New York Control Area Installed Capacity Requirements for the Period May 2008 through April 2009

Technical Study Report

December 14, 2007

New York State Reliability Council, LLC
Installed Capacity Subcommittee

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EXECUTIVE SUMMARY

A New York Control Area (NYCA) Installed Reserve Margin (IRM) Study is conducted annually by the New York State Reliability Council (NYSRC) Installed Capacity Subcommittee to provide parameters for establishing NYCA IRM requirements for the following capability year. This year's report covers the period May 2008 to April 2009 (2008 capability year).

Results of the NYSRC technical study show that the required NYCA IRM for the 2008 capability year is 15.0% under base case conditions.

For this base case, the study also determined Minimum Locational Capacity Requirements (MLCRs) of 79% and 94% for New York City (NYC) and Long Island (LI), respectively.

In its role of setting the appropriate locational capacity requirements (LCRs), the New York Independent System Operator (NYISO) will consider these MLCRs. These results satisfy and are consistent with all NYSRC Reliability Rules and Northeast Power Coordinating Council (NPCC) and North American Electric Reliability Corporation (NERC) reliability standards.

The above 2008 base case IRM Study result is 1.0 percentage point less than the base case IRM requirement determined by the 2007 IRM Study. The principle reasons for this reduction in required IRM are:

1. The continued improvement of NYCA generating unit availability,
2. Updated NYCA transmission topology which includes improvements to the Dunwoodie-South Interface and inclusion of the 660 MW Neptune HVDC facilities.
3. Improved emergency assistance benefits from interconnections to neighboring Control Areas, primarily due to transmission reinforcements within these Areas, and
4. A reduction of transmission cable outage rates.

Table 2 shows the IRM impacts of these factors that have permitted an IRM reduction from the 2007 IRM base case value of 16.0%.

The study also evaluated IRM requirement impacts of several sensitivity cases. These results are depicted in Table 3 and in Appendix Table B-2. In addition, a confidence interval analysis was conducted to determine the IRM range around the base case IRM that provides a high confidence of meeting the reliability index within the NYSRC resource adequacy criterion.

The base case and sensitivity case results, along with other relevant factors, will be considered by the NYSRC Executive Committee for its adoption of the Final NYCA IRM requirement for the 2008 capability year.

INTRODUCTION

This report describes a technical study, conducted by the NYSRC Installed Capacity Subcommittee, for establishing the NYCA IRM for the period of May 1, 2008 through April 30, 2009 (2008 capability year). This study is conducted each year in compliance with Section 3.03 of the NYSRC Agreement which states that the NYSRC shall establish the annual statewide Installed Capacity Requirement (ICR) for the NYCA. The ICR relates to the IRM through the following equation:

$$\mathbf{ICR = (1 + IRM\% / 100) \times Forecasted\ NYCA\ Peak\ Load}$$

The base case and sensitivity case study results, along with other relevant factors, will be considered by the NYSRC Executive Committee for its adoption of the Final NYCA IRM requirement for the 2008 capability year.

The NYISO will implement the final NYCA IRM as determined by the NYSRC — in accordance with the NYSRC Reliability Rules and the NYISO Installed Capacity manual. The NYISO translates the required IRM to an Unforced Capacity (UCAP) basis. These values are also used in a Spot Market Auction based on FERC-approved Demand Curves. These Unforced Capacity and Demand Curve concepts are described later in the report. The schedule for the IRM study is based on the NYISO's timetable for these actions.

The study criteria, procedures, and types of assumptions used for this 2008 IRM Study are in accordance with NYSRC Policy 5-1, *Procedure for Establishing New York Control Area Installed Capacity Requirements,* dated November 14, 2006. The primary reliability criterion used in the IRM study requires, on average, a Loss of Load Expectation (LOLE) of no more than once in 10 years for the NYCA. This NYSRC resource adequacy criterion is consistent with NPCC and NERC reliability standards. IRM study procedures include the use of two study methodologies, the *Unified* and the *IRM Anchoring Methodologies.* The above reliability criterion and methodologies are discussed in more detail later in the report. In addition to calculating the NYCA IRM requirement, these methodologies identify corresponding MLCRs for NYC and LI. In its role of setting the appropriate LCRs, the NYISO will utilize the same study methodologies and procedures as in the 2008 IRM Study, and will consider the MLCR values determined in this study.

On June 7, 2007 the NYSRC conducted a Resource Adequacy Workshop to provide the NYISO, market participants, and NYS Department of Public Service staffs with a better understanding of probability theory and reliability analysis models, procedures, and assumptions as applied to NYCA IRM studies. Workshop material can be found at www.nysrc2.org/workshops.asp.

Previous NYCA 2000 to 2007 IRM Study reports can be found at www.nysrc2.org/reports.asp. Table B-1 in Appendix B provides a comparison of previous NYCA base case and Final IRMs for the 2000 through 2008 capability years. Definitions of certain terms in this report can be found in the NYSRC Glossary in the *NYSRC Reliability Rules for Planning and Operating the New York State Power System Manual*, at www.nysrc2.org/NYSRCReliabilityRulesComplianceMonitoring.asp .

NYSRC RESOURCE ADEQUACY RELIABILITY CRITERION

The acceptable LOLE reliability level used for establishing NYCA IRM Requirements is dictated by the NYSRC Reliability Rule A-R1, *Statewide Installed Reserve Margin Requirements,* which states:

> *The NYSRC shall establish the IRM requirement for the NYCA such that the probability (or risk) of disconnecting any firm load due to resource deficiencies shall be, on average, not more than once in ten years. Compliance with this criterion shall be evaluated probabilistically, such that the loss of load expectation (LOLE) of disconnecting firm load due to resource deficiencies shall be, on average, no more than 0.1 day per year. This evaluation shall make due allowance for demand uncertainty, scheduled outages and deratings, forced outages and deratings, assistance over interconnections with neighboring control areas, NYS Transmission System emergency transfer capability, and capacity and/or load relief from available operating procedures.*

This NYSRC Reliability Rule is consistent with the NPCC Resource Adequacy Standard in NPCC Document A-2.

In accordance with NYSRC Rule A-R2, *Load Serving Entity (LSE) Installed Capacity Requirements*, the NYISO is required to establish LSE installed capacity requirements, including locational capacity requirements, in order to meet the statewide IRM Requirements established by the NYSRC for maintaining NYSRC Rule A-R1 above.

The full NYSRC Reliability Rule A-R2 can be found in the NYSRC Reliability Rules Manual on the NYSRC Web site, at www.nysrc2.org/NYSRCReliabilityRulesComplianceMonitoring.asp.

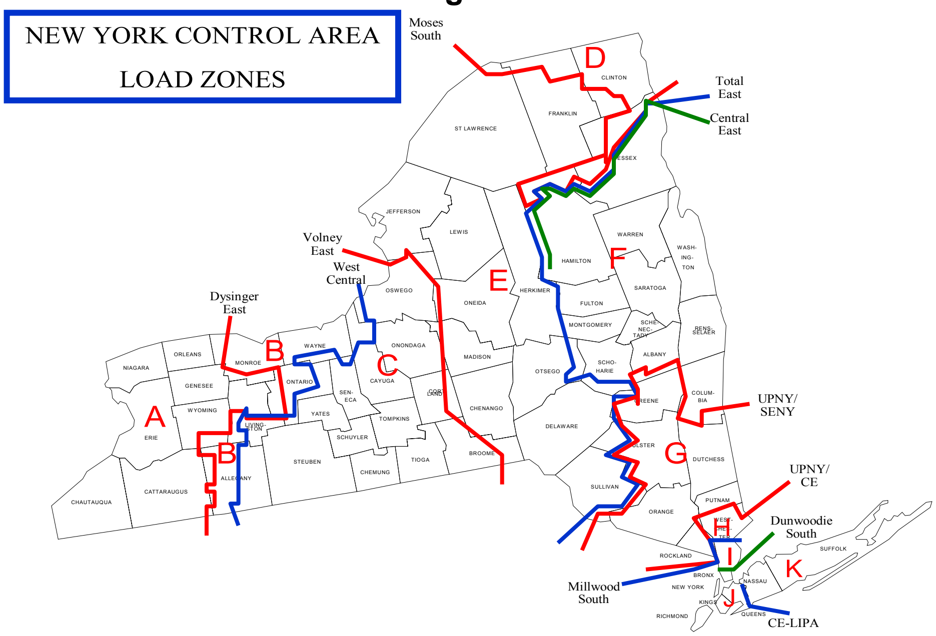
IRM STUDY PROCEDURES

The study procedures used for the 2008 IRM Study are described in detail in NYSRC Policy 5-1, *Procedure for Establishing New York Control Area Installed Capacity Requirements*. Policy 5-1 describes the computer program used for the reliability calculation in addition to the procedures and types of input data and models used for the IRM Study. Policy 5-1 can be found on the NYSRC Web site at, www.nysrc2.org/policies.asp.

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

General Electric's Multi-Area Reliability Simulation (GE-MARS) is the primary computer program used for this probabilistic analysis. This program includes detailed load, generation, and transmission representation for eleven NYCA Zones — plus four external Control Areas (“Outside World” Areas) directly interconnected to the NYCA. The eleven NYCA zones are depicted in Figure 1 below. GE-MARS calculates LOLE, expressed in days per year, to provide a consistent measure of system reliability.

Figure 1



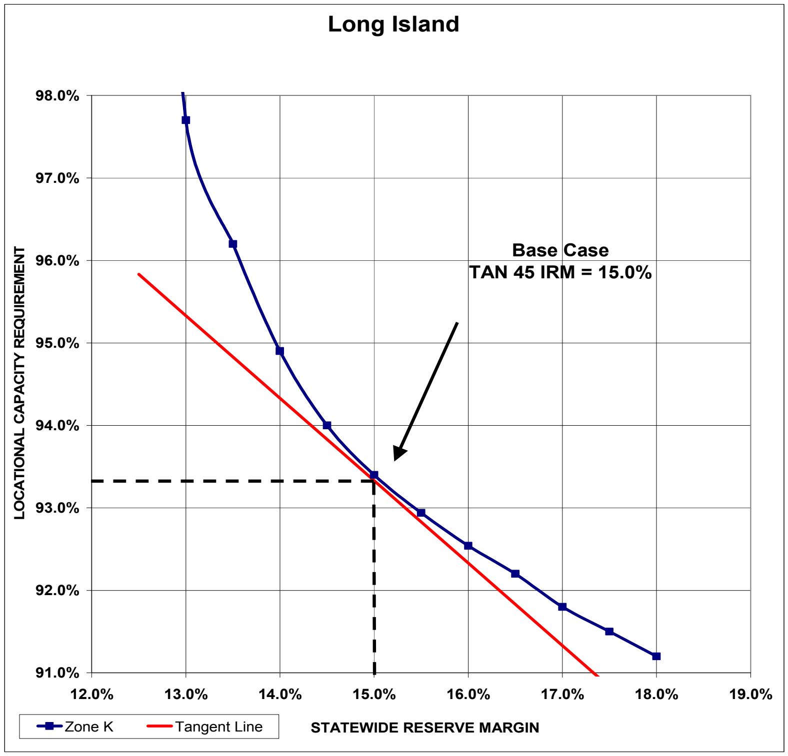
Using the GE-MARS program, a procedure is utilized for establishing NYCA IRM requirements (termed the *Unified Methodology)* which establishes a graphical relationship between NYCA IRM and MLCRs. All points on these curves meet the NYSRC 0.1 days/year LOLE reliability criterion described above. This methodology develops a pair of curves, one for NYC (Zone J) and one for LI (Zone K). Policy 5-1 provides a more detailed description of the Unified Methodology.

