**	16.5	82.4	101.2
	Remove the 3500 MW Emergency Assistance grouped limit entering NYCA from its neighbors. UDRs remain in New York.			
9	**Remove the B and C lines from service (tan 45)***	16.6	85.2	102.1
	Due to uncertain outage duration, reduce the B and C line ratings to Zone J to 0 MW. Decrease the NYC import grouping from 315 MW to 105 MW.			
10	**Combine Cedars and Quebec areas**	16.9	82.6	101.6
	In anticipation of the 2020 IRM, create one Area with both Quebec and the Cedars combined. Increase tie capability to 1690 MW.			
11	**Remove public appeals from model**	17.2	83.1	102.1
	Remove 80 MW of public appeals from the EOP steps in the model.			
12	**Incorporate Quebec to New England wheel (tan 45)**	17.1	82.7	101.7
	Reduce the HQ to zone D rating by 300 MW and increase to NE to Zone F by 300 MW to account for this capacity transaction.			

B.2 Impacts of Environmental Regulations

B.2.1 Regulatory Policy Activities

Federal, state and local government regulatory programs may impact the operation and reliability of the BPTF. Compliance with state and federal regulatory initiatives and permitting requirements may require investment by the owners of New York's existing thermal power plants. If the owners of those plants have to make considerable investments, the cost of these investments could impact whether they remain available in the NYISO's markets and therefore potentially affect the reliability of the BPTF. The purpose of this section is to review the status of regulatory programs and their potential grid impacts. The following regulatory programs – each at various points in the development and implementation – are summarized on the next page:

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

B.2.2 Clean Energy Standard

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

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

B.2.3 New York City Residual Oil Elimination

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

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

B.2.4 Offshore Wind Development

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

B.2.5 Part 251: Carbon Dioxide Emissions Limits

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

B.2.6 Regional Greenhouse Gas Initiative (RGGI)

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

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

B.2.7 Smog-Forming Pollutants Rule Proposal

In his 2018 State of the State address, Governor Cuomo announced that the DEC will propose emissions requirements intended to reduce emissions of smog-forming pollutants from peaking units, and as much as 3,500 MW could be affected.

The NYISO will continue to monitor the development of new emissions rules that may impact the operation of peaking units.

B.2.8 Storage Deployment Target

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

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

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

B.3 Frequency of Implementing Emergency Operating Procedures

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

Table B.2 Implementation of EOP steps

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

Appendix C

ICAP to UCAP Translations

C. ICAP to UCAP Translation

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

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

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

Table C.1 Historical NYCA Capacity Parameters

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

C.1 NYCA and NYC and LI Locational Translations

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

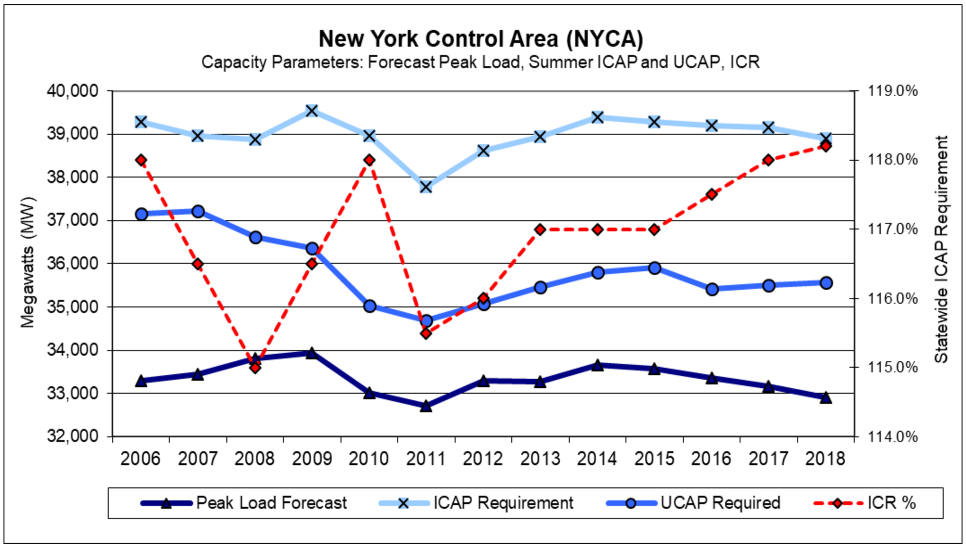
Locational ICAP/UCAP calculations are produced for NYC, LI, G-J and the entire NYCA. Exhibits C.1.1 through C.1.4 summarizes the translation of ICAP requirements to UCAP requirements for these areas. The charts and tables included in these exhibits utilize data from the 2006 through 2017 summer capability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

