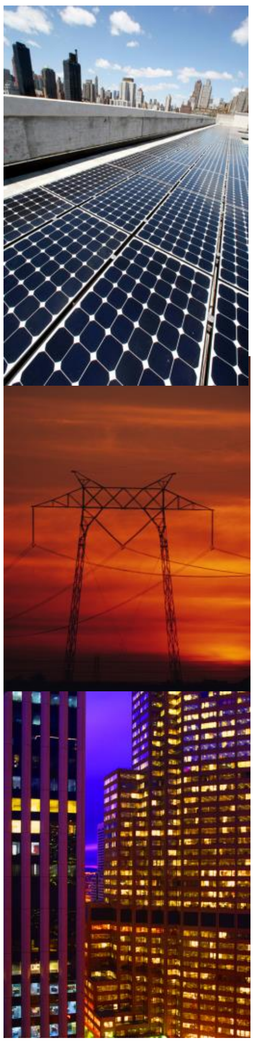
Appendices

New York Control Area Installed Capacity Requirement



For the Period May 2016 To April 2017

December 4, 2015

New York State Reliability Council, LLC
Installed Capacity Subcommittee

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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 in the Figure A.1 models, the source for the study assumptions, and where in Appendix A the assumptions are described. Finally, section A.3 compares the assumptions used in the 2015 and 2016 IRM reports.

Figure A.1 NYCA ICAP Modeling

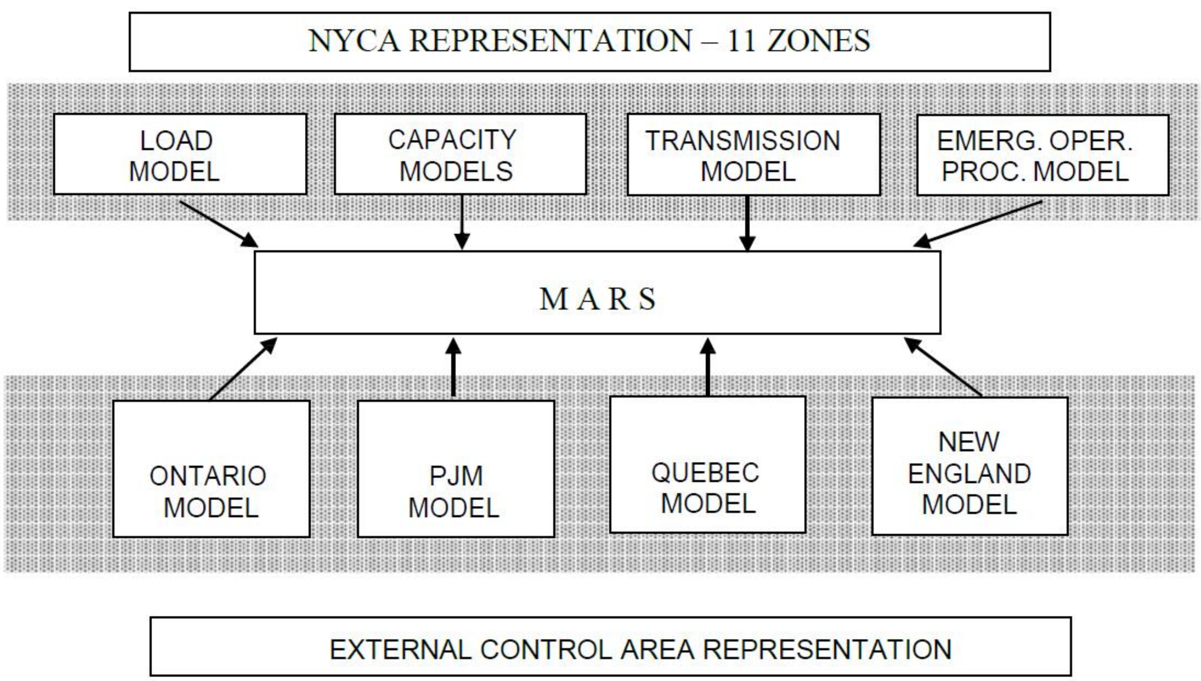


Table A.1 Modeling Details

#	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 2015 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] 2015 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 by the use of 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

$$Transition\ (1\ to\ 2) = \frac{(10\ Transitions)}{5{,}000\ Hours}$$
$$= 0.002$$

Table A.2 State Transition Rate Example

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

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

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

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

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

A.1.1 Error Analysis

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

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

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

For this analysis, the Base Case required 407 replications to converge to a standard error of 0.05 and required 1481 replications to converge to a standard error of 0.025. For our cases, the model was run to 1500 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 17.2% to 17.6%. It should be recognized that a 17.4% 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 3.18 of the GE-MARS software program. This is the same version that was used for the 2015 IRM study and 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 2016 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, as well as, the final locational capacity requirement. 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.
    - 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	2015 Study Assumption	2016 Study Assumption	Explanation
Peak Load	October 1, 2014 forecast NYCA: 33,587 MW NYC: 11,990 MW Long Island 5,522 MW GHIJ: 16,387	October 1, 2015 forecast NYCA: 33,378 MW NYC: 11,777 MW LI: 5,457 MW GHIJ: 16,375	Forecast based on examination of 2015 weather normalized peaks. Top three external Area peak days aligned with NYCA
Load Shape Model	Multiple Load Shapes Model using years **2002, 2006, and 2007**	Multiple Load Shapes Model using years **2002, 2006 and 2007**	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

(1) <u>Peak Load Forecast Methodology</u>

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 2015 to review analyses prepared by the NYISO and Transmission Owners of the weather response during the summer. Regional load growth factors (RLGFs) for 2016 were updated by each Transmission Owner based on projections provided to the LFTF in August 2015 by Moody's Analytics. The 2016 forecast was produced by applying the RLGFs to each TO's weather-normalized peak for the summer of 2015.

The results of the analysis are shown in Table A.4. The 2015 peak forecast was 33,567 MW. The actual peak of 31,076 MW (col. 2) occurred on July 29, 2015. After accounting for the impacts of weather and the demand response, the weather-adjusted peak load was determined to be 33,199 MW (col. 6), 370 MW (1.1%) below the forecast. The Regional Load Growth Factors are shown in column 9. The 2016 forecast for the NYCA is 33,378 MW (col. 10). The Locality forecasts are also reported in the second table below.

The LFTF recommends this forecast to the NYSRC for its use in the 2016 IRM study.

Table A.4 2016 Final NYCA Peak Load Forecast

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
Transmission District	2015 Actual MW	2015 Estimated SCR & Muni Self-Gen	SCR/EDRP Estimate MW	Weather Adjustment MW	2015 Weather Normalized MW	Loss Reallocation MW	2015 WN MW, Adj for Losses	Regional Load Growth Factors	2016 IRM Final Forecast
Central Hudson	1,048	0	0	71	1,119	-7	1,112	1.0020	1,114
Con Ed	12,050	0	0	1,437	13,487	166	13,653	1.0066	13,743
LIPA	5,136	0	0	249	5,385	53	5,438	1.0000	5,438
NGrid	6,931	0	0	61	6,992	-251	6,741	1.0060	6,782
NYPA	344	0	0	6	350	5	355	0.9951	353
NYSEG	3,041	0	0	97	3,138	8	3,146	1.0050	3,162
O&R	1,000	0	0	168	1,168	9	1,177	1.0161	1,196
RG&E	1,526	0	0	34	1,560	17	1,577	1.0080	1,590
Grand Total	31,076	0	0	2,123	33,199	0	33,199	1.0054	33,378

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
NYCA or Locality	2015 Actual MW	2015 Estimated SCR & Muni Self-Gen	SCR/EDRP Estimate MW	Weather Adjustment MW	2015 Weather Normalized MW	Regional Load Growth Factors	2016 IRM Final Forecast
Zone J - NYC	10,586		0	1,114	11,700	1.0066	11,777
Zone K - LI	5,235		0	222	5,457	1.0000	5,457
Zone GHIJ	14,730		0	1,532	16,262	1.0069	16,375

(2) Zonal Load Forecast Uncertainty

For 2016, updated models were provided by Con-Ed and LIPA for Zones H&I, J and K. The NYISO developed models for Zones A through G and reviewed the models for the other Zones. The results of these models are presented in Table A.4. Each row represents the probability that a given range of load levels will occur, on a per-unit basis, by Zone. These results are unchanged from last year and presented graphically in Figure A.2.

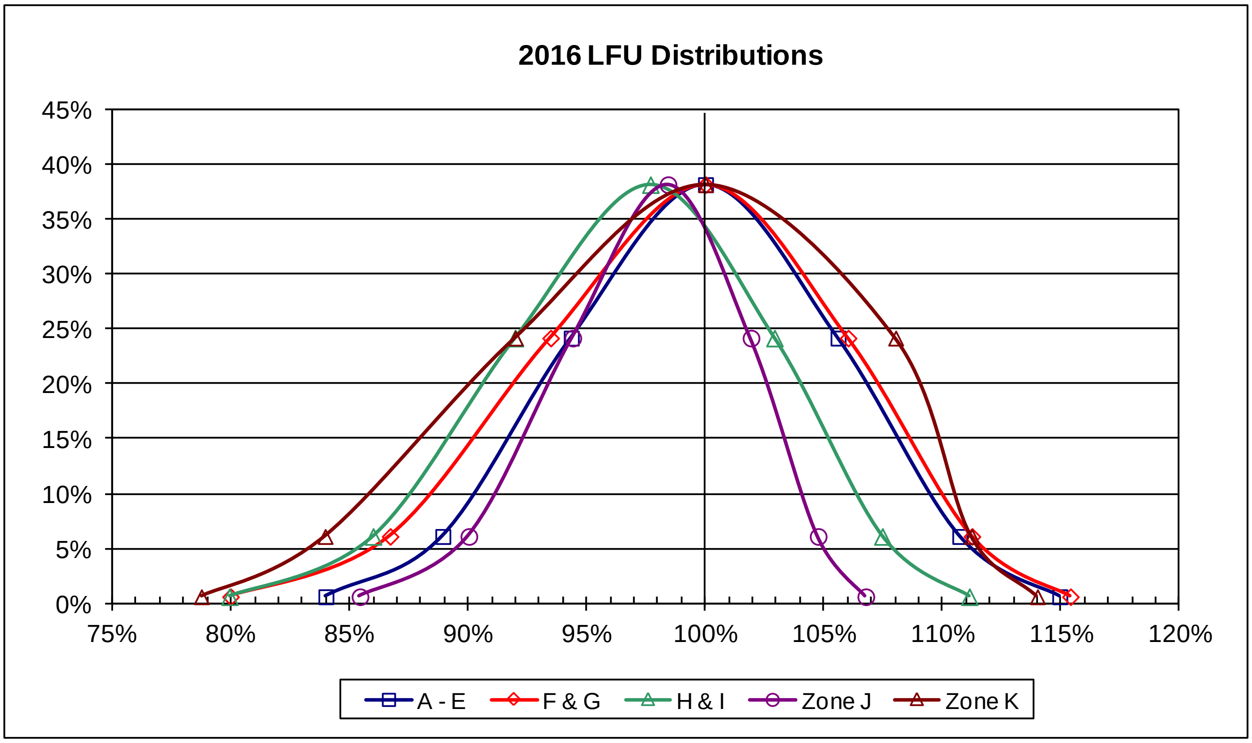
Table A.4 2016 Load Forecast Uncertainty Models

2016 Load Forecast Uncertainty Models

Bin No.	Probability	A - E	F&G	H & I	Zone J	Zone K
1	0.62%	83.99%	79.97%	79.92%	85.43%	78.74%
2	6.06%	88.92%	86.70%	85.98%	90.02%	83.96%
3	24.17%	94.34%	93.47%	91.97%	94.40%	91.98%
4	38.30%	100.00%	100.00%	97.68%	98.42%	100.00%
5	24.17%	105.59%	106.02%	102.91%	101.92%	108.02%
6	6.06%	110.73%	111.24%	107.46%	104.75%	111.23%
7	0.62%	114.94%	115.39%	111.13%	106.76%	114.00%

Low - Med	16.0%	20.0%	17.752%	13.0%	21.3%
Hi-Med	14.9%	15.4%	13.450%	8.3%	14.0%
Delta	30.9%	35.4%	31.202%	21.3%	35.3%

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 2016 LFU models have been reviewed by the NYISO Load Forecasting Task Force.

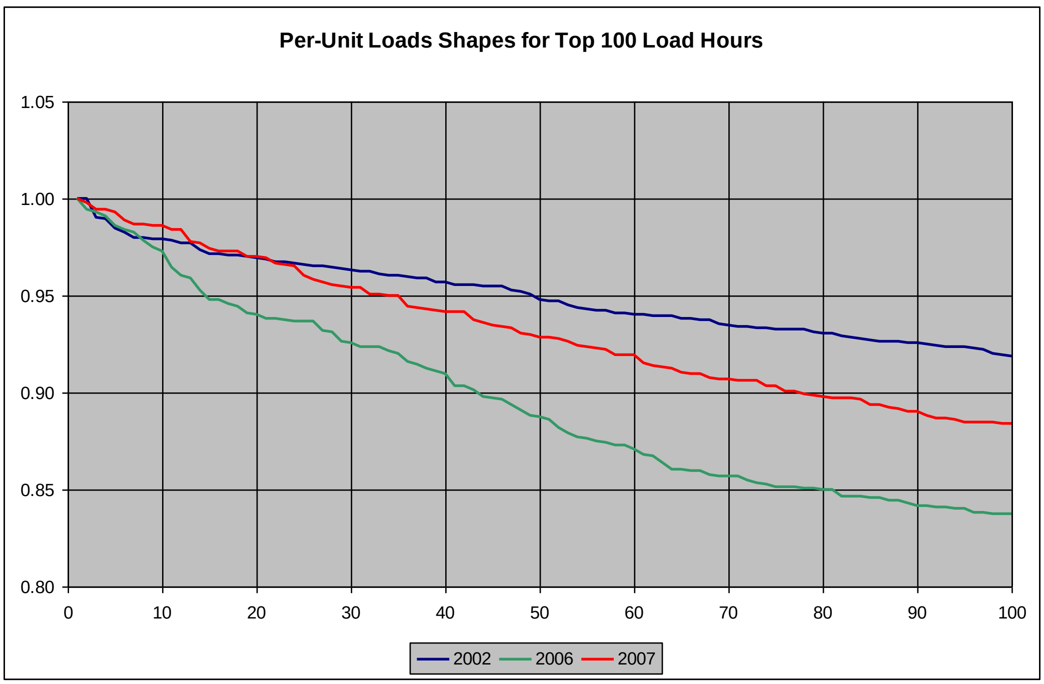
(3) Zonal Load Shape Models for Load Bins

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

2007 represents the load duration pattern of a typical year. The year 2002 represents the load duration pattern of many hours at high load levels. The year 2006 represents the load duration pattern of a heat wave, with a small number of hours at high load levels followed by a sharper decrease in per-unit values than the other two profiles.

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

Figure A.3 Per Unit Load Shapes



A.3.2 Capacity Model

The capacity model includes all NYCA generating units, including new and planned units, as well as units that are physically outside New York State, that have met specific criteria to offer capacity in the New York Control Area. The 2015 Load and Capacity Data Report is the primary data source for these resources. Table A.5 provides a summary of the capacity resource assumptions in the 2016 IRM study.