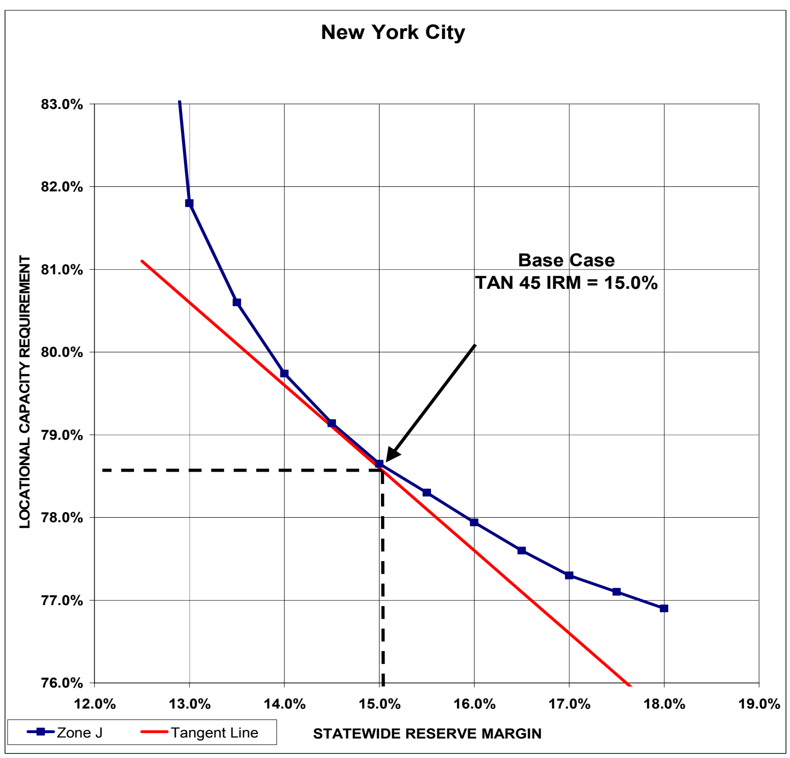
Base case NYCA IRM requirements and related MLCRs are established by a supplemental procedure (termed the *IRM Anchoring Methodology*) which is used to define an *inflection point* on each of these curves. These inflection points are selected by applying a tangent of 45 degrees (Tan 45) analysis at the bend (or “knee”) of each curve. Mathematically, each curve is fitted using a second order polynomial regression analysis. Setting the derivative of the resulting set of equations to minus one yields the points at which the curves achieve the Tan 45 degree inflection point. Appendix A-4.1 provides a more detailed description of the methodology for computing the Tan 45 inflection point.

BASE CASE STUDY RESULTS

Results of the NYSRC technical study show that the required NYCA IRM is 15.0% for the 2008 capability year under base case conditions. Figure 2 depicts the relationship between NYCA IRM requirements and resource capacity in NYC and LI. The points on the NYC and LI curves were calculated using the methodologies described in the previous “IRM Study

Figure 2
NYCA Locational ICAP Requirements vs.
Statewide ICAP Requirements
See Appendix A-4.1 for Mathematical Derivation





Procedures" section. The inflection points on these curves, from which the above base case study results are based, were evaluated using the Tan 45 analysis, also previously described. Accordingly, we conclude that maintaining a NYCA installed reserve of 15.0% for the 2008 capability year, together with MLCRs of 79% and 94% for NYC and LI, respectively, will achieve applicable NYSRC and NPCC reliability criteria for the base case study assumptions shown in Appendix A. The NYISO will consider these MLCRs when developing the final NYC and LI LCR values for the 2008 capability year.

A Monte Carlo simulation error analysis shows that there is a 99.7% probability that the above base case result is within a range of 14.3% and 15.8% (see Appendix A-2.1). Within this range the statistical significance of the 14.3%, 15.0%, and 15.8% numbers are a 0.15%, 50%, and 99.85% probability of meeting the one day in ten LOLE, assuming perfect accuracy of all parameters and using a standard error of 0.05. If a standard error of 0.025 were used, the band would tighten from 14.6 to 15.4%. The base case IRM value of 15.0% is in full compliance with NYSRC and NPCC reliability rules and criteria.

MODELS AND KEY INPUT ASSUMPTIONS

This section describes the models and related input assumptions for the 2008 IRM Study. The models represented in the GE-MARS analysis include a Load Model, Capacity Model, Transmission System Model, and Outside World Model. Appendix A provides more details of these models and assumptions.

Load Model

- ***Peak Load Forecast***: A 2008 NYCA summer peak load of 33,730 MW was assumed in the study. This load forecast was prepared by the NYISO Staff in October 2007 and is based on actual 2007 summer load conditions. Although the NYISO will prepare a final 2008 summer forecast in early 2008 for use in NYISO locational capacity and other studies, it is expected that both forecasts will be similar.

- ***Load Shape Model***: The 2008 IRM Study was performed using a load shape based on 2002 actual values. The 2002 load shape was compared to load shapes from 1999 through 2006. The conclusion reached in this recent analysis was that the load shape used for this year's study should be the same as in the 2006 and 2007 IRM Studies, i.e., the 2002 load shape is best suited for the 2008 IRM Study.

- ***Load Forecast Uncertainty (LFU):*** It is recognized that some uncertainty exists relative to forecasting NYCA loads for any given year. This uncertainty is incorporated in the base case model by using a load forecast probability distribution that is sensitive to different weather and economic conditions. Recognizing the unique LFU of individual NYCA areas, the LFU model is subdivided into four areas: Zone H and I, Zone J (NYC), Zone K (LI), and Zones A-G (the rest of New York State). Recognizing LFU in the base case increases the IRM requirements by 7.3% (see Table 3).

Capacity Model

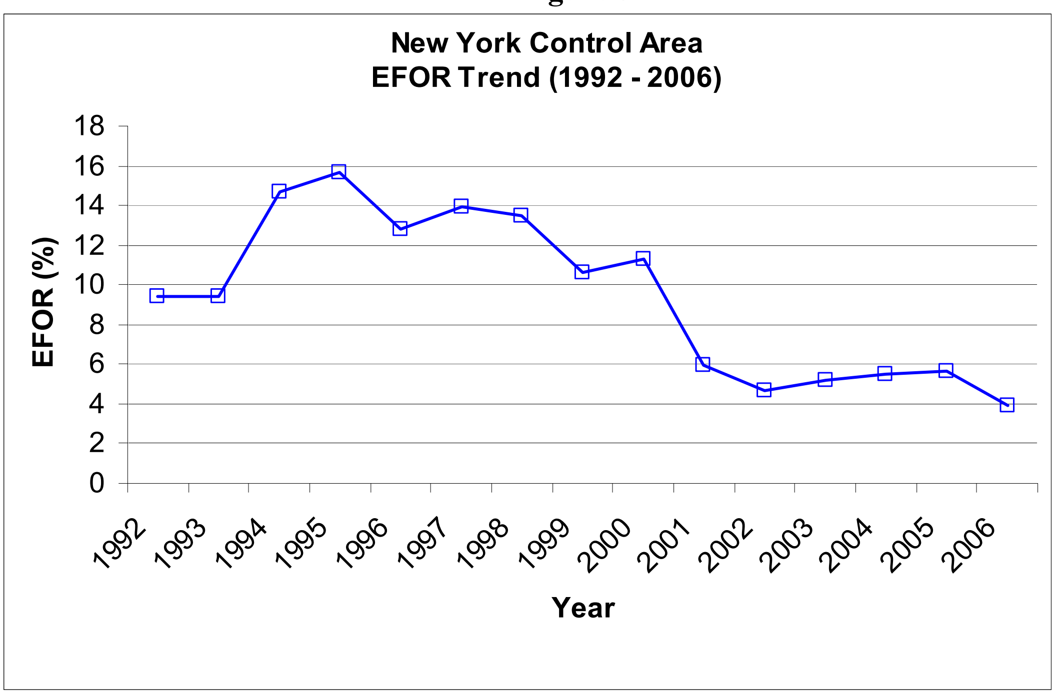
The capacity model in MARS incorporates the several considerations, as discussed below:

- ***Resource Facility Ratings****:* The rating for each existing and planned resource facility in the capacity model is based on its Dependable Maximum Net Capability (DMNC). The source of DMNC ratings for existing facilities is seasonal tests required by procedures in the NYISO Installed Capacity Manual. Appendix A shows the new resource facilities that are included in the 2008 IRM Study capacity model.

- ***Resource Capacity Availability****:* Generating unit forced and partial outages are modeled in GE-MARS by inputting a multi-state outage model that represents an "equivalent forced outage rate on demand" (EFORd) for each unit represented. Outage data is received by the NYISO from generator owners based on specific reporting requirements established by the NYISO. Capacity unavailability is modeled by considering the average forced and partial outages for each generating unit that have occurred over the most recent five-year time period. The time span considered for the 2008 IRM Study covered the 2002–2006 period.

  Generating unit availability performance has stabilized over the past six years. As depicted in Figure 3 below, the NYCA average annual EFOR during the 2001-2006 period have been consistently in the range of 4 to 6%. This is a substantial improvement from the 9 to 16% EFOR range experienced during the prior nine years. Improvement of generating unit availability has permitted the required IRM to be reduced by 1.1% since the 2005 capability year, that is, without this improvement the 2008 IRM base case IRM would have been 16.1% instead of 15.0%.

Figure 3



- ***Generating Unit Ambient Deratings****:* Gas turbine and combined cycle capacity deratings are modeled using ambient temperature correction curves. Deratings of generating units affected by extreme summer temperature conditions are recognized in this model. Based on its review of historical 2006 and 2007 data, the NYISO staff has updated the simple cycle combustion turbine derate model to include what is termed the bias. The NYISO plans to extend this analysis in the future to include other capacity limited resources. Although this analysis indicates a bias at design temperatures, it also shows an approximate one-third reduction in the amount of correction occurring at higher temperatures as compared to the 2007 IRM Study. The net effect of replacing the 2007 IRM Study's combustion turbine derate model with this year's updated model is a slight reduction in LOLE. 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 at www.nysrc2.org/reports.asp .

- ***Emergency Operating Procedures****:*

  -- **Special Case Resources (SCRs)**. SCRs are ICAP resources that include loads that are capable of being interrupted — and distributed generation that may be activated on demand. This study assumes 1,323 MW of SCR resource capacity in July and August (and lesser amounts during other months), limited to a maximum of four SCR calls per month in July and August for NYS Department of Environmental Conservation-limited generation. The above SCR capacity was discounted to a base case value of 1,205 MW (reflecting past performance) for the 2008 Study.

  -- Emergency Demand Response Programs (EDRP). EDRP allows registered interruptible loads and standby generators to participate on a voluntary basis - and be paid for their ability to restore operating reserves. The 2008 Study assumes 430 MW of EDRP capacity resources will be registered in 2008. This EDRP capacity was discounted to a base case value of 193.5 MW (reflecting past performance) and is implemented in the study in July and August (and lesser amounts during other months), while being limited to a maximum of five EDRP calls per month. Both SCRs and EDRP are included in the Emergency Operating Procedure (EOP) model.

  -- Other Emergency Operating Procedures. In accordance with NYSRC/NPCC criteria, the NYISO will implement EOPs as required to minimize customer disconnections. (Refer to Appendix B, Table B-3, for the expected use of SCRs, EDRP, voltage reductions, and other EOPs during 2008, assuming an IRM of 15.0 %.)

- ***Unforced Capacity Deliverability Rights (UDRs):*** The Capacity Model includes UDRs which are capacity rights that allow the owner of an incremental controllable transmission project to extract the locational capacity benefit derived by the NYCA from the project. Non-locational capacity, when coupled with a UDR, can be used to satisfy locational capacity requirements. The owner of UDR facility rights designates how they will be treated by the NYSRC and NYISO for resource adequacy studies. The NYISO calculates the actual UDR award based on the performance characteristics of the facility and other data. LIPA's 330 MW HVDC Cross Sound Cable and 660 MW HVDC Neptune Cable are facilities that are represented in the 2008 Study as having UDR capacity rights. LIPA has the option, on an annual basis, of selecting the MW quantity of UDRs (ICAP) it plans on utilizing for capacity contracts over these facilities. Any remaining capability on the cable can be used to support emergency assistance which may reduce locational and IRM requirements. The study incorporates the elections that LIPA has made for the 2008 capability year.

Transmission System Model

A detailed transmission system model is represented in the GE-MARS study. The transmission system topology, which includes the eleven NYCA zones and four Outside World Areas, along with transfer limits, is shown in Figure A-10 in Appendix A. A notable addition in the 2008 IRM Study transmission model is LIPA's Neptune HVDC submarine cable which was energized during the summer of 2007. This cable connects Long Island and PJM and has a 660 MW rating. In addition to this new HVDC cable there were improvements in the transfer capability of the Dunwoodie-South interface and the reconductoring of the Northeast Utilities Service Company (NUSCO) 1385 submarine cables. These modeled improvements increased the ability of the system to transfer capacity. A fuller description of these improvements can be found in Appendix A.

GE-MARS is capable of determining the impact of transmission constraints on NYCA LOLE. This study, as with previous GE-MARS studies, reveals that the transmission system into NYC and LI is constrained and can impede the delivery of emergency capacity assistance required to meet load within these zones. The NYSRC has two reliability planning criteria that recognize transmission constraints: (1) the NYCA IRM requirement considers transmission constraints into NYC and LI, and (2) minimum LCRs must be maintained for both NYC and LI (See NYSRC Resource Adequacy Reliability Criteria section).