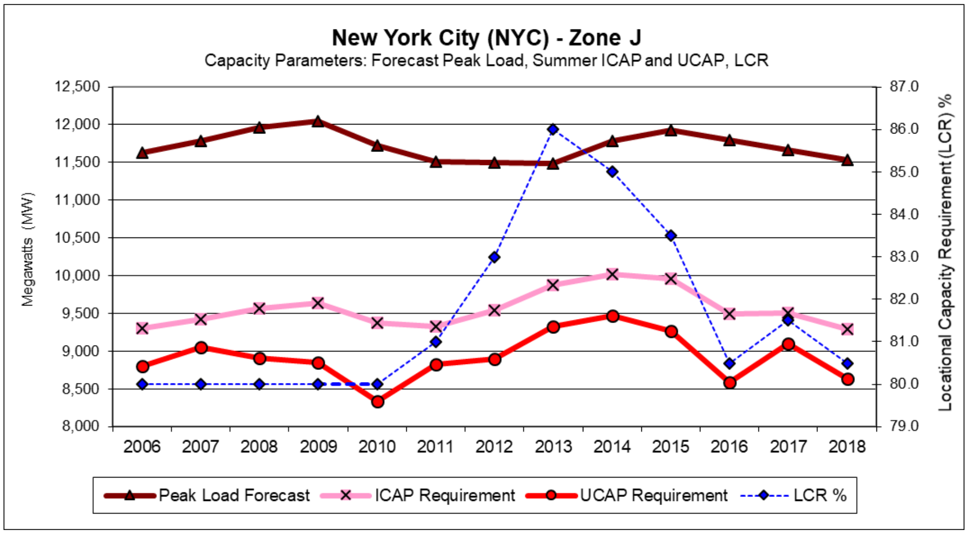
Year	Forecast Peak Load (MW)	Installed Capacity Requirement (%)	Derate Factor	ICAP Requirement (MW)	UCAP Requirement (MW)	Effective UCAP (%)
2006	33,295	118.0	0.0543	39,288	37,154	111.6
2007	33,447	116.5	0.0446	38,966	37,228	111.3
2008	33,809	115.0	0.0578	38,880	36,633	108.4
2009	33,930	116.5	0.0801	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
2018	32,903	118.2	0.0856	38,891	35,562	108.1