Table A.5 Capacity Resources

Parameter	2015 Study Assumption	2016 Study Assumption	Explanation
Generating Unit Capacities	2014 Gold Book values. Use min (DMNC vs. CRIS) capacity value	2015 Gold Book values. Use min (DMNC vs. CRIS) capacity value	2015 Gold Book publication
Planned Generator Units	743.0 MW of capacity was repowered or returned to service	374.4 MW of new non- wind resources	Unit rerate
Wind Resources	Wind Capacity – 1457.1 MWs	Wind Capacity - 1455.1 MWs. Same units as 2015. One unit rated 2 MWs lower.	Total Wind Modeled
Wind Shape	Actual hourly plant output of the 2013 calendar year. Summer Peak Hour availability of 14%	Actual hourly plant output of the 2013 calendar year. Summer Peak Hour availability of 14%	Production data from 2013
Solar Resources	Solar Capacity of 31.5 MW with a summer capacity factor of 47.3%.	31.5 MW of solar modeled per 2013 production data summer capacity factor of 38.8%.	Summer Peak capacity factor based on 2014 hourly production data June 1 – Aug 31, hours HB14 – HB18
Retirements and Mothballed units	111.7MW retirements reported	394.5 MW of retirements reported	Policy 5 guidelines on retirement or mothball disposition in IRM studies

Parameter	2015 Study Assumption	2016 Study Assumption	Explanation
Forced Outage Rates	Five-year (2009-2013) GADS data for each unit represented. Those units with less than five years – use representative data.	Five-year (2010 -2014) 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 (2010-2014)
Planned Outages	Based on schedules received by the NYISO and adjusted for history	Based on schedules received by the NYISO and adjusted for history	Updated schedules
Summer Maintenance	Nominal 50 MWs – divided equally between upstate and downstate	Nominal 50 MWs – divided equally between upstate and downstate	Review of most recent data
Gas Turbine Ambient Derate	Derate based on provided temperature correction curves.	Derate based on provided temperature correction curves.	Operational history indicates derates in line with manufacturer's curves
Small Hydro Derate	45% derate	46% derate	Review of historic production
Large Hydro	Probabilistic Model based on 30 years of operational data	Probabilistic Model based on 5 years of GADS data	Historical data submitted via GADS

(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 their nameplate, or full rated value, in the model. The 2015 NYCA Load and Capacity Report, issued by the NYISO, is the source of those generating units and their ratings included on the capacity model. The following units are being returned to service:

Bowline Unit 2 returned to full output Zone G a 374.4 MW increase to 557.4 MW

(2) Planned Generator Units

There were no new planned generator units scheduled to come on-line during the IRM 2016 study period.

(3) Wind Modeling

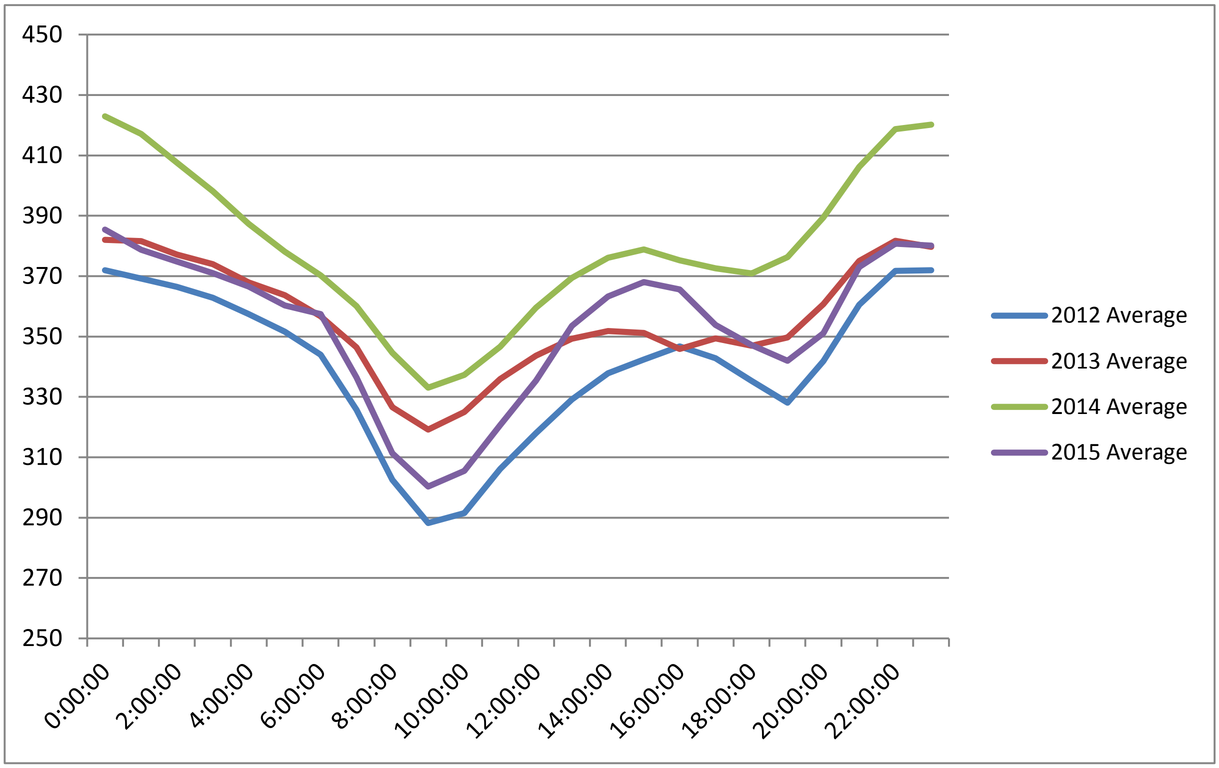
Wind generators are modeled as hourly load modifiers. The output of each unit varies between 0 MW and the nameplate value based on 2013 production data. Characteristics of this data indicate a capacity factor of approximately 14% during the summer peak hours. A total of 1455.1 MW of installed capacity associated with wind generators is included in this study.

Table A.6 Wind Generation

B3 - Wind Resources					
Wind Resouce	**Zone**	**In Service Date**	**CRIS (MW)**	**Summer Capability (MW)**	**MARS Model (MW)**
ICAP Participating Wind Units					
Altona Wind Power	D	09/23/2008	97.50	97.50	97.50
Bliss Wind Power	A	03/20/2008	100.50	100.50	100.50
Canandaigua Wind Power	C	12/05/2008	125.00	125.00	125.00
Chateaugay Wind Power	D	10/07/2008	106.50	106.50	106.50
Clinton Wind Power	D	04/09/2008	100.50	100.50	100.50
Ellenburg Wind Power	D	03/31/2008	81.00	81.00	81.00
Hardscrabble Wind	E	02/01/2011	74.00	74.00	74.00
High Sheldon Wind Farm	C	02/01/2009	112.50	112.50	112.50
Howard Wind	C	12/01/2011	57.40	55.40	55.40
Madison Wind Power	E	09/01/2000	11.50	11.60	11.50
Maple Ridge Wind 1	E	01/01/2006	231.00	231.00	231.00
Maple Ridge Wind 2	E	12/01/2007	90.70	90.80	90.70
Munnsville Wind Power	E	08/20/2007	34.50	34.50	34.50
Orangeville Wind Farm	C	12/01/2013	88.50	93.90	88.50
Steel Wind	A	01/23/2007	20.00	20.00	20.00
Wethersfield Wind Power	C	12/11/2008	126.00	126.00	126.00
		Totals	**1457.10**	**1460.70**	**1455.10**
Non - ICAP Participating Wind Units (Nameplate Capacity)					
Erie Wind		02/01/2012	0.00	15.00	0.00
Fenner Wind Farm		12/01/2001	0.00	30.00	0.00
Marble River		07/01/2012	0.00	215.50	0.00
Marsh Hill Energy Wind Farm		12/01/2014	0.00	16.20	0.00
Western NY Wind Power		10/01/2000	0.00	6.60	0.00
		Totals	0.00	283.30	0.00
Proposed IRM Study Wind Units					
		Totals	0.00	0.00	0.00
Total Wind Resources		**Totals**	1457.10	1744.00	**1455.10**

The present GE-MARS version allows only a single year wind shape to be input for the simulations. Over the last four years, the NYISO has collected hourly wind generation output. The GE MARS model has been enhanced to use multiple years of wind in the simulations. This feature will be tested for use in the 2017 IRM study. Figure A-4 illustrates the average annual wind output by year for 2012 through 2015. As noted above, Year 2013 hourly wind production was used in the 2016 IRM study.

Figure A.4 Average Annual Wind Generation Hourly Shapes



(4) Solar Modeling

Solar generators are modeled as hourly load modifiers. The output of each unit varies between 0 MW and the nameplate MW value based on 2014 production data. Characteristics of this data indicate an overall 38.8% capacity factor during the summer peak hours. A total of 31.5 MW of solar capacity was modeled in Zone K.

(5) Retirements

Huntley (394.5 CRIS MW) had announced its intent to retire, but the NYISO had not completed its reliability analysis by the time the final base was approved. Subsequent to the finalization of the base case, the NYISO completed its reliability analysis and determined the retirement could proceed with the addition of transmission upgrades that would resolve potential violations of reliability criteria. The model reflecting the announced retirement of the Huntley units was adopted as the base case.

(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 2016 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 majority of the NYCA units were obtained from the five-year NERC.GADS outage data collected by the NYISO for the years 2010 through 2014. 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.5 NYCA Annual Zonal EFORds