The impact of transmission constraints on NYCA IRM requirements depends on the level of resource capacity in NYC and LI. In accordance with NYSRC Reliability Rule A-R2, *Load Serving Entity ICAP Requirements,* the NYISO is required to calculate and establish appropriate LCRs. The most recent NYISO study (*Locational Installed Capacity Requirements Study,* dated February 16, 2007, at www.nyiso.com/public/webdocs/services/planning/resource_adequacy/lcr_review2_16.pdf) determined that for 2007 capability year, the required LCRs for NYC and LI were 80% and 99%, respectively.

As previously discussed, Figure 2 depicts the relationship between NYCA IRM requirements and resource capacity in NYC and LI for the base case. This figure shows that the IRM requirement can be impacted significantly depending on the level of capacity within these zones, particularly to the right of the "inflection point" of the curve where the IRM requirement rises much faster than the locational installed capacity levels are reduced. For base case assumptions, the inflection point in Figure 2 results in the base case IRM requirement of 15.0% and MLCRs for NYC and LI of 79% and 94%, respectively.

Results from this study illustrate the impact on the IRM requirement for changes of LCR level assumptions from the base case. Observations from these results include:

- **Unconstrained NYCA Case** – If internal transmission constraints were entirely eliminated the NYCA IRM requirement could be reduced to 12.6%, 2.4 percentage points less than the base case IRM requirement (see Table 3).

- **Downstate NY Capacity Levels** – If the NYC and LI LCR levels were *increased* from the base case results to 82% and 98%, respectively, the IRM requirement would be reduced by 2.0 percentage points, to 13.0%. Similarly, if the NYC and LI locational installed capacity levels were *decreased* to 77% and 91%, respectively, the IRM requirement would increase by about 3.0 percentage points, to 18.0% (see Figure 2).

These results illustrate the significant impact on IRM caused by transmission constraints and implementing different LCR levels, assuming all other factors being equal.

Outside World Model

The Outside World Model consists of Control Areas in Ontario, Quebec, New England, and PJM. NYCA reliability can be improved and IRM requirements can be reduced by recognizing available emergency assistance support from these neighboring interconnected control areas — in accordance with control area agreements during emergency conditions. Assuming such interconnection support arrangements in the base case reduces the NYCA IRM requirements by approximately 4.0 percentage points (see Table 3). A model for representing neighboring control areas, similar to that applied in previous IRM studies, was utilized in his study.

The primary consideration for developing the base case load and capacity assumptions for the Outside World Areas is to avoid overdependence on these Areas for emergency capacity support. For this purpose, from Policy 5-1, a rule is applied whereby an Outside World Area's LOLE cannot be lower than its own LOLE criterion, its isolated LOLE cannot be lower than that of the NYCA, and its IRM can be no higher than that Area's minimum requirement. Table 1 below compares the base case NYCA 2008 IRM with lower NYCA IRM requirements resulting from a scenario whereby each Outside World Area is represented by an IRM that meets its LOLE criterion.

Table 1
Impact of Alternate Outside World on NYCA IRM and LOLE

Outside Area IRMs	Required NYCA IRM
All Outside Areas at base case IRMs	15.0%
All Outside Areas with Reserve Margins that meet their LOLE Criteria*	9.8%

*Calculated by the NYISO. These results may not be consistent with results of similar studies conducted by the Outside World Areas because of different assumptions used.

Another consideration for developing models for the Outside World Areas is to recognize internal transmission constraints within the Outside World Areas that may limit emergency assistance to the NYCA. This recognition is considered either explicitly, or through direct multi-area modeling providing there is adequate data available to accurately model transmission interfaces and load areas within these Outside World Areas. For this study, two of the Outside World Areas – New England and PJM – are each represented as multi-areas. This level of granularity better captures the impacts of transmission constraints within these areas, particularly on their ability to provide emergency assistance to the NYCA.

Limitations across the Northport-Norwalk Harbor cable were modeled as a function of the availability of Norwalk Harbor generation. Limitations from Eastern PJM system across the Con Edison Hudson-Farragut, Linden-Gothels interconnections, and the new HVDC Neptune cable intertie, were modeled as a function of the availability of Northern New Jersey generation including Linden, Hudson, and Bergen.

COMPARISON WITH 2007 IRM STUDY RESULTS

The results of this 2008 IRM study show that the base case IRM result has decreased 1.0 percentage point compared to the 2007 IRM Study. Table 2 compares the estimated IRM impacts of changing several key study assumptions from the 2007 Study. The estimated percent IRM change for each parameter was calculated from the results of a parametric analysis. These results were grouped and then normalized such that the sum of the +/- % changes totals the 1.0 percentage point IRM reduction from the 2007 Study. The primary drivers that have reduced IRM requirements from the 2007 capability year are:

(1) The continued improvement of NYCA generating unit availability (see Table 2, Updated Generating Unit EFORs),

(2) Updated NYCA transmission topology which includes improvements to the Dunwoodie-South Interface and inclusion of the 660 MW Neptune HVDC facilities (see Table 2, Updated Transmission Topology).

(3) Improved emergency assistance benefits from interconnections to neighboring control areas, primarily due to transmission reinforcements within these Areas (see Updated Outside World Model in Table 2), and

(4) A reduction of transmission cable outage rates (see Updated Cable Outage Rates in Table 2).

Table 2
Parametric IRM Impact Comparison with 2007 Study

Parameter	Estimated IRM Change (%)	IRM (%)
Previous 2007 Study – Base Case IRM Result		**16.0**
Updated EOPs including SCRs and EDRP	+ 0.3	
New Units and Retirements	0.0	
Updated Load Model	0.0	
Updated Maintenance Schedule	0.0	
Updated GT Capacity Temperature Correction Model	0.0	
Updated Outside World Model	-0.2	
Updated Generating Unit EFORs	-0.3	
Updated Cable Outage Rates	- 0.3	
Updated NYS Transmission Topology	- 0.5	
Net Change from 2007 Study		**- 1.0**
2008 Study – Base Case IRM Result		**15.0**

SENSITIVITY CASE STUDY RESULTS

Determining the appropriate IRM requirement to meet NYSRC reliability criteria depends upon many factors. Variations from the base case will, of course, yield different results. Table 3 shows IRM requirement results and related NYC and LI locational capacities for several selected sensitivity cases. Sensitivity results are important input when the NYSRC Executive Committee develops the final NYCA 2008 IRM. A complete summary of all sensitivity case results are shown in Appendix B, Table B-2. Table B-2 also includes a description and explanation of each sensitivity case. Due primarily to time and resource constraints, there was no attempt to re-evaluate the “inflection point” or require each of the sensitivity case MLCR results to be consistent with base case MLCR results.

Table 3
NYCA IRM Requirements and Related NYC & LI Locational Capacities**

Case	Case Description	IRM (%)	% Change from Base Case	NYC(%)	LI(%)
0	Base Case	15.0	--	79.0	94.0
1	NYCA Isolated	19.0	+4.0	81.9	97.2
2	Decrease tie ratings on 5 upstate interfaces by 10%	15.1	+0.1	79.1	94.1
3	No Load Forecast Uncertainty	7.7	-7.3	73.8	88.1
4	Remove Neptune Cable	17.6	+2.6	80.8	96.1
5	No Internal NYS Transmission System Constraints	12.6	- 2.4	*	*
6	Decrease NYCA EFOR to match lowest 5 yr value	12.0	-3.0	76.9	95.0
7	Increase NYCA EFOR to match highest 5 yr value	16.2	+1.2	78.9	96

* Locational capacities are not relevant for this case.
** Locational Reserve Margin levels computed based on resulting capacity/load ratio.

NYISO IMPLEMENTATION OF THE NYCA IRM REQUIREMENT

<u>NYISO Translation of NYCA Capacity Requirements to Unforced Capacity</u>

The NYISO values capacity sold and purchased in the market in a manner that considers the forced outage ratings of individual units — Unforced Capacity or "UCAP". To maintain consistency between the rating of a unit (UCAP) and the statewide ICR, the ICR must also be translated to an unforced capacity basis. In the NYCA, these translations occur twice during the course of each capability year, prior to the start of the summer and winter capability periods.

Additionally, any LCRs in place are also translated to equivalent UCAP values during these periods. The conversion to UCAP essentially translates from one index to another, and is not a reduction of actual installed resources. Therefore, no degradation in reliability is expected. The NYISO employs a translation methodology that converts UCAP requirements to ICAP in a manner that assures compliance with NYSRC Resource Adequacy Rule A-R1. The conversion to UCAP provides financial incentives to decrease the forced outage rates while improving reliability.

<u>NYISO Implementation of a Spot Market Auction based on a Demand Curves</u>

Effective June 1, 2003 the NYISO replaced its monthly Capacity Deficiency Auction with a monthly Spot Market Auction based on three FERC-approved Demand Curves. Demand Curves are developed for Zones J, K, and the rest of NYCA. The existence of Demand Curves does not impact the determination of IRM requirements by the NYSRC.

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Appendix A

NYCA Installed Capacity Requirement Reliability Calculation Models and Assumptions

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Description of the GE-MARS Program;
Load, Capacity, Transmission, and
Outside World Models; and Assumptions

A-1 Introduction

Appendix A provides details of the modeling and assumptions for the NYCA IRM study covered in this report.

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 on the following page.

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-5 compares the assumptions used in the 2007 and 2008 IRM reports.

Figure A-1
NYCA ICAP Modeling

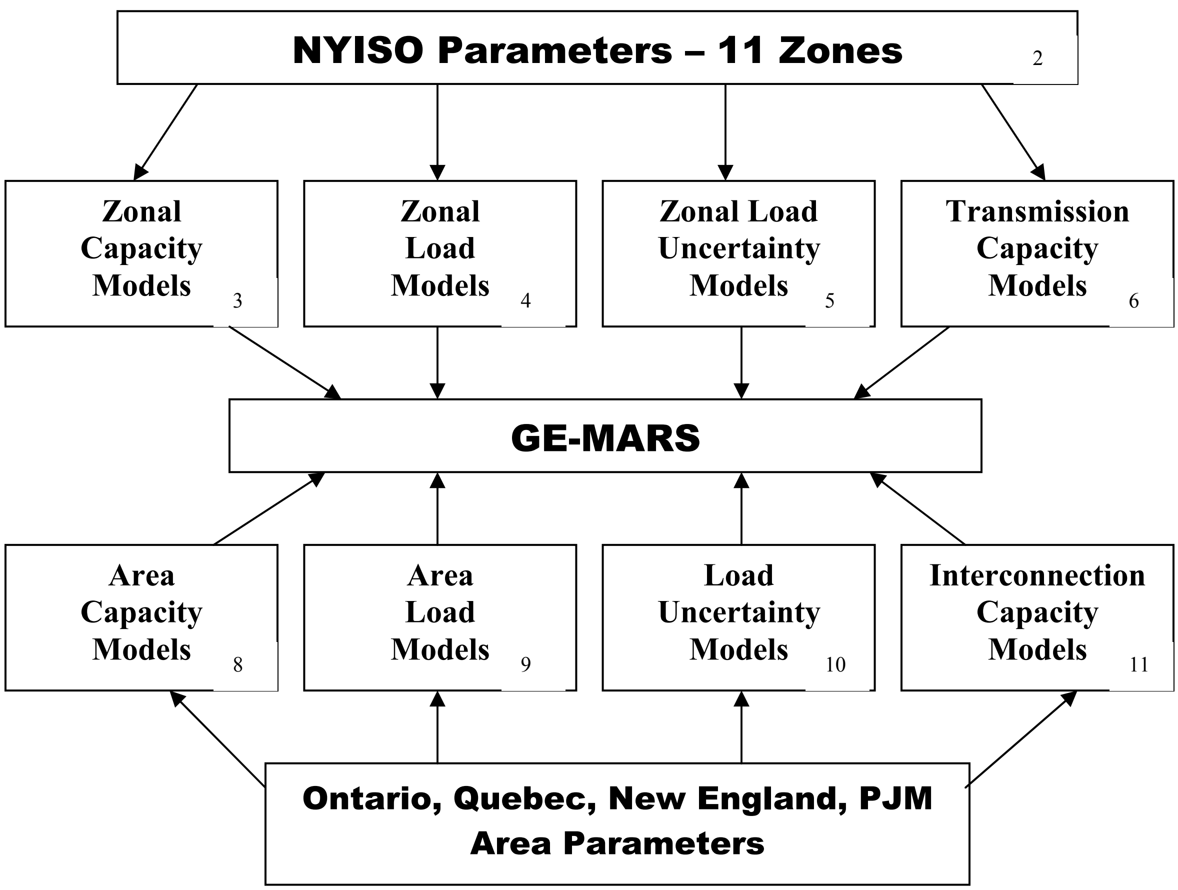


Table A-1 (Refer to Figure A-1)
Details on Study Modeling

Internal NYCA Modeling:

Figure A-1 Box No.	Name of Parameter	Description	Source	Reference
1	GE-MARS	**General Electric Multi-Area** Reliability Simulation Program		Section A-2
2	11 Zones	Load areas	Fig. A-3	NYISO Accounting & Billing Manual
3	Zone Capacity Models Emergency Operating Procedures	-Generator Models for each generating unit in Zone. -Generating Availability. -Unit Ratings. Reduces load during emergency conditions to maintain operating reserves.	GADS Data 2007 "Gold Book"* NYISO	Section A-5.3 Section A-5.4
4	Zone Load Models	Hourly loads	NYCA load shapes. NYISO peak forecasts.	Section A-5.2 33,730 MW NYISO Oct. forecast
5	Load Uncertainty Model	Account for forecast uncertainty due to weather and economic conditions.	Historical Data	Section A-5.1.1
6	Transmission Capacity Model	Emergency transfer limits of transmission interfaces between Zones.	NYISO transmission studies	Section A-5.5

External Control Area Modeling:

7	Ont., Quebec, NE, PJM control area Parameters	See the following items 8-11.		
8	External Control Area Capacity Models	Generator Models in neighboring control areas	Supplied by External Control Areas	Section A-5.7
9	External Control Area Load Models	Hourly Loads	Same as above	Section A-5.7
10	External Control Area Load Uncertainty Models	Account for forecast uncertainty due to weather and economic conditions	Supplied by External Control Areas	Section A-5.7
11	Interconnection Capacity Models	Emergency transfer limits of transmission interfaces between control areas.	Supplied by External Control Areas	Figure A-10

* "2007 Load & Capacity Data" Report issued by the NYISO.

A-2 Computer Program Used for Reliability Calculations

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 Sections A-3 and A-5.6 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-5.4).

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 to be 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 (TR) from state A to state B is defined as the number of transitions from A to B per unit of time in state A:

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

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:

TR (1 to 2) = (10 transitions) / (5000 hours) = 0.002

Table A-2
Example of State Transition Rates

Time-in-State Data		
State	**MW**	**Hours**
1	200	5000
2	100	2000
3	0	1000

Transition Data			
From State	**To State** 1	2	3
1	0	10	5
2	6	0	12
3	9	8	0

State Transition Rates			
From State	**To State** 1	2	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, as a result 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-2.1 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.

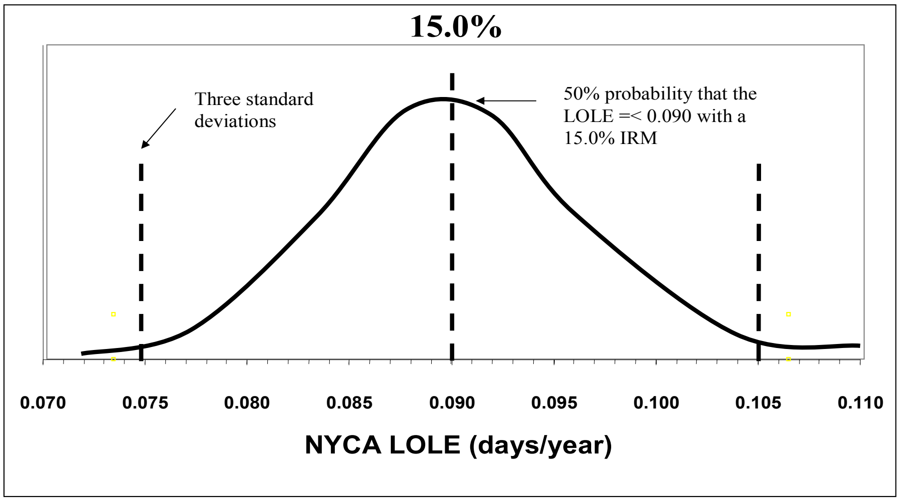
Convergence can also be expressed in terms of a confidence interval that defines the range in which you can state, with a given level of confidence that the actual value falls within the interval. For example, a range centered on the mean of three standard deviations in each direction (plus and minus) defines a confidence interval of 99.7%.

For this analysis, the Base Case required 277 replications to converge to a daily LOLE for NYCA of 0.090 days/year with a standard error of 0.05 per unit, which corresponded to an IRM of 15.0% as shown in Figure A-2. For a 99.7% confidence interval (plus and minus three standard deviations about the mean), the IRMs that would result in a NYCA LOLE of 0.075 days/year and 0.105 days/year were computed. The resulting IRM values of 14.3% and 15.8% define the % confidence interval. The statistical significance of the 14.3%, 15.0% and 15.8% numbers are a 0.15%, 50% and 99.85% probability of meeting the one in ten criterion, assuming perfect accuracy in all parameters and using a standard error of 0.05. If a standard error of 0.025 were used, the band would tighten from 14.6 to 15.4%. It should be recognized that a 15.0% IRM, with a 50% probability of meeting the one in ten LOLE criterion, is in full compliance with the NYSRC Resource Adequacy rules and criteria (see Base Case Study Results section).

Figure A-2

Confidence Interval

Based on a Standard Error of 0.05



The lines at NYCA LOLE = 0.105 and 0.075 represent 0.090 LOLE +/- 3 σ.

A-3 - Representation of the NYCA Zones

Figure A-3 on the following page depicts the NYCA Zones represented in GE-MARS.

A-4 - Conduct of the GE-MARS Analysis

The study was performed using version 2.83 of the GE-MARS software program. This is the same version as was used in the 2007 IRM study.

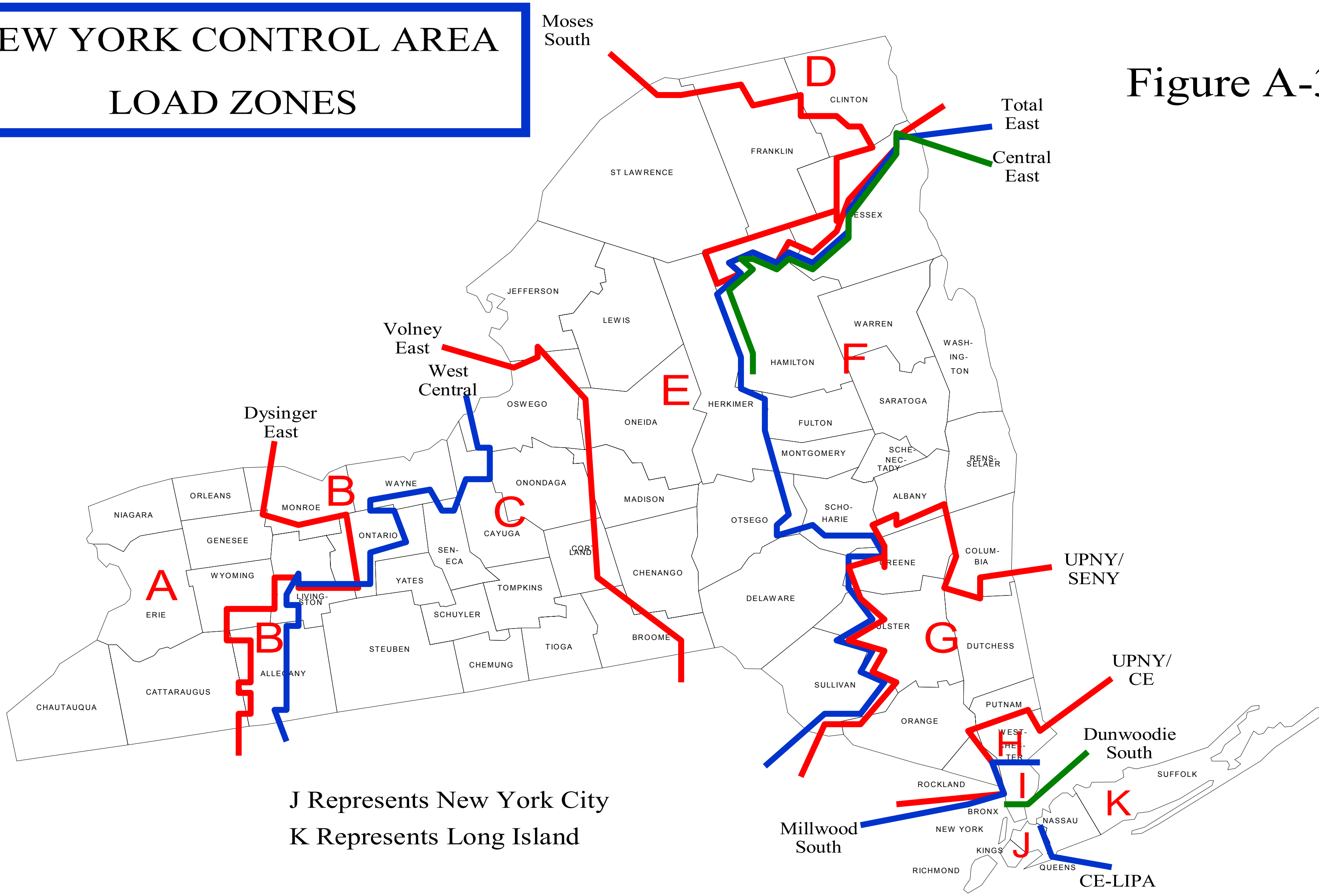
The current base case is the culmination of the individual changes made to last year's base case. Each change, however, is evaluated individually against last year's base case. The LOLE results of each of these pre-base case simulations are reviewed to confirm that the reliability impact of the change 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 then 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 Table A-3:

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.

NEW YORK CONTROL AREA LOAD ZONES

Figure A-3



J Represents New York City

K Represents Long Island

Table A-3
GE Data Scrub

	Issue	Disposition
1	Units with Zero EFORds	Identified as hydro units where derate is applied separately
2	Large Units with High EFORds	Units identified. Investigation revealed high EFORds is correct according to GADS data.
3	EFORd > 90% for Small Unit	Unit identified as correctly having large EFORd.
4	Planned Outage > 25 Weeks	Maintenance scheduled reviewed and found correct. Unit identified was small and not in critical locality
5	Incorrect limit on K - SWCT interface	Correct limit inserted
6	Record length for UNT-DERT table too long to be read	Data fit to readable length.
7	Load multipliers for UNT-DERT decrements must be entered as 'less than'.	Multipliers changed from "less than or equal to' to 'less than'.

A-4.1 - Methodology

This year's study continued to use the Unified Methodology that simultaneously provides a basis for the NYCA installed reserve requirements and locational installed capacity requirements. The following describes how the tangent 45 inflection point is calculated:

The IRM/LCR characteristic consists of two constituents; 1) a curve function ("the knee of the curve", and 2) straight line segments at the asymptotes. The curve function is represented by a quadratic (second order) curve which is the basis for the Tangent 45 inflection point calculation. Consideration of IRM/LCR point pairs remote to the "knee of the curve" may impact the calculation of the quadratic curve function used for the Tangent 45 calculation. The procedure for determining the best fit curve function used for the calculation of the Tangent 45 inflection point to define the basecase requirement is based on the following criteria summarized below:

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

– Ensure the *calculated* IRM and corresponding LCR do not violate the 0.1 LOLE criteria
– Check result to ensure consistent with visual inspection methodology used in past years studies.

This approach produced a quadratic curve function with R^2 correlation approaching 1.000 as the basis for the Tangent 45 calculation. First derivatives were calculated for the NYC and Long Island zones for each of the equations and solved for the 45 degree slope resulting in an average value of 15.0%. As shown in Table A-4, the result of approximately 15% IRM was determined for "best fit" equations based on 4 points through 9 point segments. Cases with 10 and 11 point segments produced a mathematically calculated IRM of 15.3% and 15.5% respectively, although the resulting TAN 45 is not tangent to the curve. The case with a 12 point segment produced an inflection point below the actual IRM/LCR points in violation of 0.1 LOLE criteria. Lastly, the resulting MLCR values described above were increased to the next higher whole integer. The above methodology was adopted by the NYSRC Executive Committee at the November 7, 2007 meeting and will be incorporated into the next Policy 5 revision.