C.1.2 New York City ICAP to UCAP Translation

Table C.3 New York City ICAP to UCAP Translation

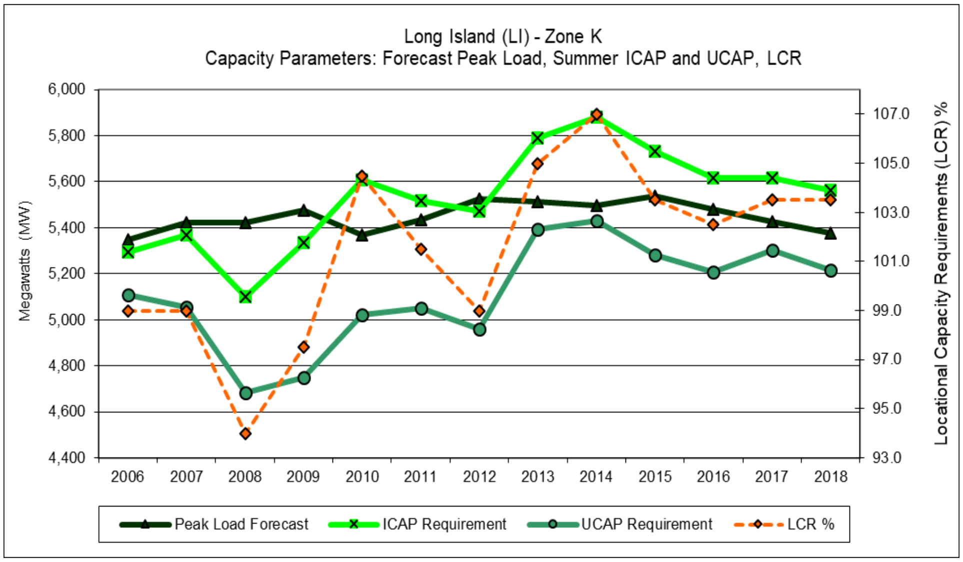
Year	Forecast Peak Load (MW)	Locational Capacity Requirement (%)	Derate Factor	ICAP Requirement (MW)	UCAP Requirement (MW)	Effective UCAP (%)
2006	11,628	80.0	0.0542	9,302	8,798	75.7
2007	11,780	80.0	0.0388	9,424	9,058	76.9
2008	11,964	80.0	0.0690	9,571	8,911	74.5
2009	12,050	80.0	0.0814	9,640	8,855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



C.1.3 Long Island ICAP to UCAP Translation

Table C.4 Long Island ICAP to UCAP Translation

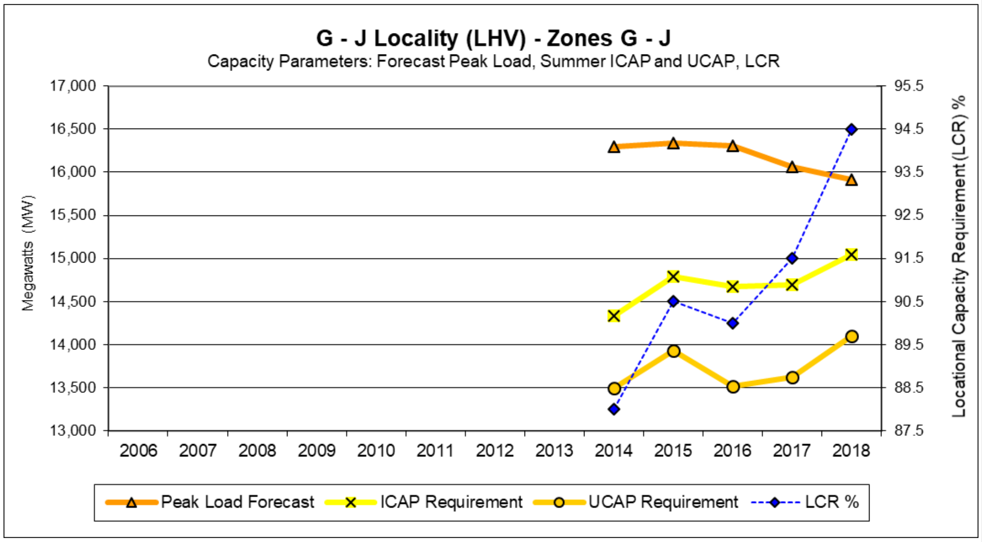
Year	Forecast Peak Load (MW)	Locational Capacity Requirement (%)	Derate Factor	ICAP Requirement (MW)	UCAP Requirement (MW)	Effective UCAP (%)
2006	5,348	99.0	0.0348	5,295	5,110	95.6
2007	5,422	99.0	0.0580	5,368	5,056	93.3
2008	5,424	94.0	0.0811	5,098	4,685	86.4
2009	5,474	97.5	0.1103	5,337	4,749	86.8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