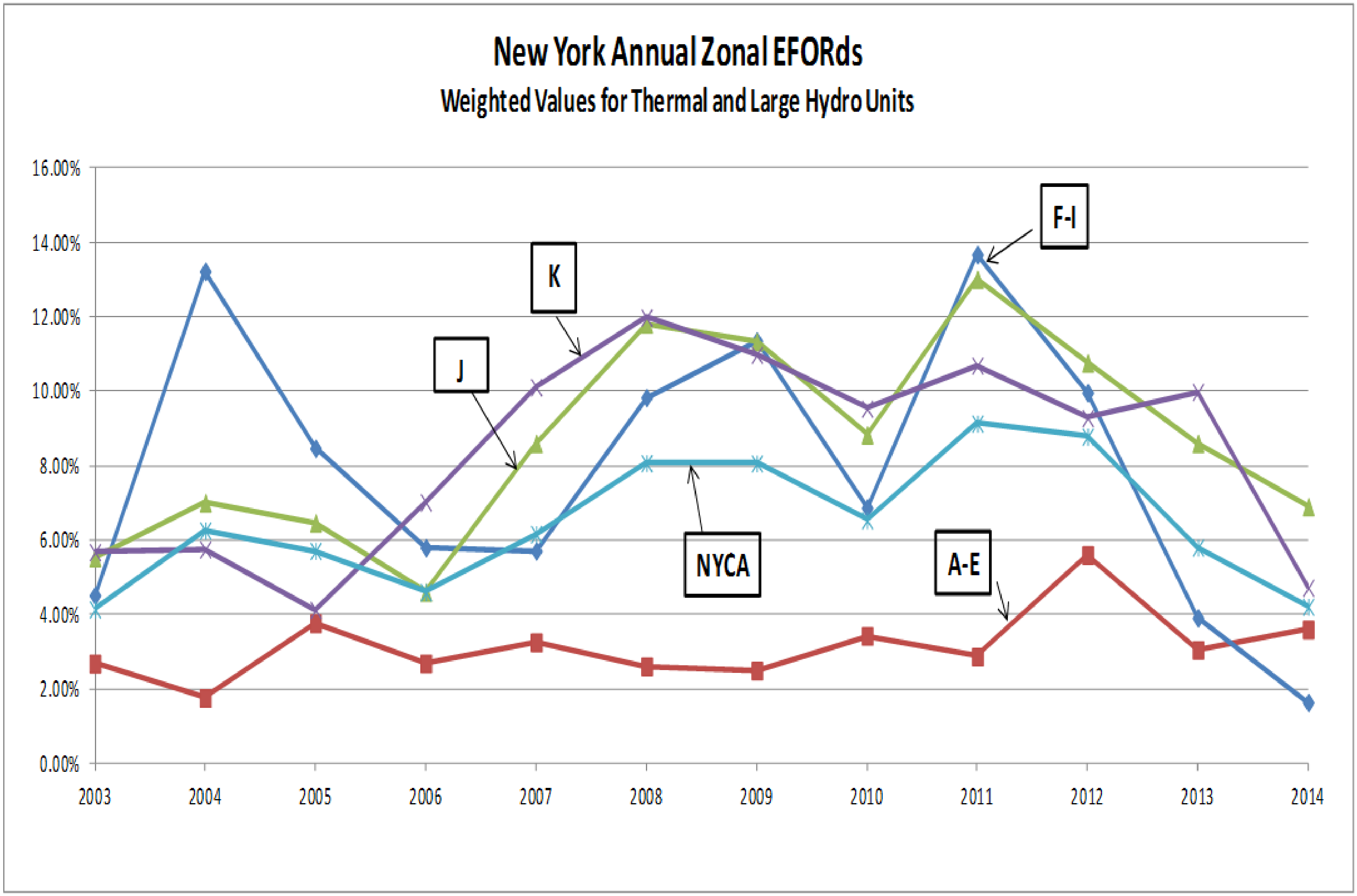


Figure A.6 Five-Year Zonal EFORds

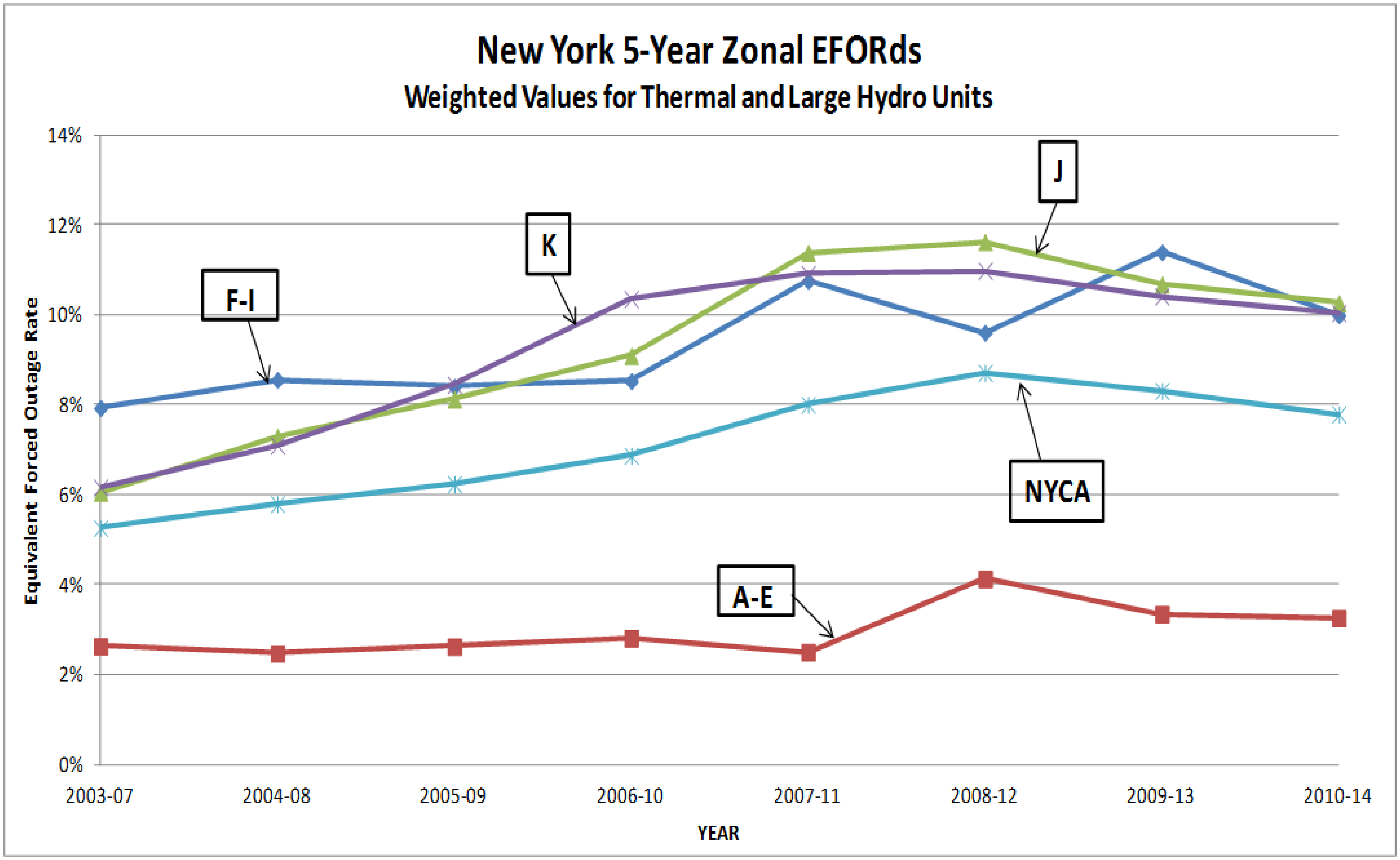


Figure A.7 NYCA Annual Availability by Fuel

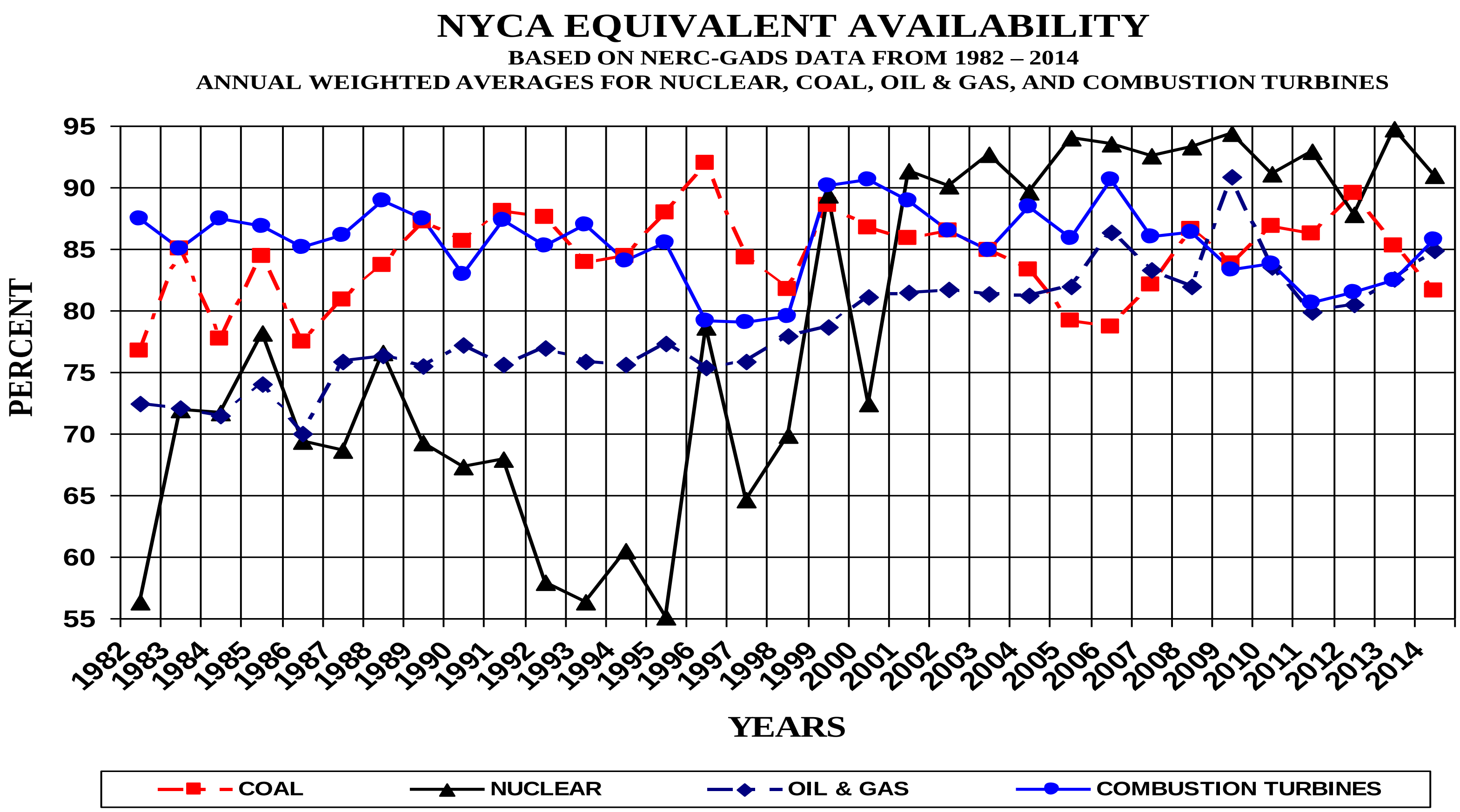


Figure A.8 NYCA Five-Year Availability by Fuel

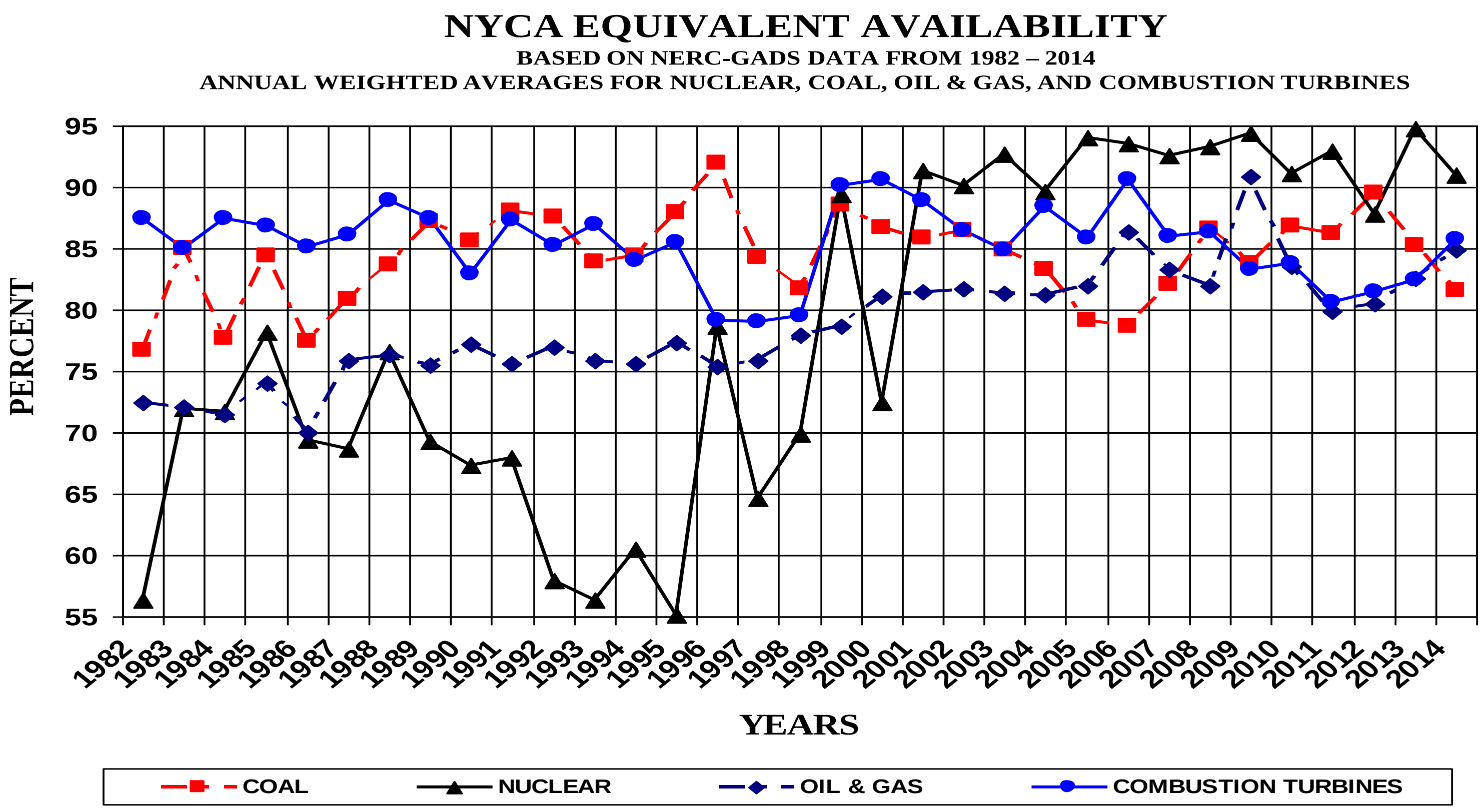


Figure A.9 NERC Annual Availability by Fuel

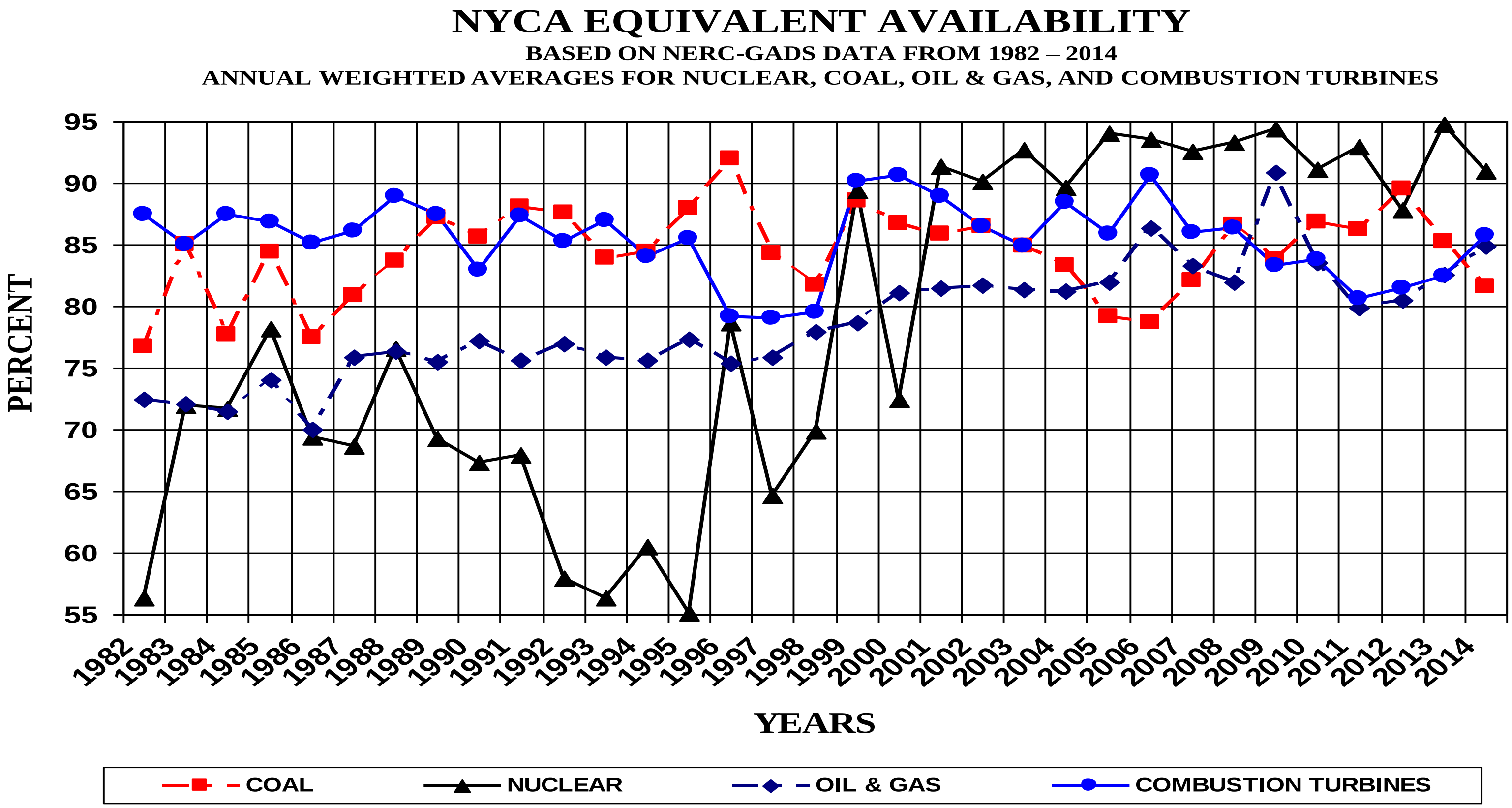
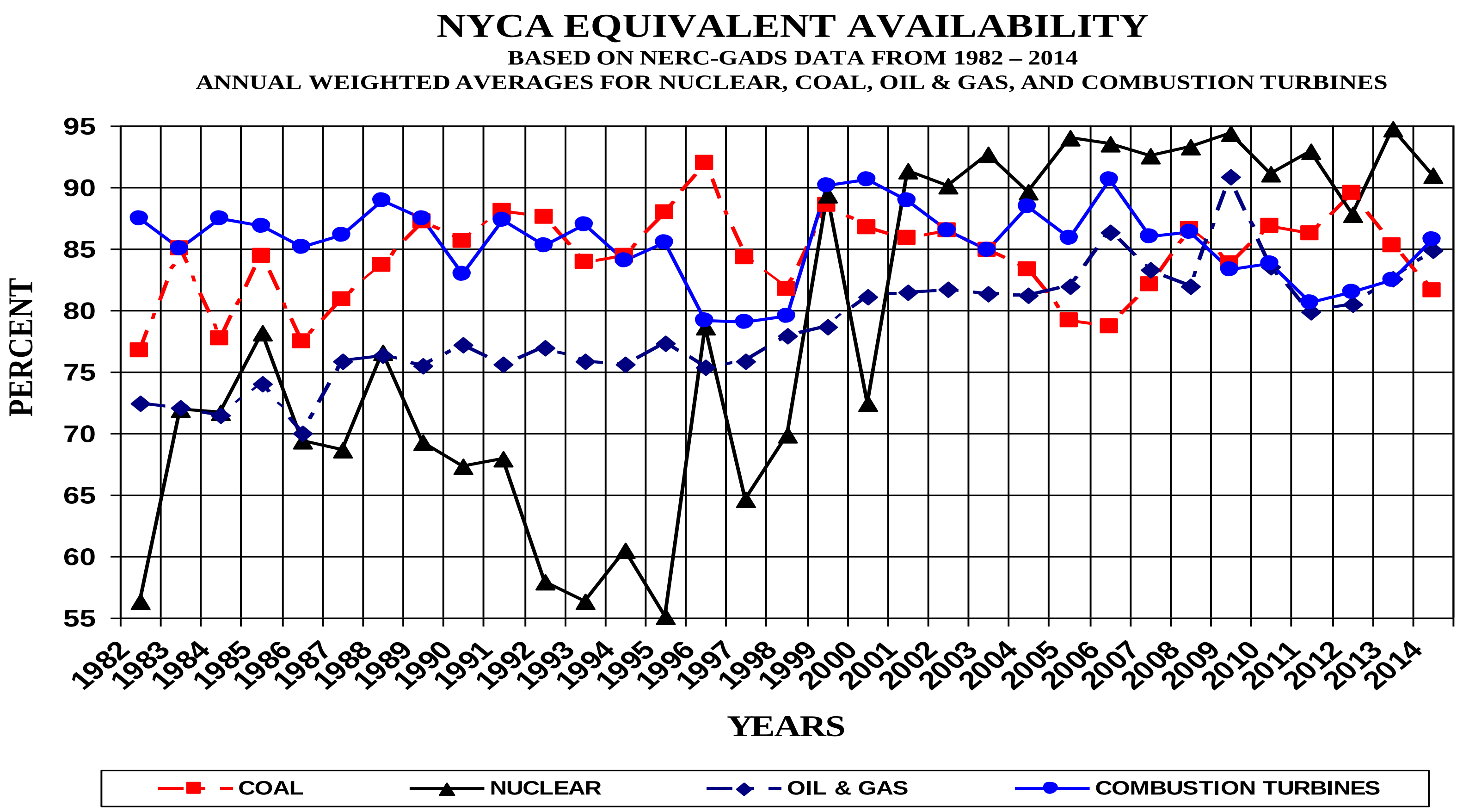


Figure A.10 NERC Five-Year Availability by Fuel



(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, and where necessary, extended so that the scheduled maintenance outage (MO) period equals the historic average using the same five-year period used to determine EFORd averages. Figure A.10 provides a graph of scheduled outage trends over the 1992 through 2014 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 five-year period is reviewed to determine the scheduled maintenance MW during the previous peak periods. An assumption is determined as to how much to model in the current study. For the 2016 IRM Study, a nominal 50 MW of summer maintenance is modeled. The amount is equally divided between upstate and downstate. Figure A.11 shows the weekly scheduled maintenance for the 2015 IRM Study compared to this study.

(8) Gas Turbine Ambient Derate

Operation of combustion turbine units at temperatures above DMNC test temperature results in reduction in output. These reductions in *g*as turbine and combined cycle capacity output are captured in the GE-MARS model using deratings based on ambient temperature correction curves. Based on its review of historical 2006 and 2007 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.

A NYISO report on this analysis, "*Adjusting for the Overstatement of the Availability of the Combustion Turbine Capacity in Resource Adequacy Studies*", dated October 22, 2007, can be found on the NYISO web site.

The derate does not affect all units because there are units capable of generating up to 88 or 94 MW but are limited by permit to 79.9 MW, so these units are not impacted by the temperature derating in obtaining an output of 79.9 MW. About one quarter of the existing 3,700 MW of simple cycle Combustion Turbines fall into this category. The accuracy of temperature corrections for all combustion turbines will continue to be evaluated as operational data becomes available.