Table A-4
Details of TAN 45 Derivation

# of Points		**Equation**	Resulting IRM	Resulting R^2	Violate 0.1 Criteria	Violate Visual Methodology as Used in Previous Years' Studies
4	NYC	$25.0000 * X^2 - 8.3370 * X + 1.4746$	14.9%	100.0%	No	No
	Long Island	$44.0000 * X^2 - 14.2760 * X + 2.0852$				
5	NYC	$32.2857 * X^2 - 10.5009 * X + 1.6351$	14.9%	99.9%	No	No
	Long Island	$56.5714 * X^2 - 18.0097 * X + 2.3620$				
6	NYC	$40.9286 * X^2 - 13.0332 * X + 1.8202$	14.9%	99.9%	No	No
	Long Island	$57.1429 * X^2 - 18.1771 * X + 2.3743$				
7	NYC	$33.1905 * X^2 - 10.8588 * X + 1.6679$	15.0%	99.8%	No	No
	Long Island	$49.0476 * X^2 - 15.9024 * X + 2.2150$				
8	NYC	$12.0714 * X^2 - 4.5285 * X + 1.1945$	15.1%	99.7%	No	No
	Long Island	$15.2381 * X^2 - 5.7238 * X + 1.4506$				
9	NYC	$10.2165 * X^2 - 3.9553 * X + 1.1505$	15.0%	99.6%	No	No
	Long Island	$12.7792 * X^2 - 4.9640 * X + 1.3922$				

A-5 - Input Data and Models

A-5.1 - Base Case Modeling Assumptions

Table A-5 summarizes the major assumptions used in the 2008 Study:

Table A-5
Base Case Modeling Assumptions for 2008 NYCA IRM Study

Parameter	2007 Study Modeling Assumptions	2008 Study Modeling Assumptions	Described in following section
NYCA Load Model			
Peak Load	October forecast: • 33,544 MW for NYCA • 11,775 MW for Zone J • 5,478 MW for Zone K	October forecast: • 33,730 MW for NYCA, • 11,955 MW for Zone J • 5,460 MW for Zone K	Section A-5.2
Load Shape Model	2002 Load Shape	2002 Load Shape	Section A-5.2
Load Uncertainty Model	Statewide and zonal model updated to reflect current data.	Statewide and zonal model updated to reflect current data.	Section A-5.2.1
Capacity Resources			
Generating Unit Capacities	Updated DMNC test values.	Updated DMNC test values per 2007 Gold Book.	Section A-5.3
New Generation Units	Gold Book (table III) units plus: • Prattsburgh Wind Farm - 79.5 MW (10/06) • Flat Rock Wind Power (phase 2) - 100 MW (12/06)	Gold Book (table III) units plus • Prattsburgh Wind Park - 55 MW (11/07) • Gilboa unit 2 uprate of 30 MW (6/07).	.Section A-5.3
Wind Generation Resources	Derived from hourly wind data with average Summer Peak Hour capacity factor of 11.4%	Derived from hourly wind data with average Summer Peak Hour capacity factor of approximately 11 %.	Section A-5.3
Retirements	• Huntley 65 & 66 (165 MW) • Lovett 5 (176.2 MW) • Lovett 3 (46.8 MW)	• Lovett 3, 4, 5 (404.8 MW) • Russell Station (236.4 MW) • Huntley 65 & 66 (165 MW) • Ogdensburg (76.7 MW).	Section A-5.3
Availability & Maintenance			
Forced & Partial Outage Rates	5-year (2001-05) GADS data. (Those units with less than five years data will use available representative data.)	5-year (2002-06) GADS data. (Those units with less than five years data will use available representative data.)	Section A-5.3
Planned Outages	Based on schedules received by NYISO & adjusted for history.	Based on schedules received by NYISO & adjusted for history.	Section A-5.3
Summer Maintenance	Continue with approximately 150 MW after reviewing last year's data.	Continue with approximately 150 MW after reviewing last year's data.	Section A-5.3
Gas Turbines Ambient Derate	Derate expanded to include combustion turbine portion of combined cycle units.	The derate model was updated after analyzing historical performance.	Section A-5.3
Non-NYPA Hydro Capacity Modeling	45% derating.	45% derating.	Section A-5.3

Parameter	2007 Study Modeling Assumptions	2008 Study Modeling Assumptions	Described in following section
Emergency Operating Procedures (EOPs) & Assistance			
Special Case Resources	• 1080 MW sold; • modeled as 994 MW.	• 1323 MW sold; • modeled as 1205 MW.	Section A-5.3
EDRP Resources	• 507 MW registered; • modeled as 228 MW	• 430 MW registered; • modeled as 193.5 MW	Section A-5.3
External Capacity	3085 MW total: • 1000 from HQ, • 730 from NE, • 1300 from PJM, • 55 from Ontario.	2,921 MW total: • 1200 from HQ, • 50 from NE, • 1300 from PJM, • 205 from Ontario, • 166 MW from Cedars	Based on NYISO forecast. Section A-5.3
Emergency Operating Procedures	1500 MW load relief excluding SCR and EDRP values	1503 MW load relief excluding SCR and EDRP values	Section A-5.4
Transmission System Model			
Interface Limits	Based on 2006 Operating Study, 2006 Operations Engineering Voltage Studies, 2006 Comprehensive Planning Process, and additional analysis.	Based on 2007 Operating Study, 2007 Operations Engineering Voltage Studies, 2007 Comprehensive Planning Process, and additional analysis.	Section A-5.5
New Transmission Capability	None Known	• Introduction of Millwood Capacitor bank, • Neptune line including EGC to Newbridge to Ruland Road. • Mott Haven substation. • NUSCO 1385 cable reconductoring. • Completion of Bethel to Norwalk 345Kv.	Section A-5.5.
Transmission Cable Forced Outage Rate	All existing Cable EFORs updated on LI and NYC to reflect 5 year history.	All existing Cable EFORs updated on LI and NYC (based on 2002-2006 availability with adjustment to NUSCO cable due to reconductoring).	Section A-5.5.
Unforced Capacity Deliverability Rights (UDRs)	Dummy zone in NY attached to zone K and NE with 330 MW tie and 330 MW of NE units in dummy zone (for CSC).	LIPA has notified the NYISO that the amount of UDR's for the Neptune Cable and Cross Sound Cable is confidential data.	Per transmission owner notification.
Other Modeling Considerations			
GE-MARS computer Model Version	Version 2.83	Version 2.83	Section A-2
Outside World Area Models	Updated models for PJM and NE to include zonal representations.	Updated models.	Section A-5.7

A-5.2 NYCA Load Model

Methodology for Determining the Summer IRM Peak Load Forecast

Prior to 2007, the load forecast used to develop GE-MARS runs was based on the most recent Load and Capacity (Gold Book) report, which is released in April or May of the current year. The Gold Book uses load data from the previous summer. This means that the forecast used for the IRM study had always been over one year old. Beginning last year with the 2007 IRM Study, the Executive Committee of the NYSRC requested a forecast for the IRM study year to be prepared after the most recent summer. This meant advancing the schedule for the installed capacity (ICAP) forecast, normally not released until January of the next year.

The procedure for preparing the ICAP forecast is detailed in the NYISO Load Forecasting Manual and authorized by the FERC under the NYISO tariff. It calls for a joint effort by the NYISO and participating transmission organizations in the NYISO's Load Forecasting Task Force (LFTF). In particular, the ICAP forecast is based in large part on data provided by the Transmission Owners (TOs). For the IRM forecast however, it is not possible to obtain all load data, complete the weather normalization process, and produce a forecast to meet the IRM schedule according to the procedures detailed in the manual. To meet the request of the NYSRC, the NYISO and TOs use as much data and results as possible from the TOs. To further aid this process, the NYISO also requests an expedited updated economic forecast from Moody's Economy.com. This economic forecast is now provided in August one month earlier than in previous studies.

Using these abbreviated methods, the NYISO and the TOs jointly produced and reviewed a forecast in September 2007 they recommended for use in the 2008 IRM study. This forecast was based upon weather-normalized peaks load in 2007 for each of the TOs, NYPA, and other NY municipalities for the hour of the NYISO coincident peak. The 2008 forecast was produced by applying regional load growth factors (RLGFs) to each TO's weather-normalized peak. Where possible, the RLGFs were based upon new economic forecasts prepared by the TOs. Otherwise, the most recent data from Economy.com is used to adjust the RLGFs used in the prior ICAP forecast.

The final result is a peak load forecast based upon the most recent data available for the IRM study that maintains the schedule for the IRM study, as shown in Table A-6 on the following page.

Table A-6
2008 NYCA Area Peak Load Forecast

Summary of 2006 & 2007 Results						
Transmission District	**2006 Weather Adjusted MW**	**2007 RLGF - Forecast**	**2007 ICAP Forecast - MW**	**2007 Weather Adjusted MW**	**MW Over/ Under**	**2007 RLGF - Actual**
Central Hudson	1,177	1.0240	1,205	1,200	-5	1.0195
Con-Edison	13,408	1.0168	13,633	13,608	-25	1.0149
LIPA	5,256	1.0126	5,322	5,312	-10	1.0107
Niagara Mohawk	6,719	1.0000	6,718	6,705	-13	0.9979
NYPA	534	1.1020	588	587	-1	1.0993
NYSEG	3,177	1.0125	3,217	3,211	-6	1.0107
O&R	1,095	1.0330	1,132	1,130	-2	1.0320
RGE	1,626	1.0035	1,632	1,629	-3	1.0018
NYCA Total	**32,992**	**1.0138**	**33,447**	**33,382**	**-65**	**1.0118**

2008 Forecast for NYSRC Installed Reserve Margin Study					
Transmission District	**2007 Weather Adjusted MW**	**2008 RLGF**	**NYSRC 2008 Forecast - MW**	**Difference in MW**	**2008 Gold Book Forecast**
Central Hudson	1,200	1.0190	1,223		
Con-Edison	13,608	1.0170	13,839		
LIPA	5,312	1.0081	5,355		
Niagara Mohawk	6,705	0.9979	6,691		
NYPA	587	1.0000	587		
NYSEG	3,211	1.0107	3,245		
O&R	1,130	1.0250	1,158		
RGE	1,629	1.0018	1,632		
NYCA	**33,382**	**1.0104**	**33,730**	**-141**	**33,871**

Locality Peaks	NYSRC 2008 Forecast - MW	Difference in MW	2008 Gold Book Forecast
New York City	11,955	-20	11,975
Long Island	5,460	-25	5,485

Load Shape Analysis

The 2008 IRM study was performed using a load shape based on 2002 actual values. The 2002 load shape was compared to load shapes from 1999 through 2006. The conclusion reached this year was the same as in previous years - that the 2002 load shape is best suited for the IRM study.

Zonal Load Distribution

From 1995 to 2000, the peak loads increased faster downstate than upstate. But since 2000, the zonal shares have been virtually constant. Table A-7 presents load trends from 1995 to 2006. The chart shows the three-year moving average of each region's share of coincident peak demand. There is no discernible trend since 2000. The peak load share upstate is holding steady at 50%. The zonal share is also sensitive to the hour of the peak. A peak later in the day will tend to increase the share in Zone J and decrease it in the upstate zones. But the hour of the peak changes randomly from year to year, making it more difficult to identify trends with respect to this factor.