C.1.4 GHIJ ICAP to UCAP Translation

Table C.5 GHIJ ICAP to UCAP Translation

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

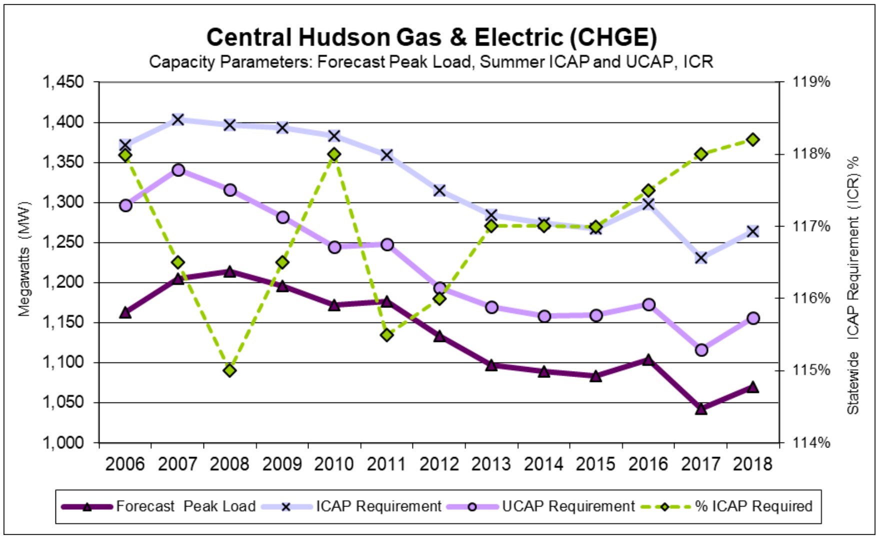


C.2 Transmission Districts ICAP to UCAP Translation

C.2.1 Central Hudson Gas & Electric

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

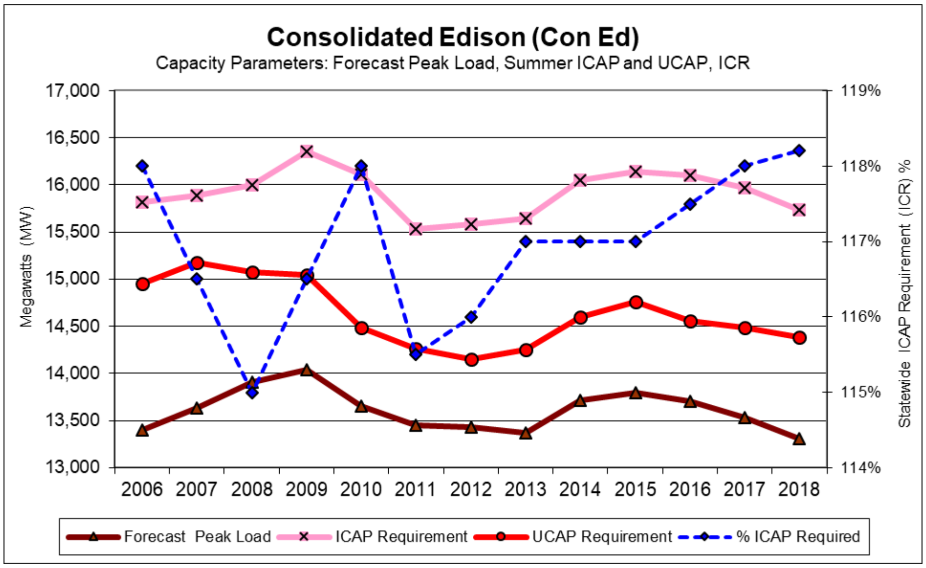
Year	Forecast Peak Load (MW)	ICAP Requirement (MW)	UCAP Requirement (MW)	%ICAP of Forecast Peak	%UCAP of Forecast Peak
2006	1,162.5	1,371.7	1,297.3	118.0%	111.6%
2007	1,205.0	1,403.8	1,341.2	116.5%	111.3%
2008	1,214.1	1,396.2	1,315.5	115.0%	108.4%
2009	1,196.3	1,393.7	1,282.1	116.5%	107.2%
2010	1,172.3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