(9) Large Hydro Derates

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

Figure A.4 Planned and Maintenance Outage Rates

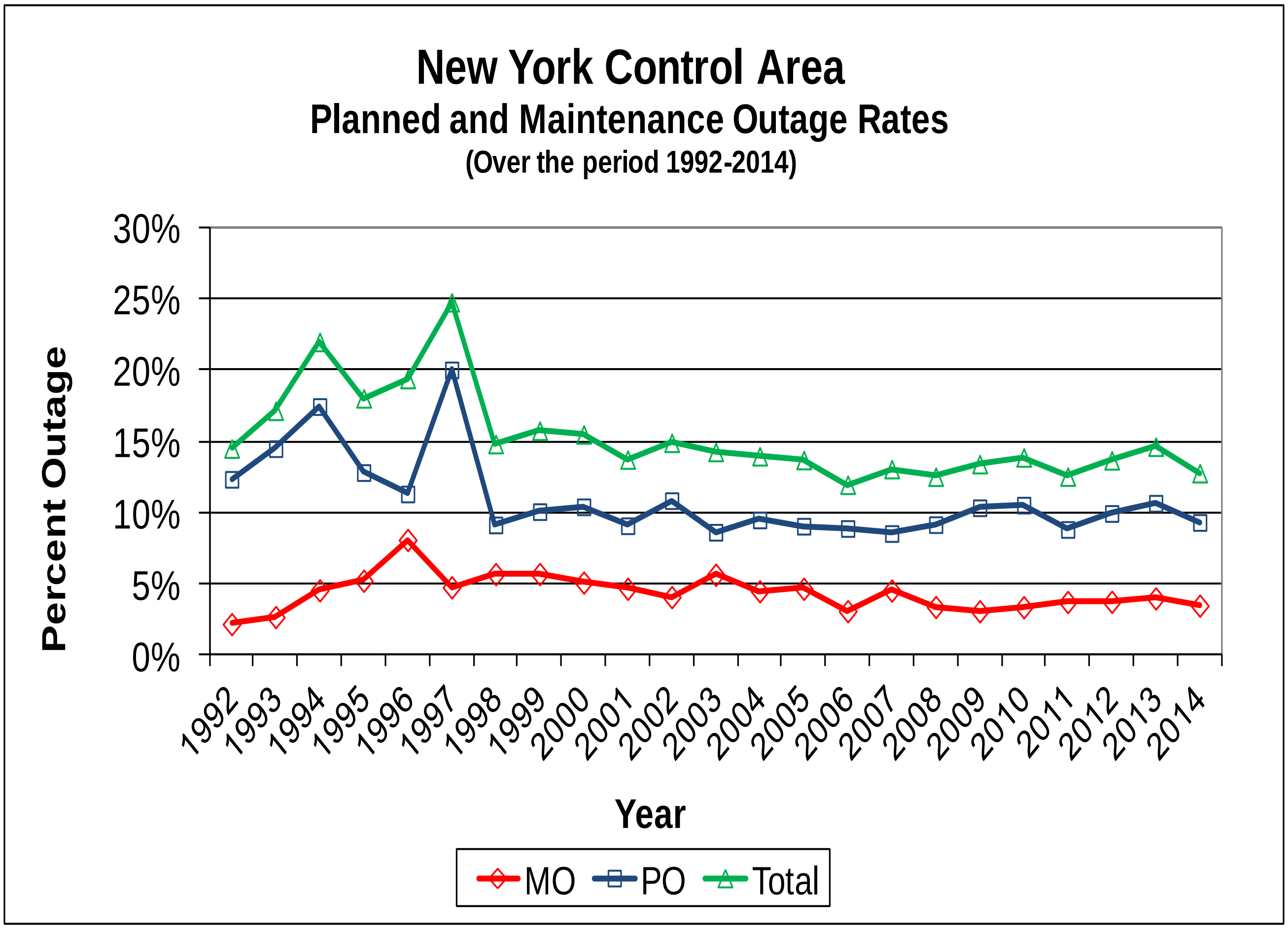
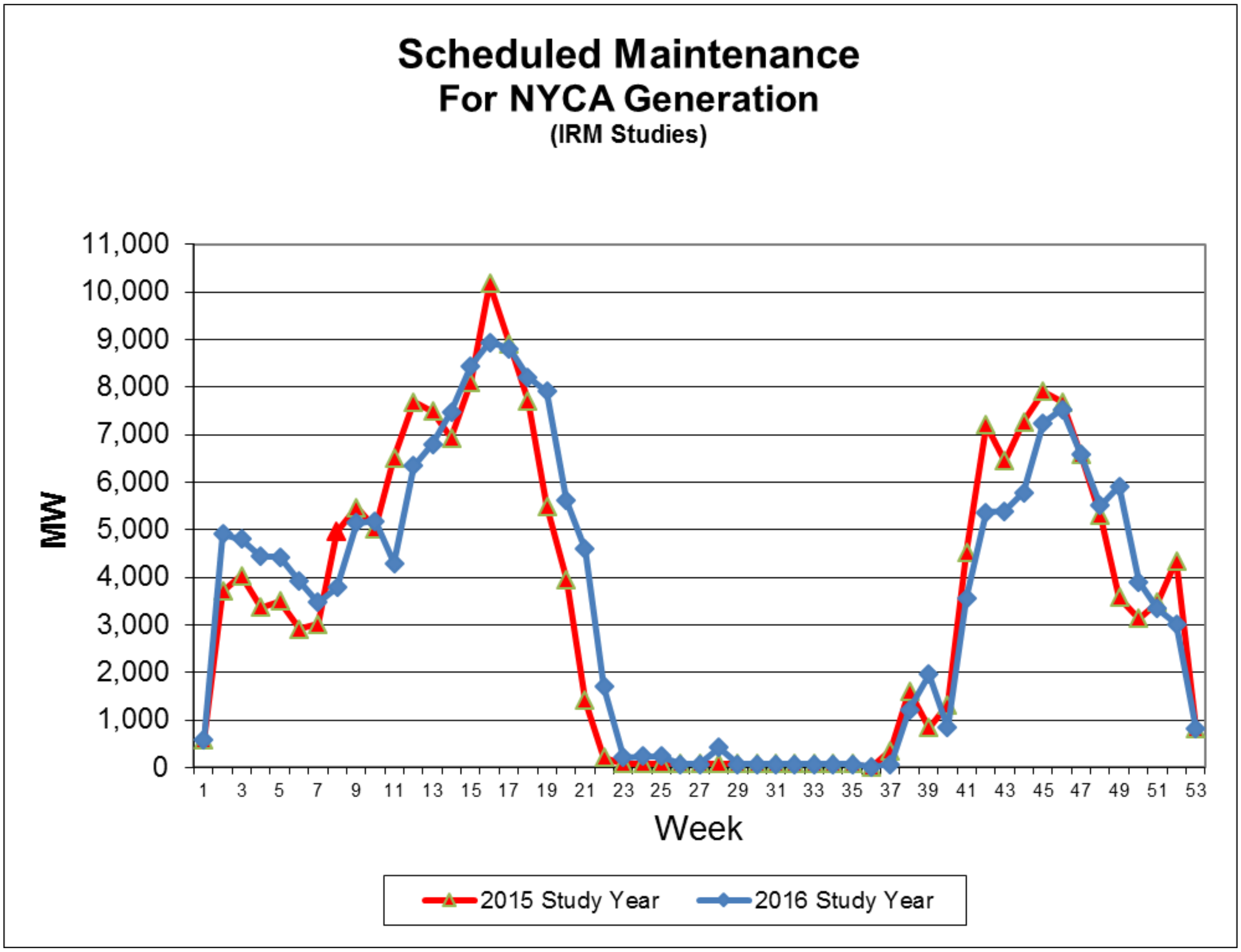


Figure A.5 Scheduled Maintenance



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.13. The transfer limits employed for the 2016 IRM Study were developed from emergency transfer limit analysis included in various studies performed by the NYISO, based upon input from Transmission Owners and neighboring regions. The transfer limits are further refined by assessments conducted for this IRM study. The assumptions for the transmission model included in the 2016 IRM study are listed in Table A.7.

Forced transmission outages are included in the GE-MARS model for the underground cables that connect New York City and Long Island to surrounding Zones. The GE-MARS model uses transition rates between operating states for each interface, which were calculated based on the probability of occurrence from the failure rate and the time to repair. Transition rates into the different operating states for each interface are 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 particular cable.

The TOs provided updated transition rates.

The interface transfer limits were updated for the 2016 IRM Study model based on transfer limit analysis performed for the 2015 Reliability Needs Assessment

Table A.7 Transmission System Model

Parameter	2015 Model Assumptions	2016 Model Assumptions Recommended	Basis for Recommendation
Interface Limits	All changes reviewed and commented on by TPAS	All changes reviewed and commented on by TPAS	Based on 2015 Operating Study, 2015 Operations Engineering Voltage Studies, 2014 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 will be updated for NYC and LI to reflect most recent five-year history	Based on TO analysis
New UDRs	No new UDRs	No new UDR projects	Existing UDR elections are made by August 1st and were incorporated into the model

Figure A.13 shows the transmission system representation for this year's study. Figure A.14 shows a more detailed representation of the interconnections surrounding the PJM/NYCA downstate interface. Finally, Figure A.15 shows the 13 zone New England Representation in more detail.

As can be seen from the figures, the changes made to interface limits are as follows:

Table A.8 Interface Limits Updates

	2015		2016		Delta	
Interface	**Forward**	**Reverse**	**Forward**	**Reverse**	**Forward**	**Reverse**
Dysinger East	2200/1575/950		1650		-550	
Zone A Group	2300/1550/775		1800		-500	
West Central	1300		1300			
Volney East	5650		5650			
Moses South	2650		2650			
Central East	3250		3100		-100	
Central East Group	4800/4725/4640/ 4485/4310	3400	5000/4925/4840 /4685/4510	3400	+200/+200/+200/ +200/+200	
Marcy South	1700	1600	1700	1600		
UPNY-SENY	5150		5600		+450	
UP_CONED	5210		5210			
Millwood	8450		8450			
Dunwoodie	4400		4400			
Zone F to G	3475		3475			
LILCO	235	510	235	490		-20
LI Sum	1525	297/260/ 144	1528	282/202/ 29	+3	-15/-52/ -115
I to K	1290	530	1293	490	+3	-40
A Line + VFT	815/700/500/200		815/700/500/200			
PJM-SENY Group	3075		2000		-1075	

In the 2015 IRM study, Dysinger East and Zone A group interfaces limits varied depending upon the number of Dunkirk and Huntley units out of service, with the lowest transfer effective when four units were out of service. In this year's study, with the Dunkirk units in a mothballed state and the Huntley units retired, the nomogram is no longer needed. While the Dysinger East and Zone A Group maximum transfer limits decreased because of the retirement of the Huntley units compared to the transfer limit used in the 2015 IRM, it increased from the lowest transfer limit due to the transmission upgrades on the National Grid system.

A PJM-SENY group limit was imposed to reflect internal constraints in both PJM and NY systems, and was restored to the topology and transfer limits similar to 2014

IRM Study topology. The changes were made to reflect: 1) the balance of the ConEd-PSEG wheel[2], and 2) the delay of the assumed Northern NJ transmission upgrades and the potential delay of the Phase II (additional cooling) of Staten Island Unbottling project Central East, Central East Group, and UPNY-SENY interface transfer limits were updated to reflect the additional transmission facilities. Portions of the Transmission Owner Transmission Solutions (TOTS) are expected to be in-service before summer 2016: Marcy South Series Compensation, an additional 345 kV circuit between Rock Tavern and Ramapo, and a 345/138 kV tap connecting to the existing Sugarloaf 138 kV station.

[2] Per NYISO OATT 35.22 Attachment CC Schedule C, the NYISO model allows for delivery of 1,000 MW at Waldwick and PJM re-delivery of 1,000 MW at the Hudson and Linden interface. The balancing of the wheel was adjusted to reflect the actual thermal capability of the Hudson and Linden interface.