Table A-7
Relative Zonal Shares of Coincident Peak Demand
Three-Year Moving Average of Shares

Year	J	K	J-K	A-I
1995	32%	13%	46%	54%
1996	32%	13%	46%	54%
1997	33%	14%	47%	53%
1998	33%	14%	47%	53%
1999	34%	15%	49%	51%
2000	34%	15%	50%	50%
2001	34%	15%	50%	50%
2002	34%	16%	50%	50%
2003	34%	16%	50%	50%
2004	34%	16%	50%	50%
2005	34%	16%	50%	50%
2006	34%	16%	50%	50%

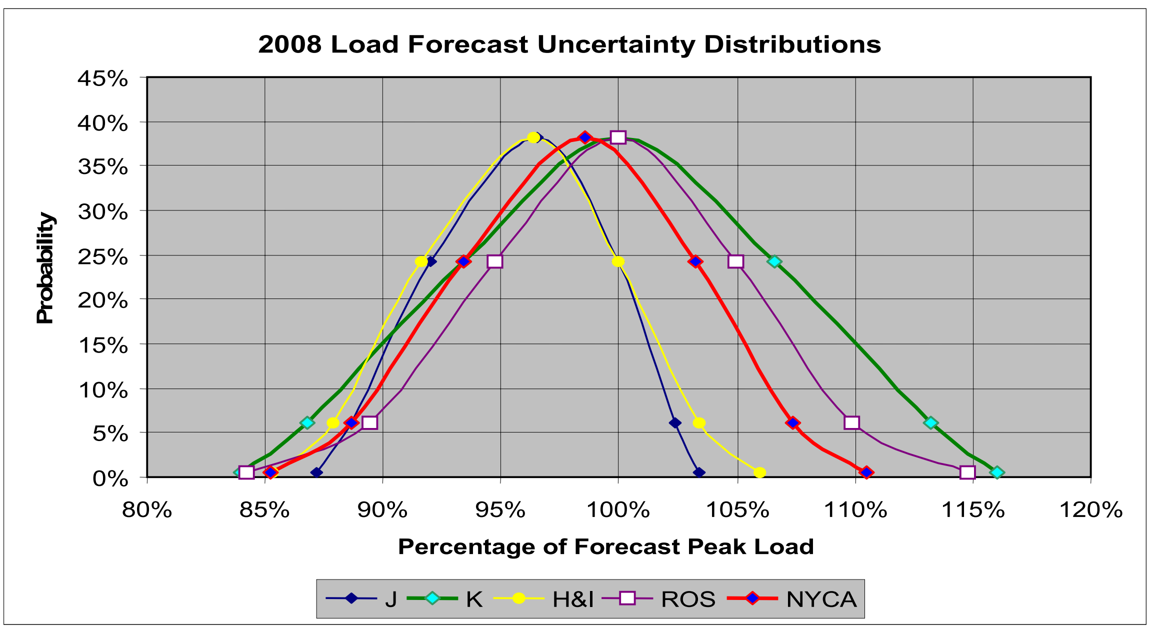
A-5.2.1 Zonal Load Forecast Uncertainty

For 2008, new load forecast uncertainty models were provided by Consolidated Edison (Con Edison) (for Zones H, I and J) and LIPA (for Zone K). Additional models were developed by the NYISO for Zones A-G. The results of these models are presented in Table A-8. 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-4.

Table A-8
2008 Load Forecast Uncertainty Models

Multiplier	Zones H & I	Zone J	Zone K	NYCA Net
0.0062	0.853	0.871	0.839	0.841
0.0606	0.878	0.886	0.868	0.894
0.2417	0.916	0.919	0.934	0.947
0.3830	0.964	0.964	1.000	1.000
0.2417	1.000	1.000	1.066	1.049
0.0606	1.033	1.023	1.131	1.098
0.0062	1.059	1.033	1.160	1.147

Figure A-4



The Con Edison (Zone J) model reflects the fact that the load forecast used for Zone J has a 1 in 3 instead of 1 in 2 probability of occurrence. The LI (Zone K) model is only marginally different than that used in 2007. The approach developed in 2006 for the remaining zones is maintained in the IRM 2008 study. The models for Zones A to I were developed by estimating weather response equations, taking care to examine the behavior both below and above design conditions.

This work was reviewed by the LFTF. The weather response equations were used to estimate uncertainty distributions for these zones, and to assess the load forecast uncertainty models provided to the NYISO by Con Edison and LIPA.

A-5.3 NYCA Capacity Model

2007 "Gold Book" Changes:

The capacity model input to GE-MARS incorporates the several types of resource capacity used to serve load in the NYCA. The following were changes made to the existing capacity shown in Table III-2 of the "2007 Load and Capacity Data" (also known as "The Gold Book"):

- **Retirements:**
  - Huntley 65 & 66 — 165 MW — Zone A
  - Lovett 3, 4, & 5 — 404.8 MW — Zone G
  - Russell Station — 236.4 MW — Zone B
  - Ogdensburg — 76.7 MW — Zone E

- **New Units: (Units installed during 2007)**
  - Gilboa Station 2 uprate — 30 MW — Zone F

- **Planned Units for 2008:**
  (These units had a signed interconnection agreement by August 1, 2007.)
  - Prattsburgh Wind Park — 55 MW — Zone C

The section below describes how each resource type is modeled in GE-MARS.

Generating Units:

The capacity model includes all NYCA generating units, including new and planned units, as well as units that are physically outside New York State. This model requires the following input data:

Unit Ratings:

With the exception of wind units, the rating for each 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. Wind units are rated at their nameplate, or full rated value, in the model. The 2007 NYCA Load and Capacity Report, issued by the NYISO, is the source of those generating units and their ratings included on the capacity model.

Unit Performance:

With the exception of wind units, performance data for 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 2008 IRM Study. (See Figure A-5)

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

The unit forced outage states for the majority of the large steam units were obtained from the five-year average NERC-GADS outage data collected by the NYISO for the years 2002 through 2006. 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.

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 component is obtained from the generator owners, and where necessary, extended so that the scheduled maintenance period equals the historic average using the same five year period used to determine EFORd averages. Figure A-8 provides a graph of scheduled outage trends over the 1993 through 2006 period for the NYCA generators.

Wind generators are modeled as an hourly load modifier. The output of the unit varies between 0 and the DMNC value based on wind data collected near the Plant sites during 2002. The 2002 hourly wind data corresponds to the 2002 hourly load shape also used in the model. Characteristics of this data indicate an overall 30% capacity factor with a capacity factor of approximately 11% during the summer peak hours. A total of 436 MW of installed capacity associated with wind generators is included in this study.

Figure A-5

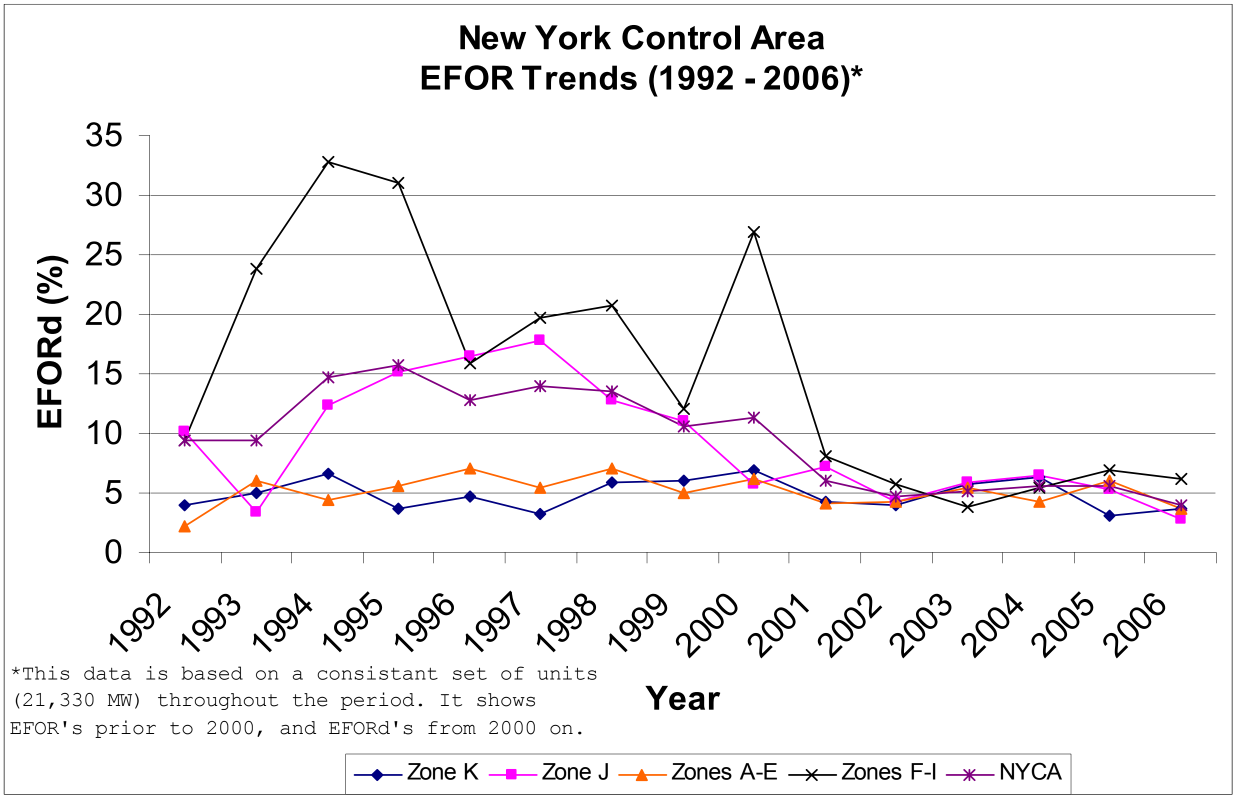


Figure A-5 provides a graph of Equivalent Forced Outage Rates under Demand (EFORd). The graph presents unit weighted averages for four areas within the NYCA along with a NYCA total aggregate.

Equivalent Availability:

The equivalent availability factor accounts for forced, partial, scheduled, and maintenance outages. Figure A-6, which is based on NERC-GADS data for New York units, shows that there is a continued trend of improved reliability.

Figure A-7 provides NERC-GADS data industry-wide. The continued improved availability is similar to that experienced in the NYCA.