C.2.2 Consolidated Edison (Con Ed)

Table C.7 Con Ed ICAP to UCAP Translation

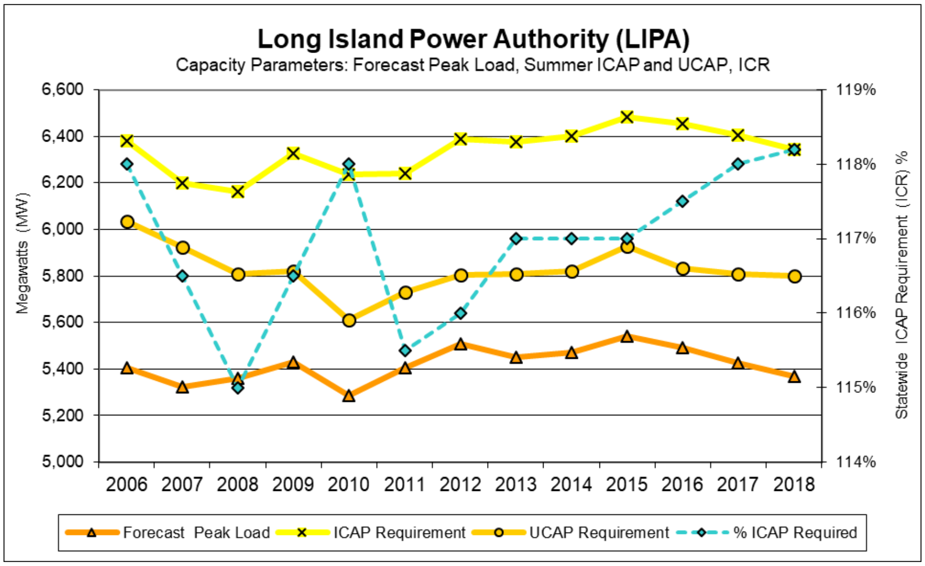
Year	Forecast Peak Load (MW)	ICAP Requirement (MW)	UCAP Requirement (MW)	%ICAP of Forecast Peak	%UCAP of Forecast Peak
2006	13,400.0	15,812.0	14,953.4	118.0%	111.6%
2007	13,633.6	15,883.1	15,174.7	116.5%	111.3%
2008	13,911.1	15,997.8	15,073.1	115.0%	108.4%
2009	14,043.0	16,360.1	15,049.6	116.5%	107.2%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



C.2.3 Long Island Power Authority (LIPA)