Figure A.13 2016 Transmission Representation

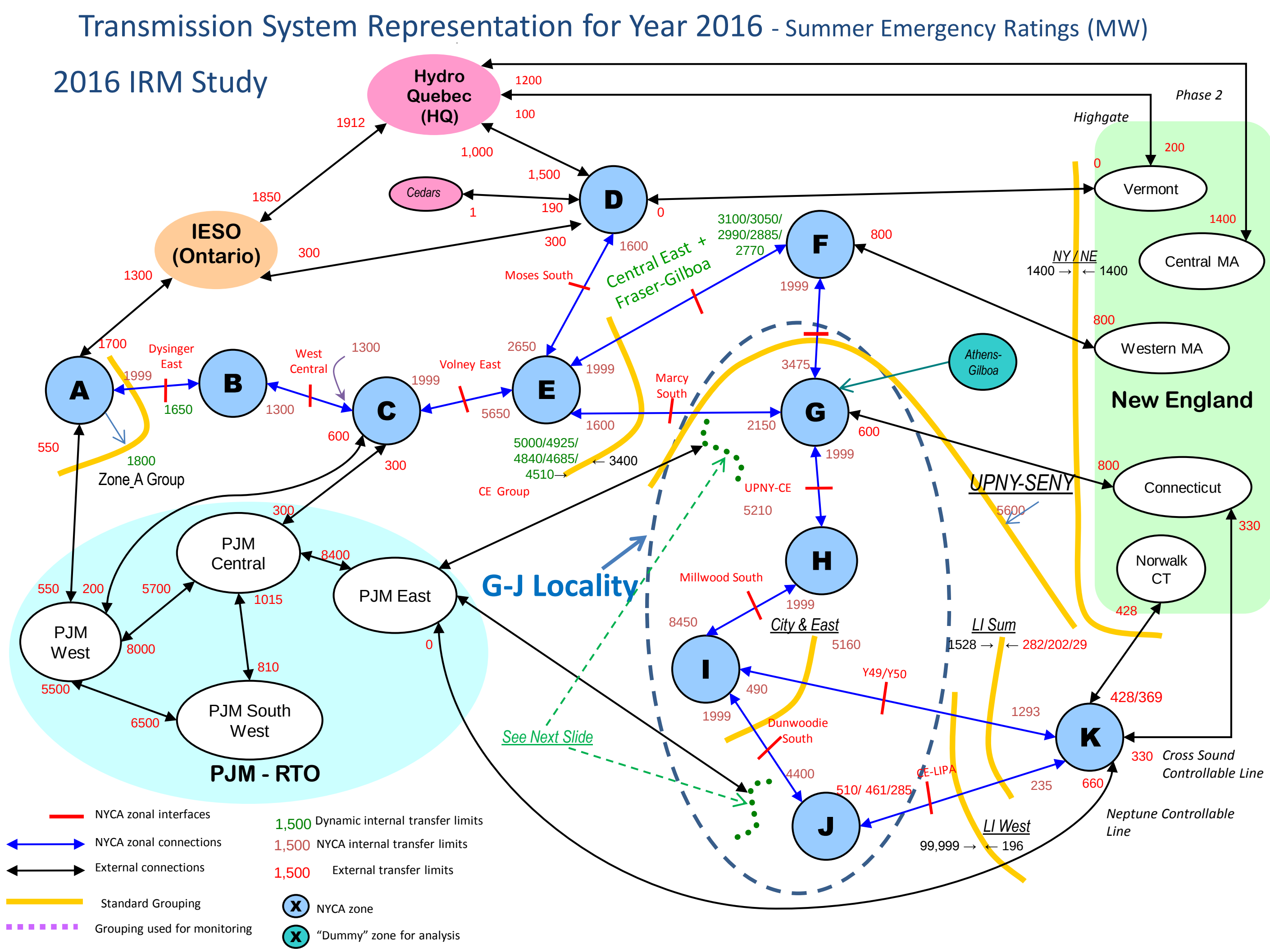


Figure A.14 PJM – SENY Interface Model

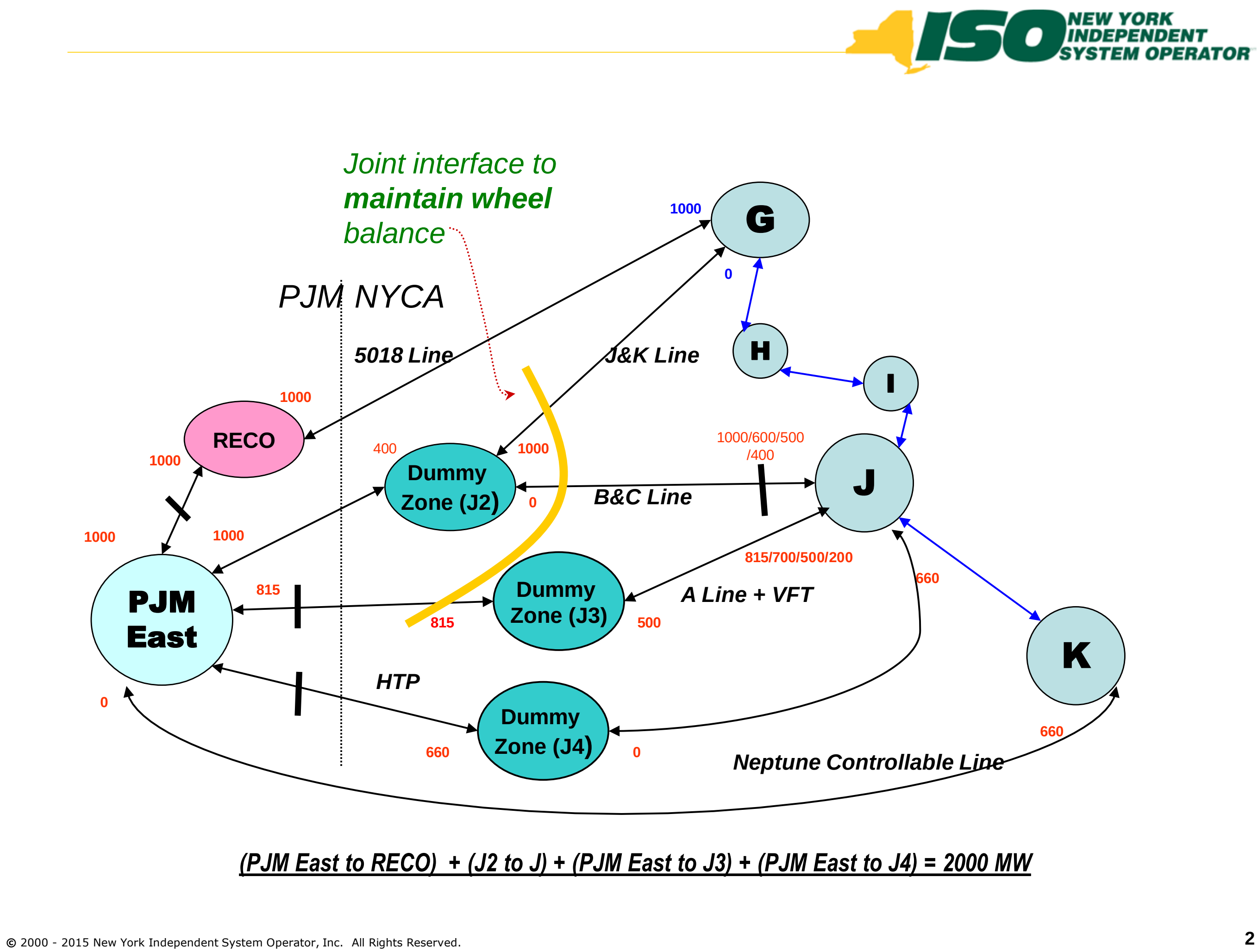
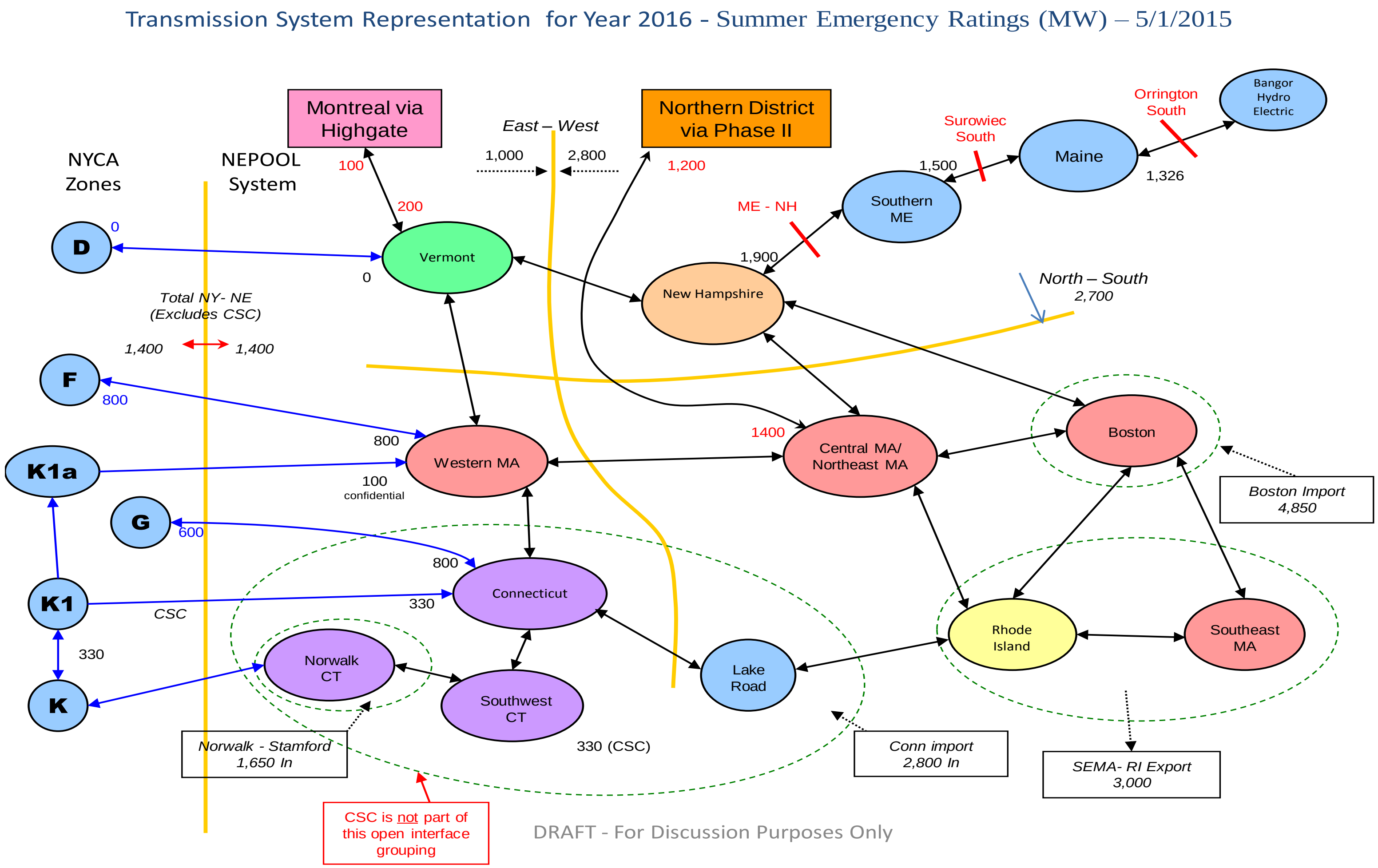


Figure A.15 Full New England Representation



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 purpose, rules are applied whereby; 1) an external Control Area's LOLE cannot be lower than its LOLE criteria, 2) its isolated LOLE cannot be lower than that of the NYCA, 3) 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.

In order to avoid over-dependence from emergency assistance, the three highest summer load peak days of the external Control Areas' are modeled to match the same load sequence as NYCA.

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 5-9 is as follows:

Table A.9 External Area Representations

Parameter	2015 Study Assumption	2016 Study Assumption	Explanation
Capacity Purchases	Grandfathered amounts: PJM – 1080 MW HQ – 1090 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. HQ increase due to 20 MW CRIS application
Capacity Sales	Long term firm sales of 281.8 MW	Long term firm sales of 286.6 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. Four 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.11, below, shows the final reserve margins and LOLEs for the Control Areas external to NYCA.

Table A.10 Outside World Reserve Margins

Area	2015 Study Reserve Margin	2016 Study Reserve Margin	2015 Study LOLE (Days/Year)	2016 Study LOLE (Days/Year)
Quebec	40.9%*	38.6%*	0.105	0.104
Ontario	6.2%	34.2%**	0.104	0.112
PJM-Mid-Atlantic	15.0%	11.9%	0.234	0.147
New England	13.8%	15.5%	0.106	0.136

*This is the summer margin.

**This includes 4242 MW full capacity of wind units.

A.3.5 Emergency Operating Procedures (EOPs)

There are many steps that the system operator can take in an emergency to avoid disconnecting load. EOP steps 2 through 10 listed in Table A.12 were provided by the NYISO based on operator experience. Table A.11 lists the assumptions modeled.

The values in Table A.11 are based on a NYISO forecast that incorporates 2015 operating results. This forecast is applied against a 2016 peak load forecast of 33,378 MW. The table shows the most likely order that these steps will be initiated. The actual order will depend on the type of the emergency. The amount of assistance that is provided by EOPs related to load, such as voltage reduction, will vary with the load level.

Table A.11 Assumptions for Emergency Operating Procedures

Parameter	2015 Study Assumption	2016 Study Assumption	Explanation
Special Case Resources	July 2014 – 1132.4 MW based on registrations and modeled as 742.1 MW. Monthly variation based on historical experience (no limit on the number of calls)	July 2015 –1254 MW based on registrations and modeled as 961 MW of effective capacity. Monthly variation based on historical experience (no Limit on number of calls)*	Those sold for the program, discounted to historic availability.
EDRP Resources	July 2014 – 86 MW registered; modeled as 14 MW in July and Aug and proportional to monthly peak load in other months. Limit to 5 calls per month	July 2015 75 MW registered modeled as 12 MW in July and proportional to monthly peak load in other months. Limit to five calls per month	Those registered for the program, discounted to historic availability. Summer values calculated from July 2015 registrations.
EOP Procedures	713 MW of non-SCR/EDRP MWs	671 MW of non-SCR/non-EDRP resources	Based on TO information, measured data, and NYISO forecasts

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

Table A.12 Emergency Operating Procedures Values

Parameter	Procedure	Effect	MW Value
1	Special Case Resources (SCRs)	Load relief	1254 MW Enrolled/961 MW modeled
2	Emergency Demand Response Programs (EDRPs).	Load relief	75 MW Enrolled/12 MW Modeled
3	5% manual voltage reduction***	Load relief	65 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	376 MW
6	Voluntary industrial curtailment***	Load relief	142 MW
7	General public appeals***	Load relief	88 MW
8	Emergency Purchases	Load relief	Varies
9	Ten-minute reserve to zero	Allow 10-minute reserve to decrease to zero	1310 MW
10	Customer disconnections	Load relief	As needed

** The SCR's are modeled as monthly values. The value for July is 1253.9 MW.*
*** The EDRPs are modeled as 75 MW discounted to 12 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 2016peak load of 33,378 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 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 two transmission-constrained Zones, New York City and Long Island, and are normally expressed as a percentage of each Zone's annual peak load.

These locational ICAP requirements, recognized by NYSRC Reliability Rule A.R2 and monitored by the NYISO, supplement the statewide IRM requirement. This report using the unified methodology determines the minimum locational requirements for different levels of installed reserve. The NYSRC chooses the IRM to be used for the coming year and the NYISO chooses the final value of the locational requirements to be met by the LSEs.

A.3.7 Special Case Resources and Emergency Demand Response Program

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

Table A.13 SCR Performance

Zones	Forecast SCRs (MW)	Overall Performance (%)
A - F	719.1	80.0
G - I	80.6	75.1
J	386.1	71.9
K	68.1	69.4

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 models SCRs and EDRPs as EOP steps and will activate these steps to minimize the probability of customer load disconnection. Both GE-MARS and NYISO operations only activate EOPs in zones where they are capable of being delivered.

SCRs are modeled with monthly values. For the month of July, the value is 1253.9 MW. This value is the result of applying historic growth rates to the latest participation numbers.

EDRPs are modeled as a 12 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 75 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 correct as is, or institutes a correction. The results of this data scrub are shown in Table A.14.

Table A.14 GE MARS Data Scrub

Item	Description	Disposition	Data Change	Effect on IRM
1	24 Units have EFORds greater than 50% versus 16 Units last year.	Data was examined and determined valid. This grouping o f units had the lowest average MW output	No	No
2	65 Units have EFORds between 30% and 50% versus 29 Units last year.	Data was examined and determined valid. Again, these were small units. All other groupings had reductions in EOFRds	No	No
3	15 smaller units had EFORd of zero.	Data was examined and determined valid. This statistic will be tracked going forward.	No	No
4	A zonal comparison of EFORds showed similar values from last year to this year with the exception of zone E, in which EFORds increased.	Certain units had EFORds accounted for in a different manner last year and were not calculated as part of the 07 output. The previous calculation compared well to this year for zone E.	No	No
5	Zonal MWs fell moderately for zones C, E, F, and G	All units were identified with lower tested output	No	No

A.4.2 NYISO Data Scrub

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

Table A.15 NYISO MARS Data Scrub

Item	Description	Disposition	Data Change	Effect on IRM
1	**Generation:** Units BINGCG and AST2 had incorrect installment dates.	Corrected in the parametric study cases before the preliminary base case.	Yes	No
2	**Load:** Dummy bubble F1 had NCP input other than 0.001 MW.	Corrected in the parametric study cases before the preliminary base case.	Yes	No
3	**Transfer Limits:** Redundant definition caused NYCA/ISO-NE interface group limits being overwritten to zero.	Corrected in the parametric study cases before the preliminary base case.	Yes	Yes
4	**Transition Rate:** DUNWOODI cable had entry typos at (Row 1, Column 8), (Row 2, Column 7), and (Row 2, Column 8). J_WHEEL, J_VFT, and J_HTP cables all had entry typos at (Row 5, Column 6).	Corrected in the parametric study cases before the preliminary base case.	Yes	No
5	**Wind Shape:** 2014 wind shape's production showed an out of order increase in performance compared historic data.	The wind shapes from the 2013 production data were kept for the preliminary and final base case. A sensitivity was performed using multiple years of wind production data.	Yes	Yes
6	**Topology:** The capacity flow wheel from Zone G to Zone J through PJM was not balanced.	After the preliminary base case, a joint interface has been defined to maintain flow balance of the wheel for the final base case.	Yes	Yes
7	**Transfer Limits:** Transmission projects in PJM that were slated for completion this summer have slipped in schedule to 2018. The PJM to SENY transfer capability was restored to the values used before these projects.	After the preliminary base case, interface ratings were returned to values found before the upgrades.	Yes	Yes

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. Table A.16 shows these results.

Table A.16 Transmission Owner Data Scrub

Item	Description	Disposition	Data Change	Effect on IRM
1	**Transfer Limits:** The interface reverse limit of Y49Y50 should be 490 MW, but it was 530 MW in the model.	Corrected in the preliminary base case.	Yes	No
2	**Transfer Limits:** The interface limit of PJMW_C was 7500 MW in topology diagram, but is 8000 MW in the model.	The data in the model is correct. The topology diagram has been updated.	No	No
3	**Transfer Limits:** The interface limit of HQ-VT should be 200 MW, but it was 250 MW in the model.	Corrected in the preliminary base case.	Yes	No
4	**Load:** The zonal peak load values were not present in current input file thus unable to verify.	The zonal peak load values are presented and can be verified in ot07 and ot09 output files.	No	No
5	**EOP:** EDRP was off by 1 MW. It should be 12 MW but it was 10.76 MW in the model.	Corrected in the preliminary base case.	Yes	No

Appendix B

Details of Study Results

B. Details for Study Results

B.1 Sensitivity Results

Table B.1 summarizes the 2016 Capability Year IRM requirements under a range of assumption changes from those used for the base case. The base case utilized the computer simulation, reliability model, and assumptions described in Appendix A. The sensitivity cases determined the extent of how the base case required IRM would change for assumption modifications, either one at a time, or in combination. The methodology used to conduct the sensitivity cases was to start with the preliminary base case 16.8% IRM results then add or remove capacity from all zones in NYCA until the NYCA LOLE approached criteria. The values in Table B.1 are the sensitivity results adjusted to the 17.4% final base.