Figure A-6

NYCA EQUIVALENT AVAILABILITY

BASED ON NERC-GADS DATA FROM 1982 – 2006

ANNUAL WEIGHTED AVERAGES FOR NUCLEAR, COAL, OIL & GAS, AND COMBUSTION TURBINES

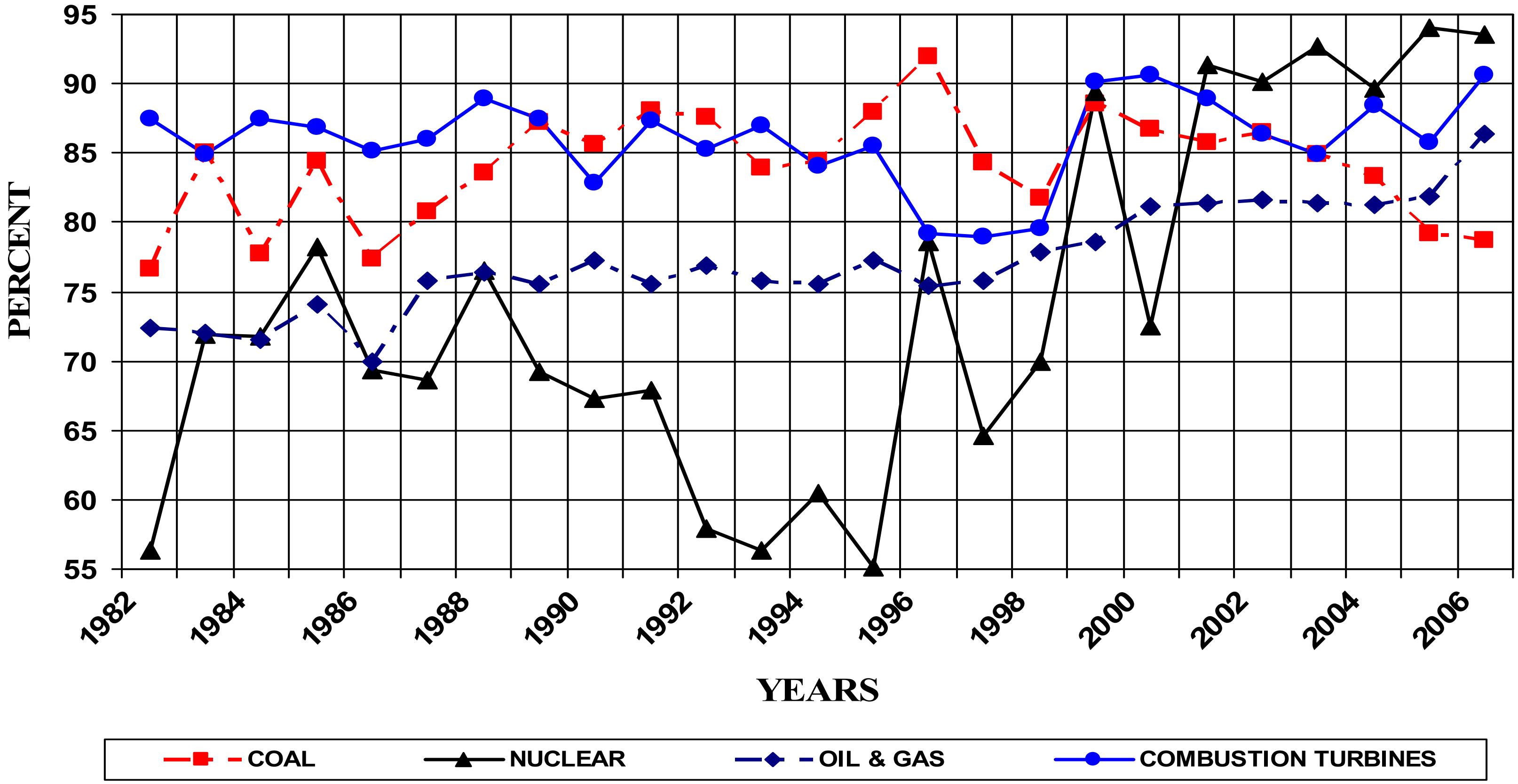


Figure A-7

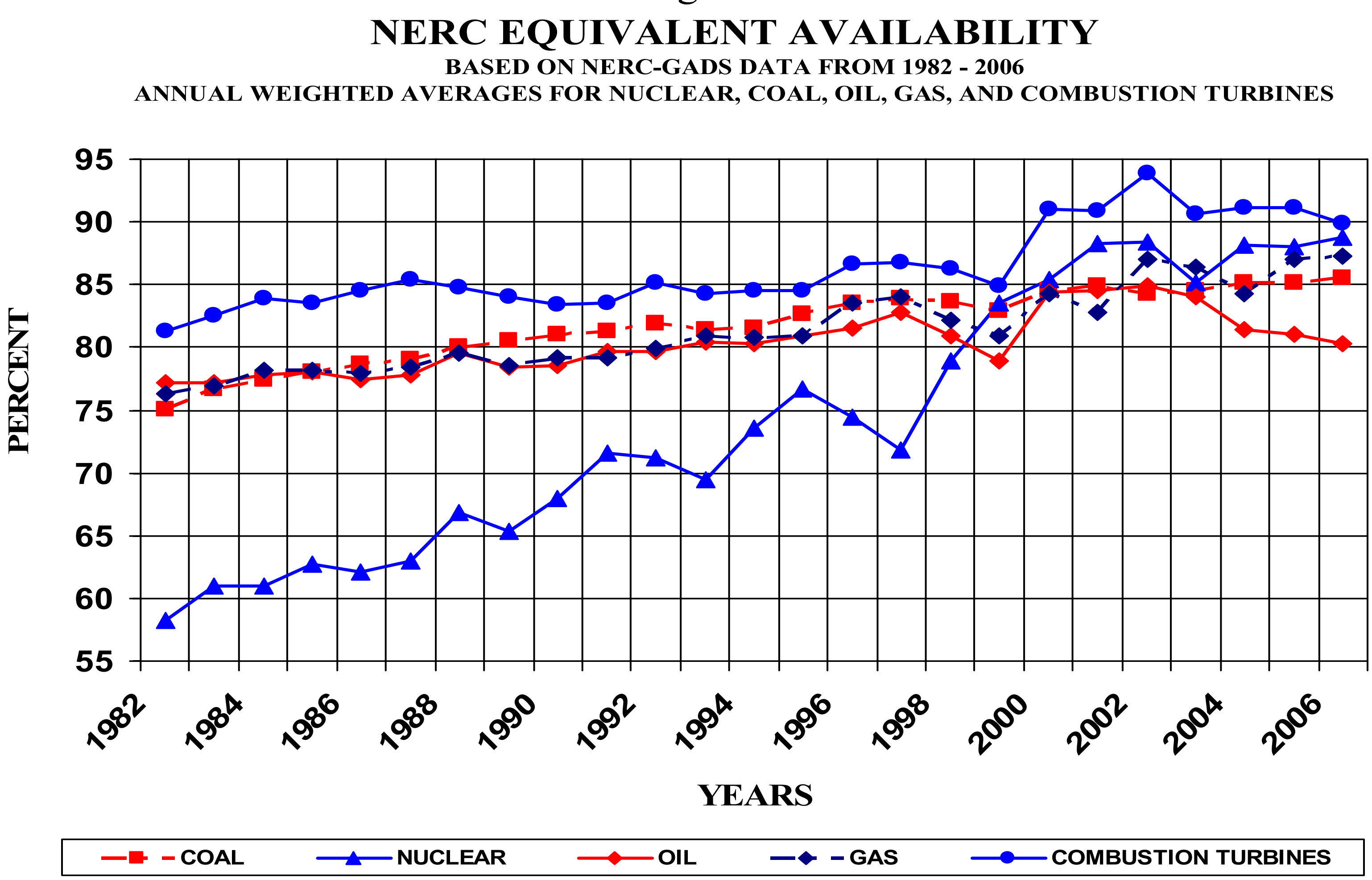

NERC EQUIVALENT AVAILABILITY
BASED ON NERC-GADS DATA FROM 1982 - 2006
ANNUAL WEIGHTED AVERAGES FOR NUCLEAR, COAL, OIL, GAS, AND COMBUSTION TURBINES
95
90
85
80
75
70
65
60
55
PERCENT
1982
1984
1986
1988
1990
1992
1994
1996
1998
2000
2002
2004
2006
YEARS
COAL
NUCLEAR
OIL
GAS
COMBUSTION TURBINES

Figure A-8

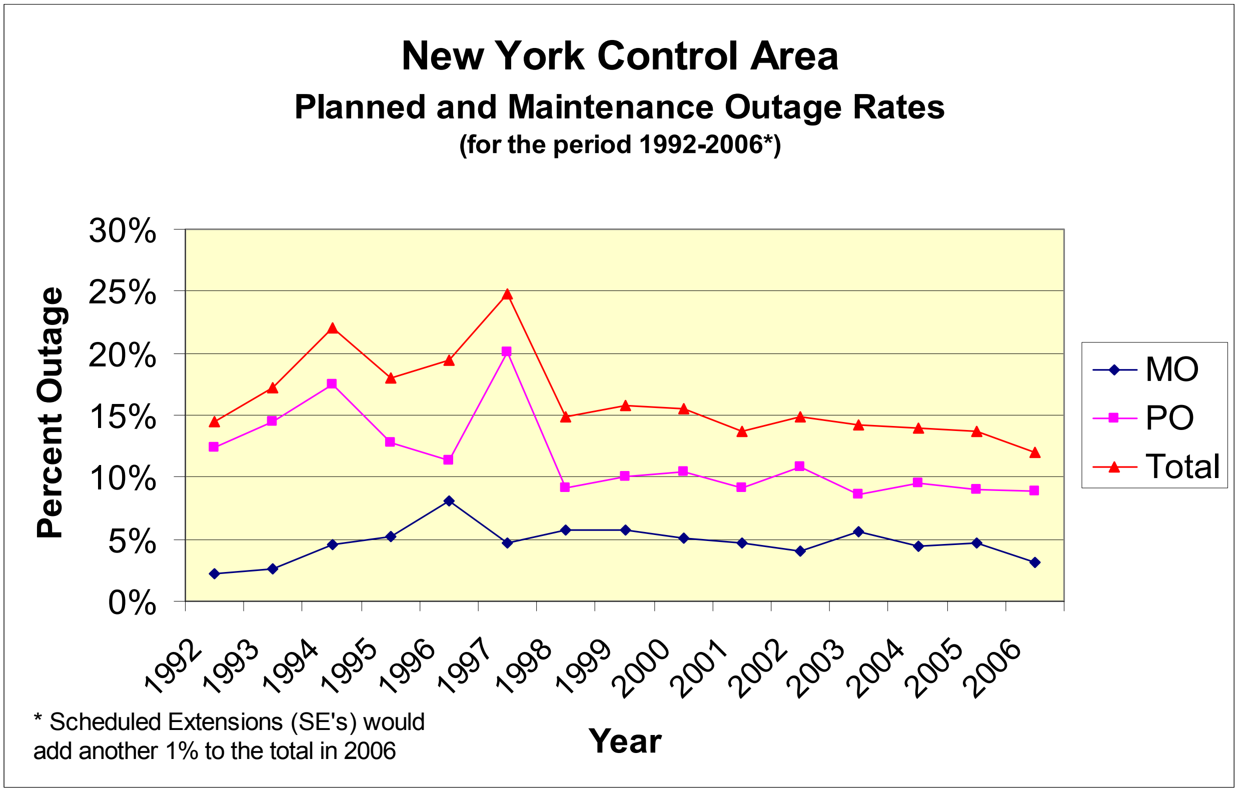
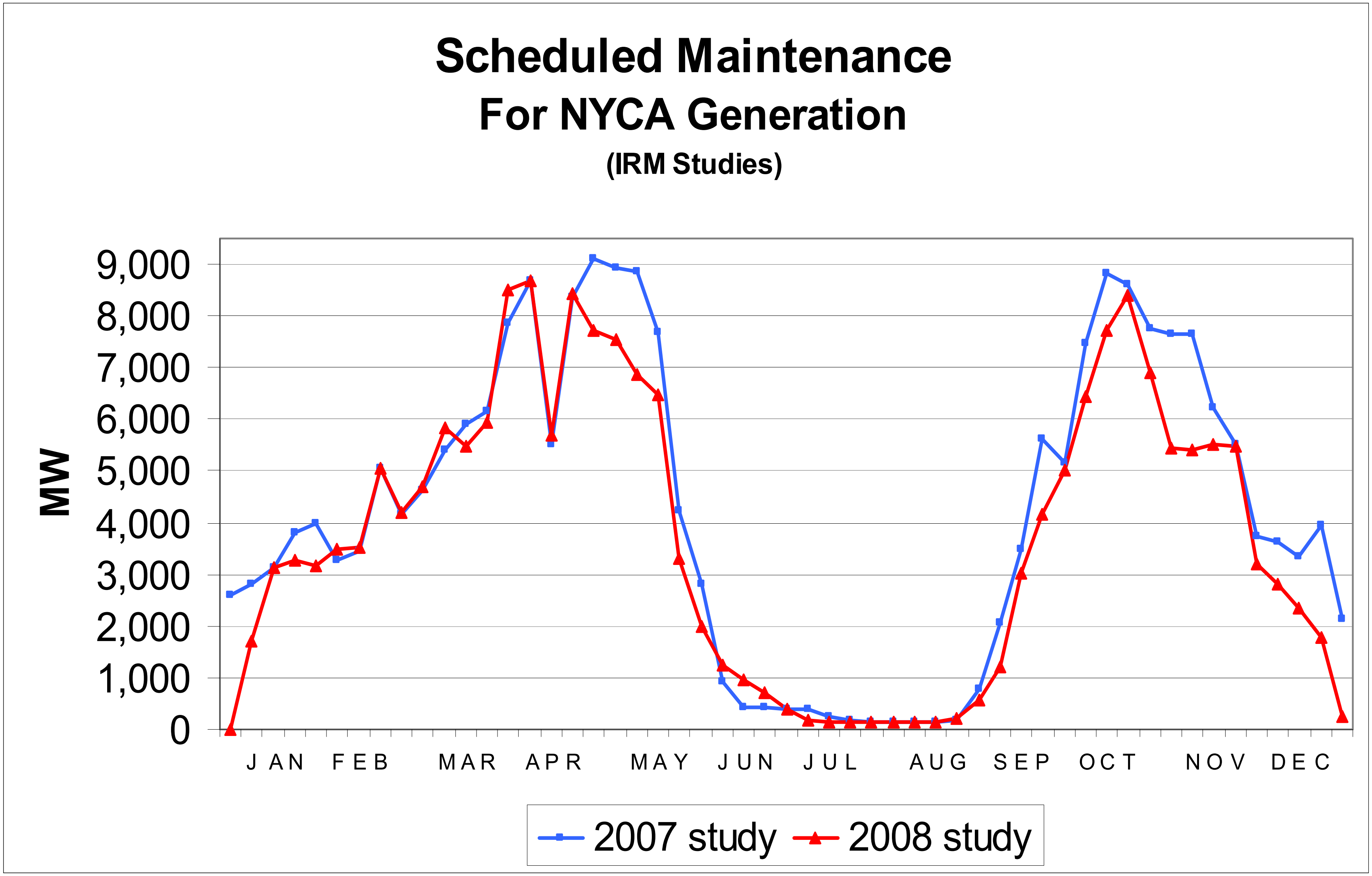


Figure A-8 shows the historic percentage of planned and maintenance outage hours for the years 1992 through 2006.

Figure A-9 shows the amount of capacity assumed to be scheduled out in the 2007 and 2008 studies.

The planned outages in the current study over the 2008 summer period are approximately 150 MW.