Table C.8 LIPA ICAP to UCAP Translation

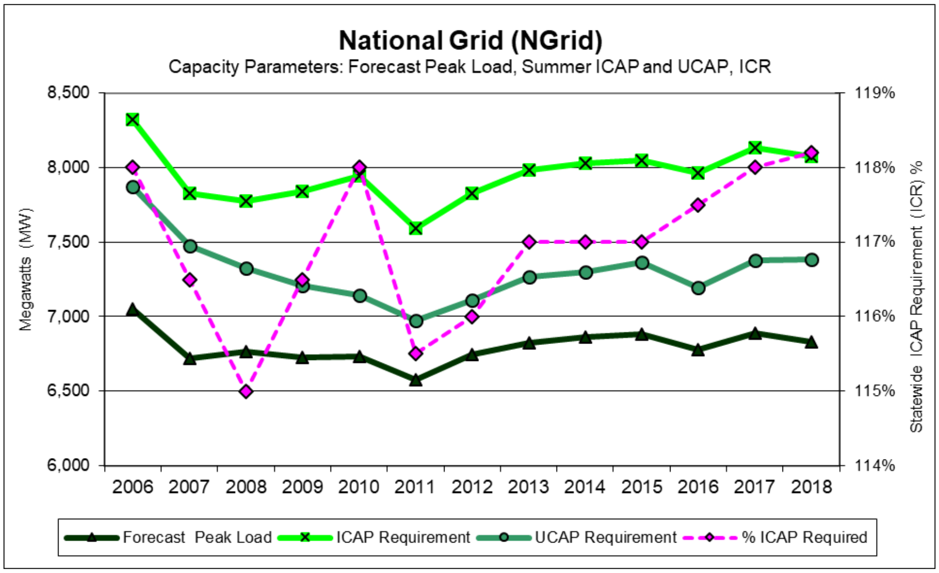
Year	Forecast Peak Load (MW)	ICAP Requirement (MW)	UCAP Requirement (MW)	%ICAP of Forecast Peak	%UCAP of Forecast Peak
2006	5,406.2	6,379.3	6,032.9	118.0%	111.6%
2007	5,321.8	6,199.9	5,923.4	116.5%	111.3%
2008	5,358.9	6,162.7	5,806.5	115.0%	108.4%
2009	5,431.7	6,327.9	5,821.1	116.5%	107.2%
2010	5,286.0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



C.2.4 National Grid (NGRID)

Table C.9 NGRID ICAP to UCAP Translation

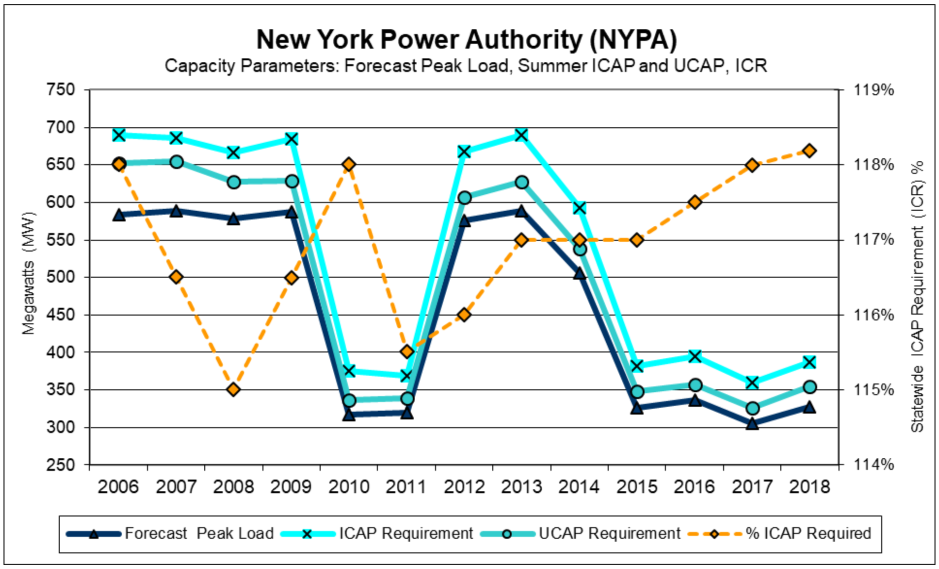
Year	Forecast Peak Load (MW)	ICAP Requirement (MW)	UCAP Requirement (MW)	%ICAP of Forecast Peak	%UCAP of Forecast Peak
2006	7,051.6	8,320.9	7,869.1	118.0%	111.6%
2007	6,718.6	7,827.2	7,478.1	116.5%	111.3%
2008	6,762.5	7,776.9	7,327.3	115.0%	108.4%
2009	6,728.4	7,838.6	7,210.7	116.5%	107.2%
2010	6,732.1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