Table B.1 Sensitivity Case Results

Case	Description	IRM (%)	NYC (%)	LI (%)
0	**Final Base Case**	17.4	80.8	102.4
	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**	25.9	86.8	110.1
	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)**	14.5	NA	NA
	This case represents the "Free-Flow" NYCA case where internal transmission constraints are eliminated and measures the impact of transmission constraints on statewide IRM requirements.			
3	**No Load Forecast Uncertainty**	8.9	74.8	94.8
	This scenario represents "perfect vision" for 2014 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**	13.8	80.8	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 or EDRPs**	15.2	78.6	102.5
	Shows the impact of SCRs and EDRPs on IRM.			
6	**Use NYISO proposed SCR adjustment factor of 0.765**	17.5	80.9	102.5
	ICS rejected NYISO's proposal to use 0.765. This case examines the impact of using that proposal.			
7a	**Forward Capacity Market (FCM) Sales to NE of 135 MW**	17.3	81.0	102.7
	Based on the minimum FCM sales to NE seen over the summer of 2015 (this amount is in addition to the roughly 90 MW of firm power sales from the NYPA Federal Power Contracts). Loss of units is made up with zonal average capacity.			
7b	**Forward Capacity Market Sales to NE of 405 MW**	17.2	81.5	103.4
	Based on the maximum FCM sales to NE estimated at three times the minimum MW seen over the summer of 2015 (this amount is in addition to the roughly 90 MW of firm power sales from the NYPA Federal Power Contracts). Loss of units is made up with zonal average capacity.			
8	**Multiple years of wind shape data (2012-2015)**	17.1	80.8	102.4
	A beta version of new GE software was tested and 4 years of wind production data was used. The new model randomly draws a daily shape from one of the 4 years. Five years will be used, similar to thermal units, in the future.			
9	**Incorporate 2014 Wind Shape**	16.3	80.8	102.4
	This sensitivity shows the impact of replacing the 2013 wind shape with the 2014 wind shape. LCRs are unaffected in this case due to adjustments being made only to zones west of UPNY/SENY.			
10	**Model Marble River Wind (assumes CRIS rights awarded)**	17.9	80.8	102.4
	An existing wind Farm, Marble River, has applied for CRIS rights during the class year 2015 process. The completion of the study has been delayed, but still could meet the June 1 cutoff date.			
11	**Sensitivity with the Huntley Coal fired generating units in Western NY remaining in Service**	17.0	80.9	102.6
	Assumes the Huntley units 67 and 68 do not retire.			

12	**Retire Indian Point 2 and 3**	LOLE of 0.62 days/year
	Starts with the base case and removes the Indian Point Units. The LOLE is recorded. This sensitivity was performed without adding any additional capacity.	

B.2 Impacts of Environmental Regulations

B.2.1 Regulations Reviewed for Impacts on NYCA Generators

The 2014 RNA identified new environmental regulatory programs that could impact the operation of the Bulk Power Transmission Facilities. These state and federal regulatory initiatives cumulatively have required considerable investment by the owners of New York's existing thermal power plants in order to comply. The following programs are reviewed here:

a) *NOx RACT*: Reasonably Available Control Technology (Effective July 2014)

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

c) *MATS*: Mercury and Air Toxics Standard for hazardous air pollutants (Effective April 2015, 2016, or 2017 depending on approved requests for extensions)

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

e) *CSAPR*: Cross State Air Pollution Rule for the reduction of SO_2 and NOx emissions in 28 Eastern States. The U.S. Supreme Court has upheld the CSAPR as promulgated by USEPA. The Supreme Court remanded the rule to the District Circuit Court of Appeals for further proceedings. Phase I became effective January 2015.

f) *RGGI*: Regional Greenhouse Gas Initiative Phase II cap reductions started January 2014. The Program design will be reviewed by the RGGI states in 2016.

g) *CO_2 Emission Standards*: NSPS effective June 2014, Existing Source Performance Standards become effective in 2022

h) *RICE*: NSPS and NESHAP – New Source Performance Standards and Maximum Achievable Control Technology for Reciprocating Internal Combustion Engines (Effective July 2016, however, the exemption for use of non-compliant engines in energy markets has been remanded back to USEPA).

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

The NYISO has determined that as much as 33,200 MW in the existing fleet (88% of 2014 Summer Capacity) will have some level of exposure to the new regulations.

B.3 Frequency of Implementing Emergency Operating Procedures

In all cases, it was assumed that the EOPs are implemented as required to meet the 0.1 days/year criterion. For the base case, the study shows that approximately 4.2 remote controlled voltage reductions per year would be implemented to meet the once in 10 years disconnection criterion. The expected frequency for each of the EOPs for the base case is provided in Table B.2.

Table B.2 Implementation of EOP steps

Step	EOP	Expected Implementation (Days/Year)
1	Require SCRs	8.9
2	Require EDRPs	6.3
3	5% manual voltage reduction	6.3
4	30 minute reserve to zero	6.2
5	5% remote controlled voltage reduction	4.2
6	Voluntary load curtailment	3.5
7	Public appeals	3.3
8	Emergency purchases	3.2
9	10 minute reserve to zero	3.1
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

C.1 NYCA and NYC and LI Locational Translations

In the “Installed Capacity” section of the NYISO Web site, the NYISO Staff regularly posts ICAP and UCAP calculations for both the summer and winter Capability Periods. This publicly available information can be found on the NYISO web site.[3]

Information has been compiled by the NYISO on this site since 2006 and includes complete information through 2015. This information is provided for Locational Areas and for the Transmission District Loads.

The Locational Areas include NYC, LI, G-J and the entire NYCA. Exhibits C.1.1 through C.1.4 summarizes translation of ICAP requirements to UCAP requirements for these Locational Areas. The charts and tables included in these exhibits utilize data from the 2006-2015 capability periods (and limited to “summer” only, for purposes of simplicity).

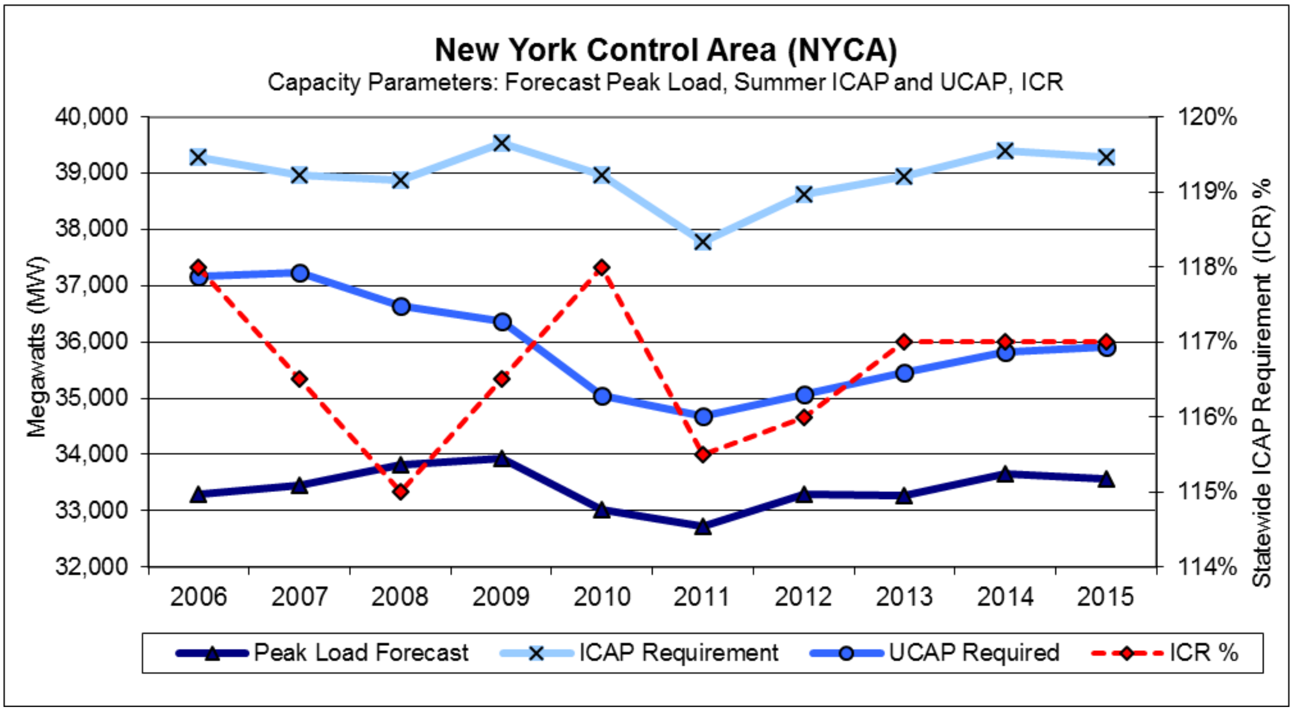
Importantly, this data reflects the interaction and relationships between the capacity parameters used this study, including Forecast Peak Load, ICAP Requirements, Derating Factors, UCAP Requirements, IRM and LCRs. Since these parameters are so inextricably linked to each other, the graphical representation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

[3] http://icap.nyiso.com/ucap/public/ldf_view_icap_calc_selection.do

C.1.1 New York Control Area ICAP to UCAP Translation

Table C.2 NYCA ICAP to UCAP Translation

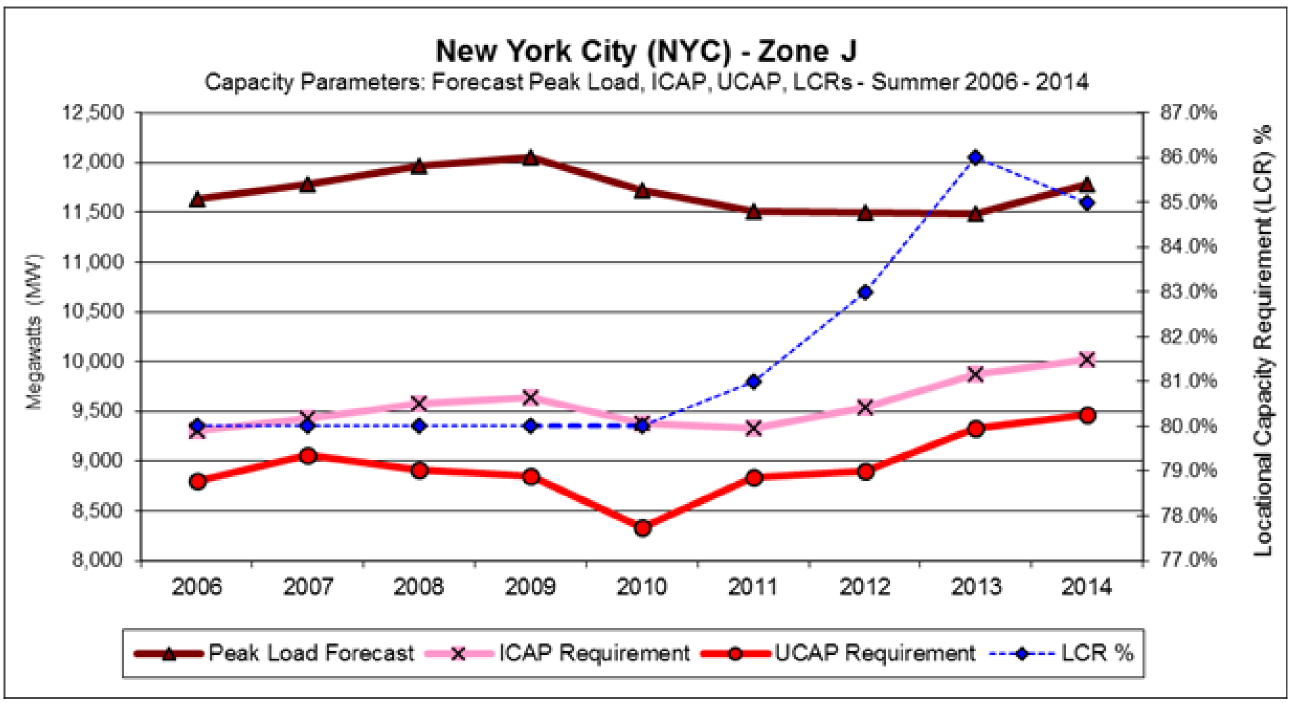
Year	Forecast Peak Load (MW)	Installed Capacity Requirement (%)	Derate Factor	ICAP Requirement (MW)	UCAP Requirement (MW)	Effective UCAP (%)
2006	33,295	118.0	0.0543	39,288	37,154	111.6
2007	33,447	116.5	0.0446	38,966	37,228	111.3
2008	33,809	115.0	0.0578	38,880	36,633	108.4
2009	33,930	116.5	0.0801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



C.1.2 New York City ICAP to UCAP Translation

Table C.3 New York City ICAP to UCAP Translation

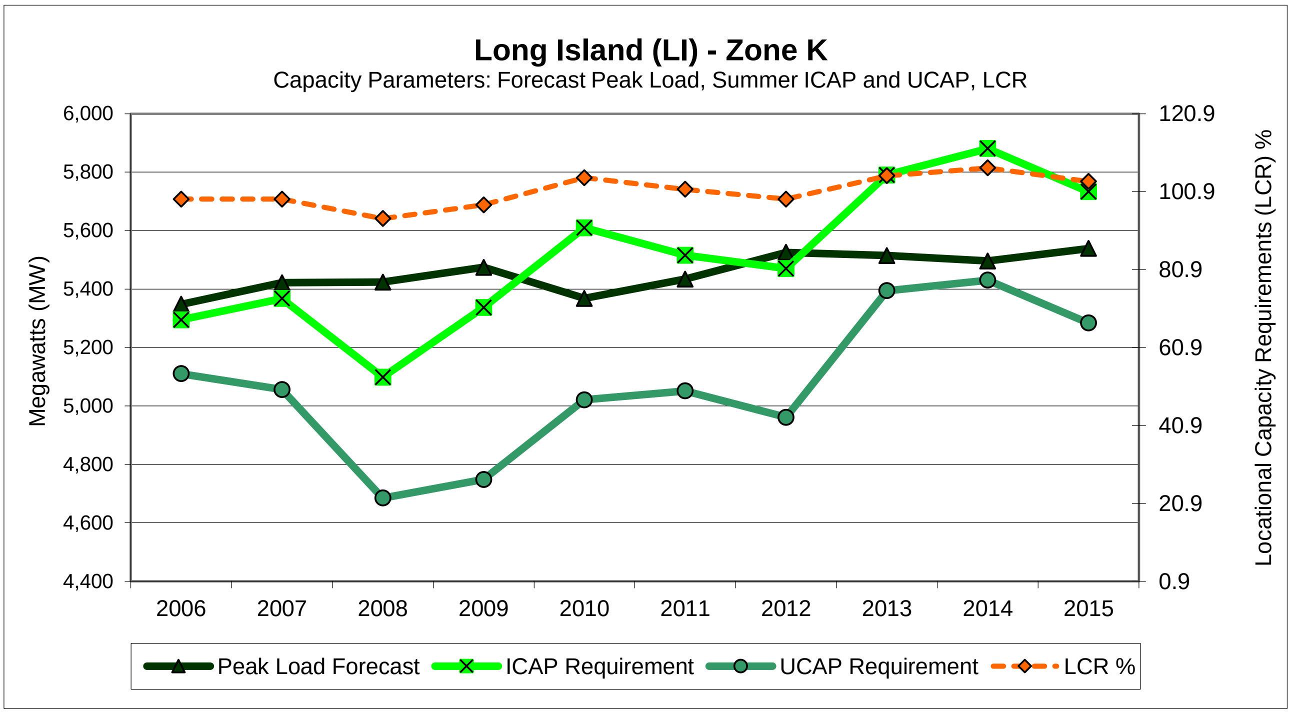
Year	Forecast Peak Load (MW)	Locational Capacity Requirement (%)	Derate Factor	ICAP Requirement (MW)	UCAP Requirement (MW)	Effective UCAP (%)
2006	11,628	80.0	0.0542	9,302	8,798	75.7
2007	11,780	80.0	0.0388	9,424	9,058	76.9
2008	11,964	80.0	0.0690	9,571	8,911	74.5
2009	12,050	80.0	0.0814	9,640	8,855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



C.1.3 Long Island ICAP to UCAP Translation

Table C.4 Long Island ICAP to UCAP Translation

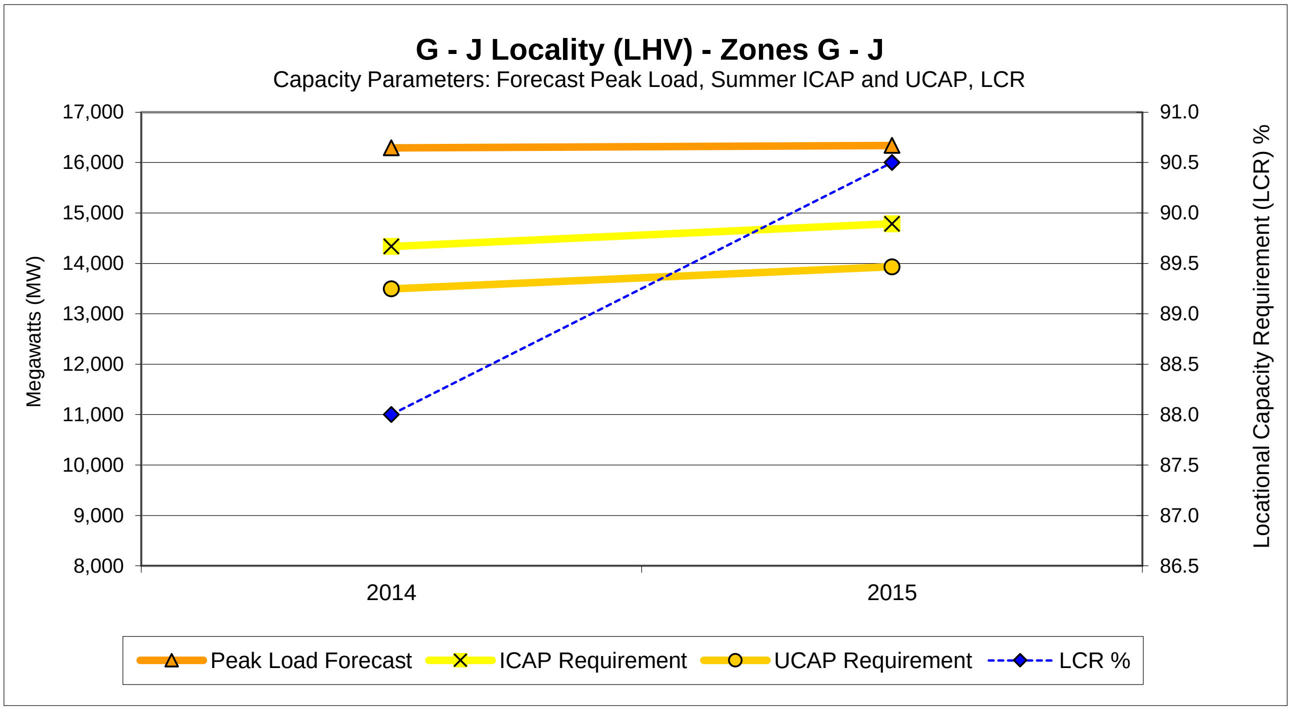
Year	Forecast Peak Load (MW)	Locational Capacity Requirement (%)	Derate Factor	ICAP Requirement (MW)	UCAP Requirement (MW)	Effective UCAP (%)
2006	5,348	99.0	0.0348	5,295	5,110	95.6
2007	5,422	99.0	0.0580	5,368	5,056	93.3
2008	5,424	94.0	0.0811	5,098	4,685	86.4
2009	5,474	97.5	0.1103	5,337	4,748	86.7
2010	5,368	104.5	0.1049	5,610	5,021	93.5
2011	5,434	101.5	0.0841	5,516	5,052	93.0
2012	5,526	99.0	0.0931	5,470	4,961	89.8
2013	5,515	105.0	0.0684	5,790	5,394	97.8
2014	5,496	107.0	0.0765	5,880	5,431	98.8
2015	5,539	103.5	0.0783	5,733	5,284	95.4



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

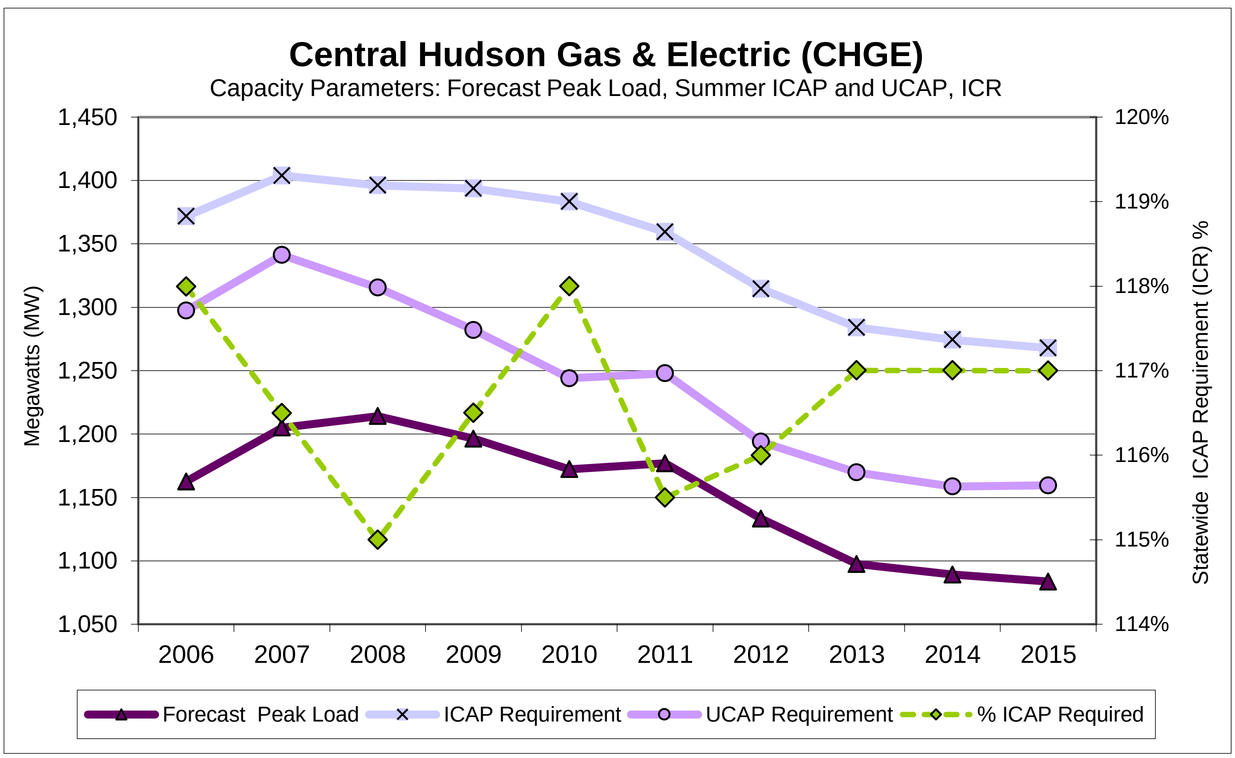


C.2 Transmission Districts ICAP to UCAP Translation

C.2.1 Central Hudson Gas & Electric

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

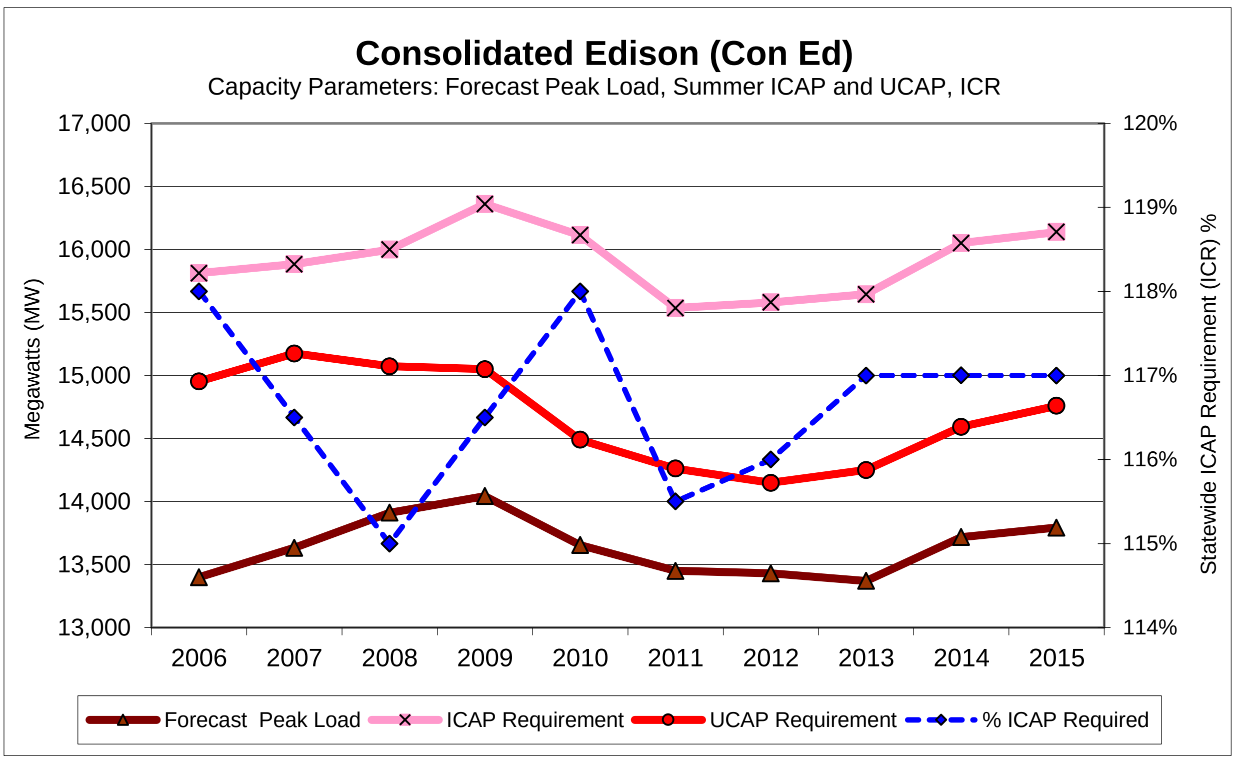
Year	Forecast Peak Load (MW)	ICAP Requirement (MW)	UCAP Requirement (MW)	%ICAP of Forecast Peak	%UCAP of Forecast Peak
2006	1,163	1,372	1,297	118.0%	111.6%
2007	1,205	1,404	1,341	116.5%	111.3%
2008	1,214	1,396	1,316	115.0%	108.4%
2009	1,196	1,394	1,282	116.5%	107.2%
2010	1,172	1,383	1,244	118.0%	106.1%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



C.2.2 Consolidated Edison (Con Ed)

Table C.7 Con Ed ICAP to UCAP Translation

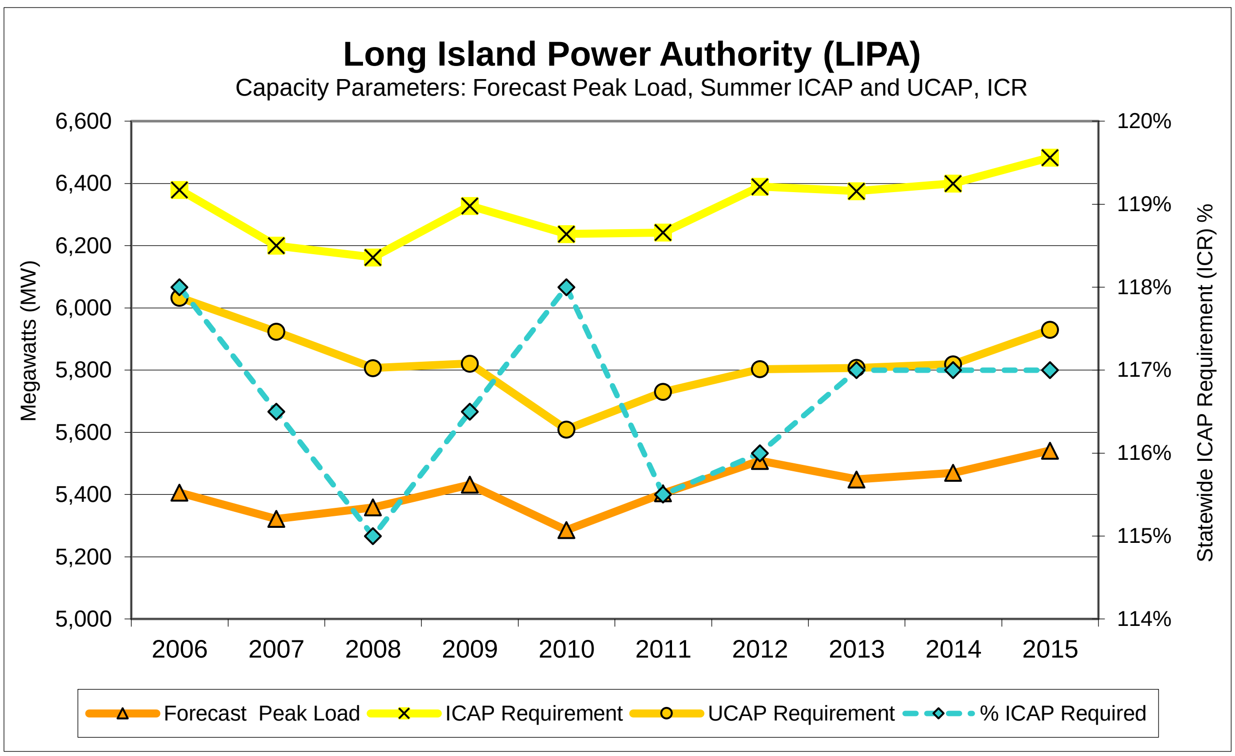
Year	Forecast Peak Load (MW)	ICAP Requirement (MW)	UCAP Requirement (MW)	%ICAP of Forecast Peak	%UCAP of Forecast Peak
2006	13,400	15,812	14,953	118.0%	111.6%
2007	13,634	15,883	15,175	116.5%	111.3%
2008	13,911	15,998	15,073	115.0%	108.4%
2009	14,043	16,360	15,050	116.5%	107.2%
2010	13,655	16,113	14,490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



C.2.3 Long Island Power Authority (LIPA)

Table C.8 LIPA ICAP to UCAP Translation

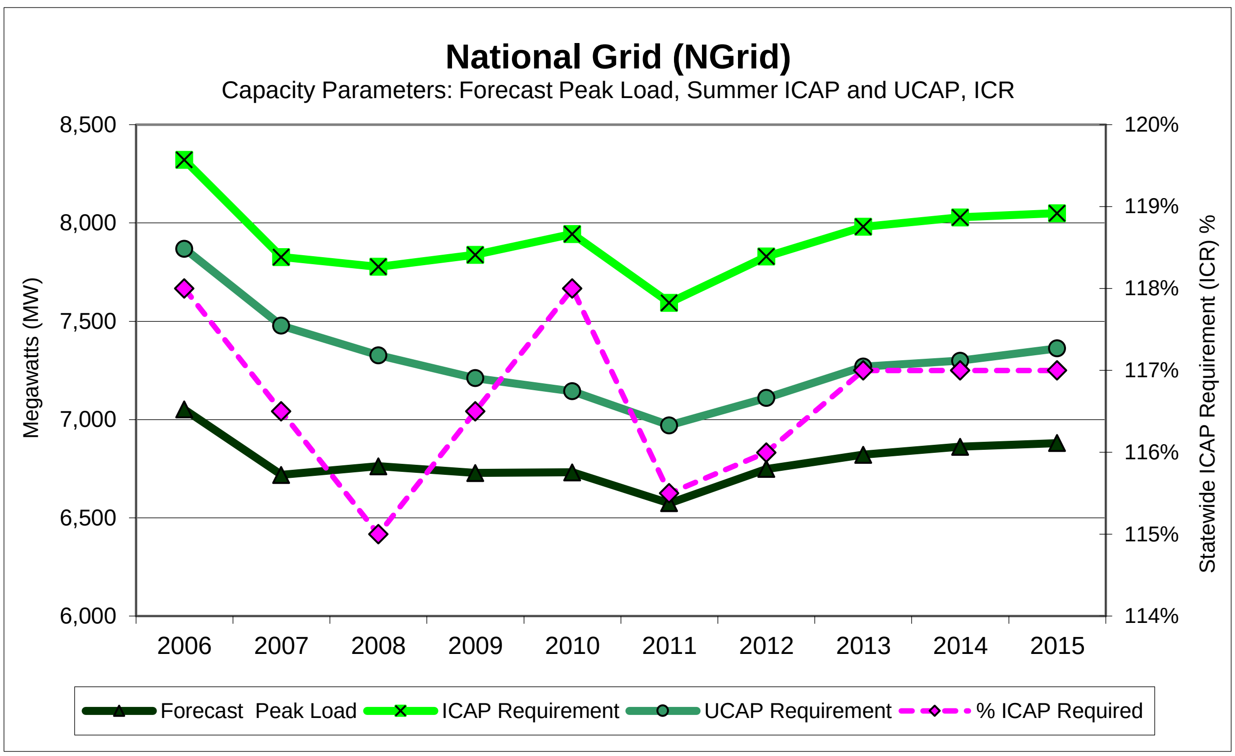
Year	Forecast Peak Load (MW)	ICAP Requirement (MW)	UCAP Requirement (MW)	%ICAP of Forecast Peak	%UCAP of Forecast Peak
2006	5,406	6,379	6,033	118.0%	111.6%
2007	5,322	6,200	5,923	116.5%	111.3%
2008	5,359	6,163	5,807	115.0%	108.4%
2009	5,432	6,328	5,821	116.5%	107.2%
2010	5,286	6,238	5,609	118.0%	106.1%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