C.2.5 New York Power Authority (NYPA)

Table C.10 NYPA ICAP to UCAP Translation

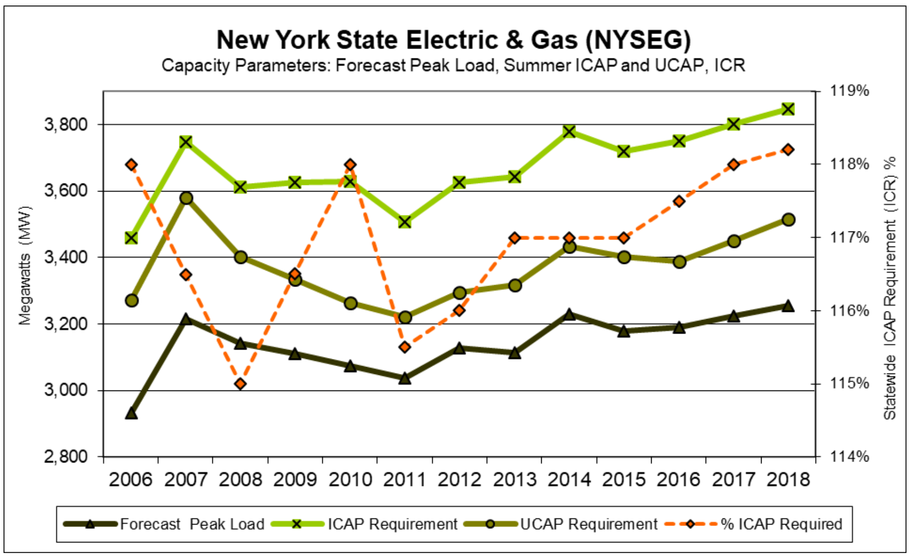
Year	Forecast Peak Load (MW)	ICAP Requirement (MW)	UCAP Requirement (MW)	%ICAP of Forecast Peak	%UCAP of Forecast Peak
2006	584.2	689.4	651.9	118.0%	111.6%
2007	588.2	685.3	654.7	116.5%	111.3%
2008	579.1	666.0	627.5	115.0%	108.4%
2009	587.2	684.1	629.3	116.5%	107.2%
2010	317.6	374.8	337.0	118.0%	106.1%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



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

Table C.11 NYSEG ICAP to UCAP Translation

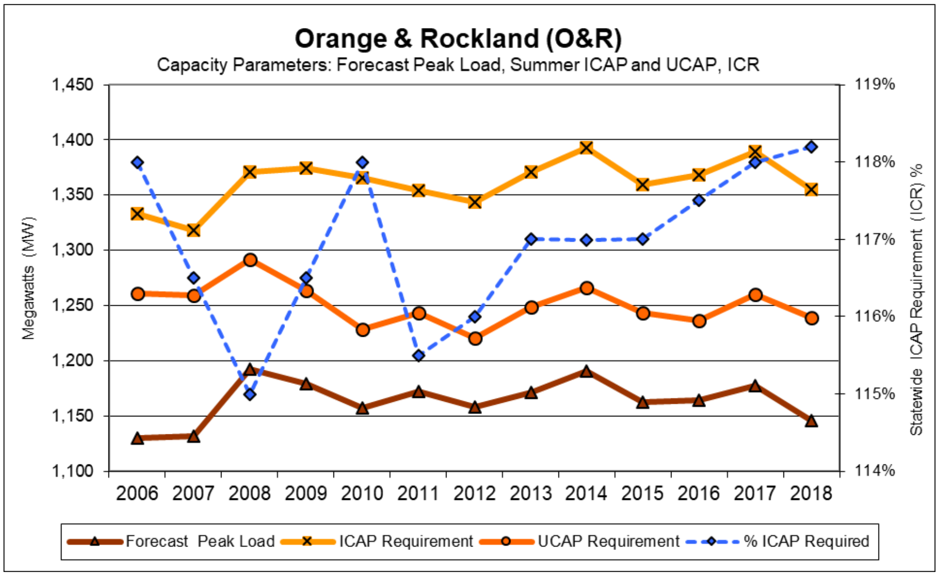
Year	Forecast Peak Load (MW)	ICAP Requirement (MW)	UCAP Requirement (MW)	%ICAP of Forecast Peak	%UCAP of Forecast Peak
2006	2,931.5	3,459.2	3,271.3	118.0%	111.6%
2007	3,216.9	3,747.7	3,580.5	116.5%	111.3%
2008	3,141.1	3,612.3	3,403.5	115.0%	108.4%
2009	3,111.8	3,625.3	3,334.9	116.5%	107.2%
2010	3,075.0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