C.2.4 National Grid (NGRID)

Table C.9 NGRID ICAP to UCAP Translation

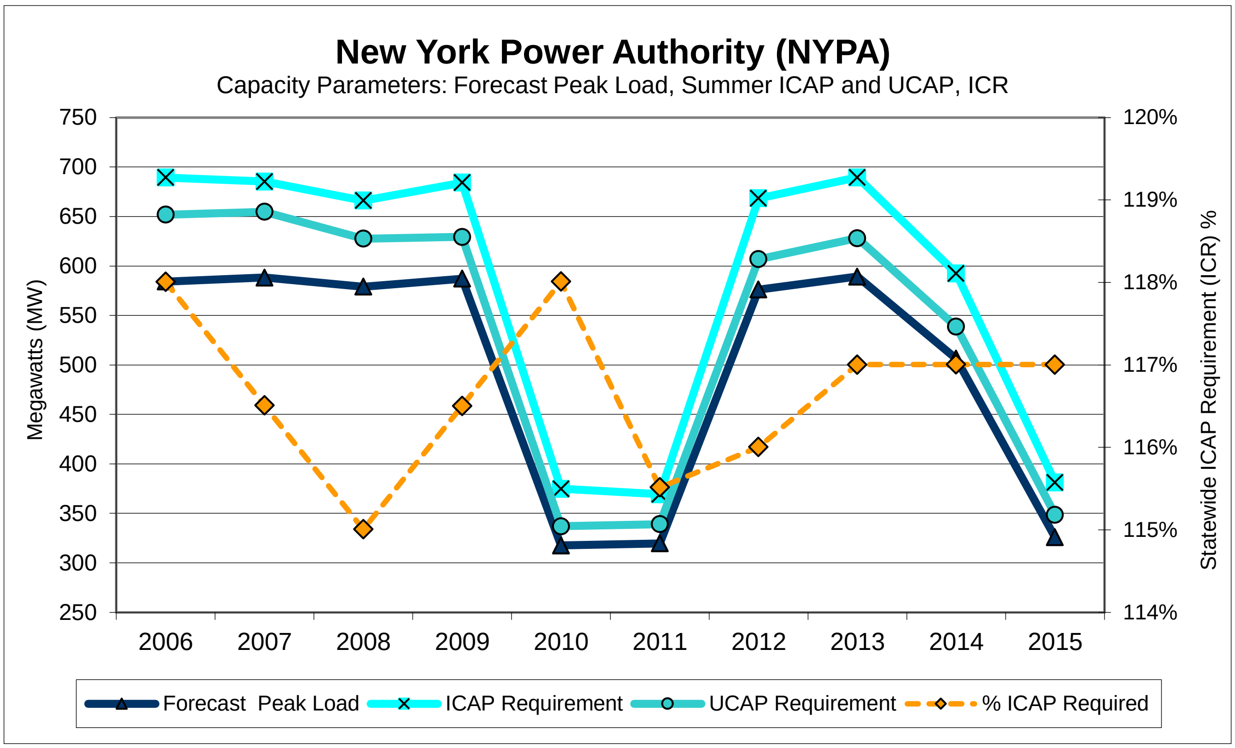
Year	Forecast Peak Load (MW)	ICAP Requirement (MW)	UCAP Requirement (MW)	%ICAP of Forecast Peak	%UCAP of Forecast Peak
2006	7,052	8,321	7,869	118.0%	111.6%
2007	6,719	7,827	7,478	116.5%	111.3%
2008	6,763	7,777	7,327	115.0%	108.4%
2009	6,728	7,839	7,211	116.5%	107.2%
2010	6,732	7,944	7,144	118.0%	106.1%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



C.2.5 New York Power Authority (NYPA)

Table C.10 NYPA ICAP to UCAP Translation

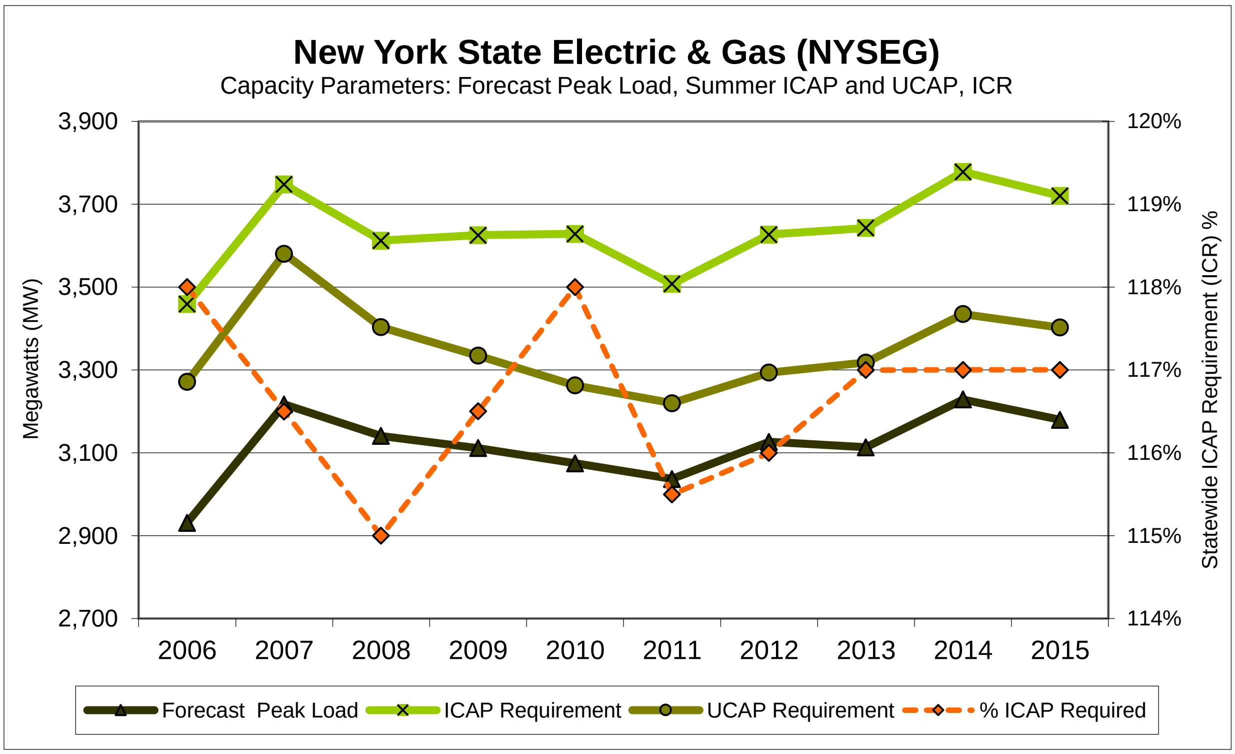
Year	Forecast Peak Load (MW)	ICAP Requirement (MW)	UCAP Requirement (MW)	%ICAP of Forecast Peak	%UCAP of Forecast Peak
2006	584	689	652	118.0%	111.6%
2007	588	685	655	116.5%	111.3%
2008	579	666	628	115.0%	108.4%
2009	587	684	629	116.5%	107.2%
2010	318	375	337	118.0%	106.1%
2011	320	369	339	115.5%	106.0%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



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

Table C.11 NYSEG ICAP to UCAP Translation

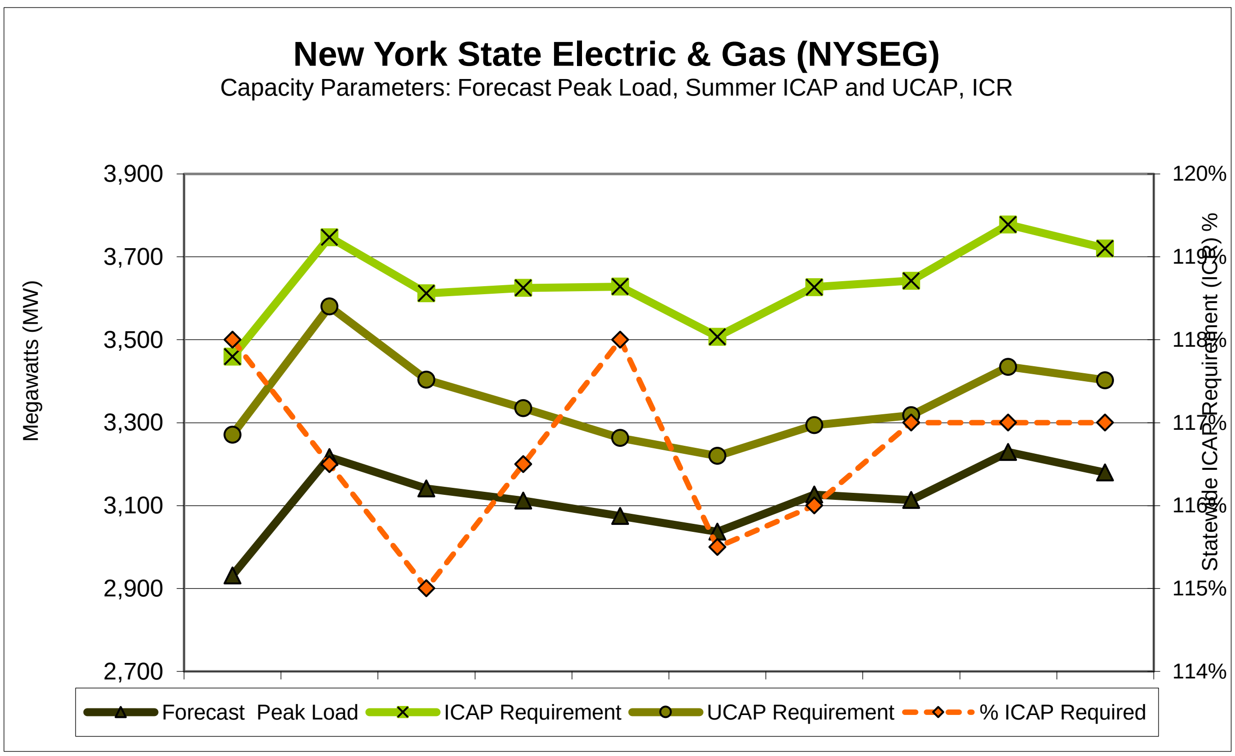
Year	Forecast Peak Load (MW)	ICAP Requirement (MW)	UCAP Requirement (MW)	%ICAP of Forecast Peak	%UCAP of Forecast Peak
2006	2,932	3,459	3,271	118.0%	111.6%
2007	3,217	3,748	3,581	116.5%	111.3%
2008	3,141	3,612	3,404	115.0%	108.4%
2009	3,112	3,625	3,335	116.5%	107.2%
2010	3,075	3,629	3,263	118.0%	106.1%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



C.2.7 Orange & Rockland (O & R)

Table C.12 O & R ICAP to UCAP Translation

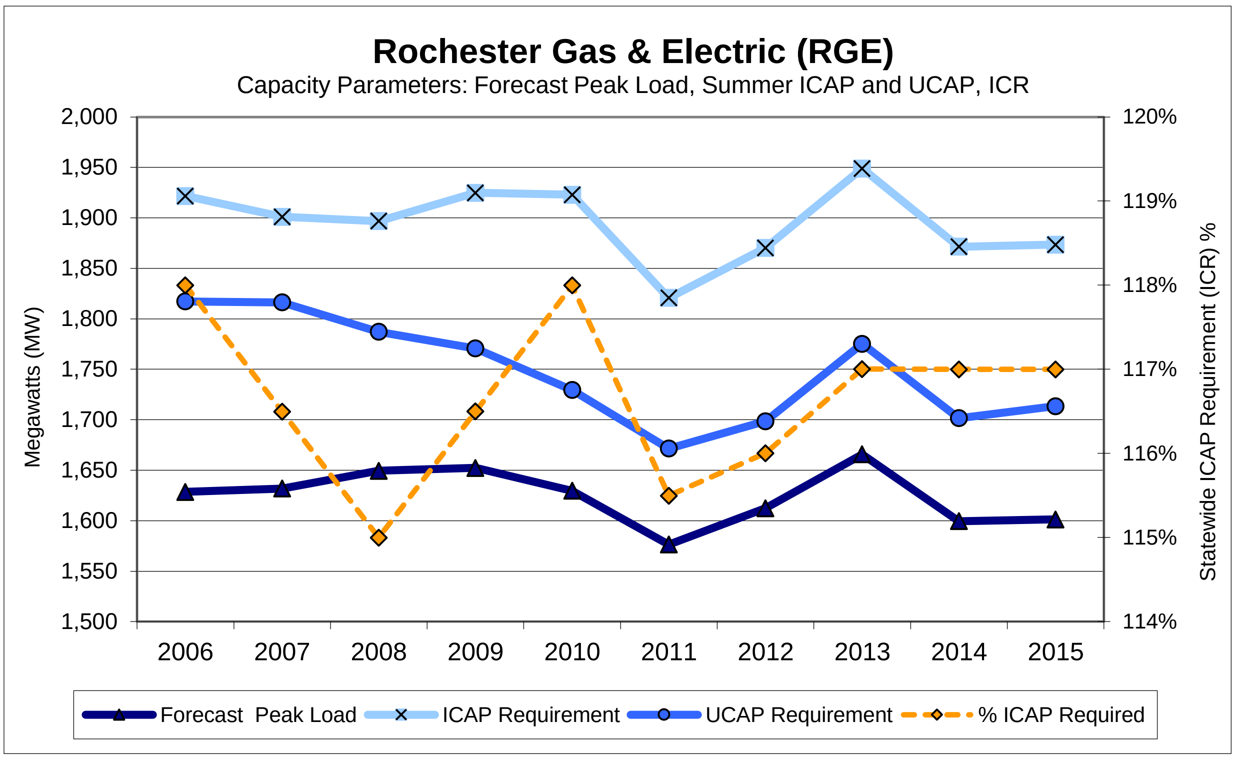
Year	Forecast Peak Load (MW)	ICAP Requirement (MW)	UCAP Requirement (MW)	%ICAP of Forecast Peak	%UCAP of Forecast Peak
2006	2,932	3,459	3,271	118.0%	111.6%
2007	3,217	3,748	3,581	116.5%	111.3%
2008	3,141	3,612	3,404	115.0%	108.4%
2009	3,112	3,625	3,335	116.5%	107.2%
2010	3,075	3,629	3,263	118.0%	106.1%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



C.2.8 Rochester Gas & Electric (RGE)

Table C.13 RGE ICAP to UCAP Translation

Year	Forecast Peak Load (MW)	ICAP Requirement (MW)	UCAP Requirement (MW)	%ICAP of Forecast Peak	%UCAP of Forecast Peak
2006	1,629	1,922	1,817	118.0%	111.6%
2007	1,632	1,901	1,816	116.5%	111.3%
2008	1,649	1,897	1,787	115.0%	108.4%
2009	1,652	1,925	1,771	116.5%	107.2%
2010	1,630	1,923	1,729	118.0%	106.1%
2011	1,576	1,821	1,671	115.5%	106.0%
2012	1,612	1,870	1,699	116.0%	105.4%
2013	1,666	1,949	1,775	117.0%	106.6%
2014	1,600	1,872	1,702	117.0%	106.4%
2015	1,601	1,874	1,714	117.0%	107.0%



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

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

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

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

In general, effective wind capacity depends primarily on the availability of the wind. Wind farms in New York on average have annual capacity factors that are on the order of 25% 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 on average 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 calculation of the effective capacity value for wind generation in New York is based on 2013 wind production/generation data and was calculated to be 14%. This means on average 14% of a wind generator nameplate rating will be available across the summer peak hours.

Appendix D

Glossary of Terms

D. Glossary

Term	Definition
Availability	A measure of time a generating unit, transmission line, or other facility is capable of providing 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.