C.2.7 Orange & Rockland (O & R)

Table C.12 O & R ICAP to UCAP Translation

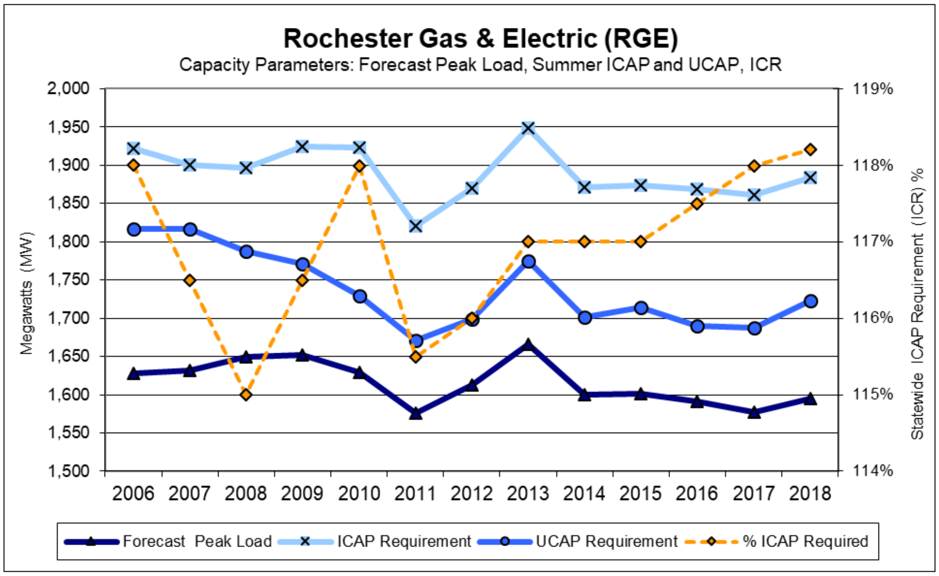
Year	Forecast Peak Load (MW)	ICAP Requirement (MW)	UCAP Requirement (MW)	%ICAP of Forecast Peak	%UCAP of Forecast Peak
2006	1,130.0	1,333.4	1,261.0	118.0%	111.6%
2007	1,131.5	1,318.2	1,259.4	116.5%	111.3%
2008	1,192.3	1,371.1	1,291.9	115.0%	108.4%
2009	1,179.5	1,374.1	1,264.0	116.5%	107.2%
2010	1,157.4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



C.2.8 Rochester Gas & Electric (RGE)

Table C.13 RGE ICAP to UCAP Translation

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



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

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

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

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

In general, effective wind capacity depends primarily on the availability of the wind. Wind farms in New York on average have annual capacity factors that are based on their nameplate ratings. A wind plant's output can range from close to nameplate under favorable wind conditions to zero when the wind 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 – 2013 through 2017 for this year's study, for new units the zonal hourly averages or averages for nearby units will be used. Wind shapes years are selected randomly from those years for each simulation year

Appendix D

Glossary of Terms

D. Glossary

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