Figure A-9


Scheduled Maintenance
For NYCA Generation
(IRM Studies)
MW
9,000
8,000
7,000
6,000
5,000
4,000
3,000
2,000
1,000
0
JAN
FEB
MAR
APR
MAY
JUN
JUL
AUG
SEP
OCT
NOV
DEC
2007 study
2008 study

Combustion Turbine Units:

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 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.

Review of the simple cycle combustion turbine data, however, has led the NYISO to introduce to the model what is termed a bias. The NYISO plans to extend this analysis in the future to include other capacity limited resources. Although this analysis indicates a bias at design temperatures, it also shows an approximate 1/3rd reduction from the 2007 IRM study, in the amount of correction occurring at higher temperatures. The net effect of replacing the 2007 IRM Study's simple cycle combustion turbine derate model with this year's updated model is a slight reduction in LOLE. An 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 at www.nyiso.com.

The derate does not affect all units because many of the new units are capable of generating up to 88 or 94 MW but are limited by permit to 79.9 MW, so they 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.

Hydro Units:

The Niagara and St. Lawrence hydroelectric projects are modeled with a probability capacity model based on historic water flows and unit performance. The remaining 1,040 MW of hydro facilities are simulated in GE-MARS with a 45% hydro derate model, representing deratings in accordance with recent historic hydro water conditions.

Special Case Resources (SCRs) and Emergency Demand Response Program (EDRP):

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.

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.

For this year's study the NYISO has recommended that SCRs be modeled as a 1,323 MW EOP step, discounted to 1205 MW in July and August (and further discounted in other months proportionally to the monthly peak load). Prior to this study year, the discount was applied to all zones equally. Now, with the obtainment of historic zonal performance, the discount varies on a zonal basis. Of the 1205 MW of SCRs modeled, 110 MW are generators that may be subject to DEC emission restrictions. Because of these restrictions, those units were modeled to only be available in the summer months for a total of approximately 30 hours. SCR Numbers for 2008 are net of retirements of Holtsville and Wading River truck mounted diesel generating units.

EDRPs are modeled as a 193.5 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 based on actual experience from the forecast registered amount of 430 MW.

External Installed Capacity from Contracts:

An input to the study is the amount of NYCA installed capacity that is assumed located outside NYCA. Some of this capacity is grandfathered. The balance of the contracts are based on a NYISO forecast that reflects historical contracts and current contractual activity.

The NYISO has recommended that the following inter-area capacity transactions to be modeled in this study:

The base case assumes the following summer external ICAP: 205 MW from Ontario, 1200 MW from HQ, 50 MW from New England, 166 MW from Cedars and 1300 MW from PJM. This totals 2,921 MW of expected summer external ICAP.

All firm sales are modeled as listed in the 2007 Gold Book for the year 2008.

In calculating the IRM, all sales are subtracted from the Installed capacity. Purchases are not included.

A-5.4 Emergency Operating Procedures (EOPS)

There are many steps that the system operator can take in an emergency to avoid disconnecting load. The steps listed in Table A-9 were provided by the NYISO based on experience.

Table A-9
Emergency Operating Procedures

Step	Procedure	Effect	MW Value
1	Special Case Resources (SCRs)	Load relief	1,323 MW*
2	Emergency Demand Response Programs (EDRPs).	Load relief	430 MW**
3	5% manual voltage Reduction	Load relief	151 MW
4	Thirty-minute reserve to zero	Allow operating reserve to decrease to largest unit capacity (10-minute reserve)	600 MW
5	5% remote voltage Reduction	Load relief	530 MW***
6	Voluntary industrial curtailment	Load relief	134 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	1200 MW
10	Customer disconnections	Load relief	As needed

* *The SCR's are modeled as 1,323 MW, however they are discounted to 1,205 MW in July and August and further discounted in other months*

** *The EDRPs are modeled as 430 MW discounted to 193.5 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. The associated MW value is based on a forecast 2008 peak load of 33,730 MW. .*

The above values are based on a NYISO forecast that incorporates 2006 operating results. This forecast is applied against a 2008 peak load forecast of 33,730 MW. The above 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 help that is provided by EOPs related to load, such as voltage reduction, will vary with the load level.

A-5.5 Transmission Capacity Model

Introduction

The NYCA is divided into 11 Zones. The boundaries between Zones and between adjacent Control Areas are called interface ties. These ties are used in the GE-MARS model to allow and limit the assistance among NYCA Zones and adjacent control Areas. While the NYCA transmission system is not explicitly modeled in the GE-MARS program, a transportation algorithm is utilized with limits on the interface ties between the Areas and Zones represented in the model. Interface tie groupings and dependent interface tie limits have been developed such that the transmission model closely resembles the standard eleven-Zone NYCA model. The interface tie limits employed are developed from emergency transfer limits calculated from various transfer limit studies performed at the NYISO and refined with additional analysis specifically for the GE-MARS representation. The new topology and interface limits are shown in Figure A-10.

The interface tie limits used in the 2007 IRM study were reviewed to assess the need to update the transfer limits and topology resulting from the changes to a multi area representation for PJM and New England and to reflect results from more recent studies. The Summer 2006 and 2007 Operating Study Reports, the 2004, 2005 and 2006 Area Transmission Reviews, the Reliability Needs Assessment (RNA) in the 2007 Comprehensive Reliability Planning Process, and SRIS reports were reviewed to update the transfer limits. Databases from the 2008 RNA were also used.

When the results in the above reports were not sufficient to make an assessment, additional analysis was done with these databases, and/or other studies were performed and/or referenced. Transmission Owner input and study results were also utilized. Input from neighboring regions on internal constraints was also evaluated.

Changes in Topology and Interface Groupings

The most significant change in the topology was the implementation of a new interface between PJM and Long Island to reflect the operation of the new PJM to Long Island Neptune DC tie. In addition, two new interface groupings were created, the first being a grouping of ties from PJM East to G and J to reflect simultaneous limits arising from PJM East internal constraints. Another grouping is the addition of the PJM-LI tie with the recent LI SUM to capture internal limits of the LI system for exports from western Long Island to NYC and Westchester. These internal limits are a function of generator availability and DC line flow. Appropriate nomograms were developed as per Table A-10.

Changes in Thermally Limited Interfaces

The interface limit for I to J was increased from 3700 MW to 3925 MW based on recent studies performed by Con Edison and the NYISO. This increase in limit was due to an increase in ratings, using MVA ratings for all circuits, and better flow balancing of the circuits comprising the interface. The installation of the Millwood Capacitor bank and reactor bypass restores the voltage limit to greater than the thermal limit so that the thermal limit is controlling. Replacement of Breaker 14 in the Gowanus 345 kV Station will allow the series reactors in the Farragut-Gowanus feeders to be by-passed.

With the advent of the modified UPNY / SENY Grouping and the new New England to New York Interface Grouping, the New England to SENY grouping was removed and the individual limits on Rest of NE to F and Rest of Connecticut to G were raised to their individual thermal limits.

Cable Interfaces

Failure rates for overhead lines and underground cables are similar but the repair time for an underground cable is much longer. Therefore, forced transmission outages are included in the GE-MARS model for the underground cable system from surrounding Zones entering into New York City and Long Island. The GE-MARS model uses transition rates between operating states for each interface, which are calculated based on the probability of occurrence from the failure rate and the time to repair. Transition rates into the different operating states for each interface are calculated based on the individual make-up of each interface, which includes failure rates and repair times for the cable, and for any transformer and/or phase angle regulator on that particular cable.

For the Con Edison system, the transition rates were calculated based on five year historical failures of their entire system of underground cables, transformers, and phase angle regulators that are the three major components of the cable interface system into New York City. The failure rates and repair rates for transformers, and phase angle regulators were calculated by voltage classification, and the cables' failure rates and repair rates were calculated by voltage classification and on a per-mile basis. Typically, the larger the cable and equipment population included in the study, the better the results are in predicting the future performance of the underground electric system.

Once a failure rate and a repair time are created for each component, they are combined to form a single cable system model for each cable. Each single cable system model is then combined together with the other single cable system models that make-up that particular interface to obtain a composite interface model. This provides a conservative estimated transition rate for each of the three cable interfaces into New York City.

The EFORd calculated from the transition rates of the three transmission interfaces into New York City reveal a slight decrease in the availability of all three interfaces.

The weighted average EFOR for all six cables improved from 2.22% to 2.08% while the weighted average for the three internal cables (not including Neptune HVDC cable) worsened from 1.32% to 1.45%

Interconnection Support during Emergencies

Base case assumptions considered the full capacity of transfer capability from external Control Areas (adjusted for grandfathered contracts and estimated external capacity purchases) in determining the level of external emergency assistance.

Table A-10
Interface Limit Changes for 2008 IRM

Interface Name		2007 Limit	2008 Limits, Base Case	Comments
PJM Interfaces		***Three Area***	***Maintain Three Area, RECO Load Treatment***	***PJM studies on load deliverability and assessment at NYISO request last year.***
PJM Cent to East	+ -	6000 6000	6500 6500	PJM Update
PJM East to G	+	500	500	Reflects Internal PJM Constraints For simultaneous and RECO load
	-	2000	2000	Review of Limits in New York
PJM East to J	+	600 – 1200, PJM unit	600 – 1200, PJM unit sensitive	Reflects Internal PJM Constraints and NYC Constraints
	-	0	0	No Change
PJM East to K	+		660 MW	Modeled
	-		660 MW	Both Directions
Joint PJM to G and J	+ -		1500 2000	Reflects Internal PJM Constraints, Simultaneous and RECO load
New England Interfaces		***Five Area***	***Maintain Five Area Representation***	
Northport Tie		286,143, 0	286, 200	Update Unit Nomogram by 200 MW i.e., drops to 200 MW both NWLK Units Out
New York Interfaces		***Eleven Area***	***Maintain Eleven Area Representation***	
Astoria West	+		200, 30 Unit Sensitive	Lock out of 3 GTs if AW units avail.
LI Sum,K-J Joint with PJM-LI Neptune HVDC Unit Sensitivity	-	530, 420	576, 486	Joint Con Edison and LIPA Update
			306, Neptune Zero Flow 576, Neptune Full into LI No impact on K to J modeled	PJM to LI DC Out or reduced flow, Add PJM-LI interface into grouping with LI sum for a new interface grouping.
			Reduction of LI-Sum and K to J	LI Unit Nomogram, Units Lumped for Simplification.
I into J	+	3700	3925	Updated Ratings, Power Flow Analysis with MVA ratings, and improved flow balancing
Simultaneous J Import			Sum of All Previous Ties into J	Interface is for monitoring
Updates to Transfer Limits to Reflect Hudson Valley Voltage Studies				
UPNY / SENY Group	+			Study results indicate that the new Cap bank at Millwood with NYC and PJM system changes Results in no need to update
	-			
UPNY / CE	+			
	-			

A) **Astoria West** - Unit Sensitive Model, Four Astoria West GTs are in a Separate Area, with a unit sensitive limit combined with a load level of 10,250 in Zone J:

- Starts at 200 MW, reduces to 30 MW for the following Condition Sets:

  a) All Three NYPA CC Units are available and two or three out of Astoria 3, 4, 5. This gives Four Condition sets for the combinations.

B) **LI Sum DC Tie** – Implemented to capture limitations on flows from Western Long Island to Zones I and J when the PJM to LI DC tie is out of service or flows are limited to less than full rating. An interface grouping is constructed to represent this simultaneous limitation.

LI Sum DC Tie = I to K + J to K + .4 K to PJM East

Derivation of 0.4 coefficient: Analysis was performed to determine the transfer limit at the DC at full output and zero output and a linear relationship was assumed:

(576 MW – 306 MW) / 660 MW = 0.4

Limits developed for this grouping are effective only for the Long Island west direction. When flows are from PJM to Long Island, the flows on K to J and K to I can be higher than 306, up to the present 576 MW limit.

C) **Dynamic Transfer Limit for Western LI export limit that is dependent on Western Long Island Generation availability**. Since there are over twenty units ranging in size from 14 MWs to 195 MWs in Western Long Island, only the large units are included in the Unit Status List (greater than 100 MW).

From study results, reducing Barrett, Far Rockaway and Glenwood generation by 429 MWs leads to a 393 MW reduction in the Western LI export limit and a reduction in the K to J (Jamaica Export) limit of 160 MW, giving a ratio of approximately .91 and .37, respectively. The reduction occurs primarily with deliveries to Valley Stream and then to Jamaica, so the focus is on units affecting this area. Since Far Rockaway 4 (110 MW) is downstream of Valley stream, its impact is assumed to be one for one.

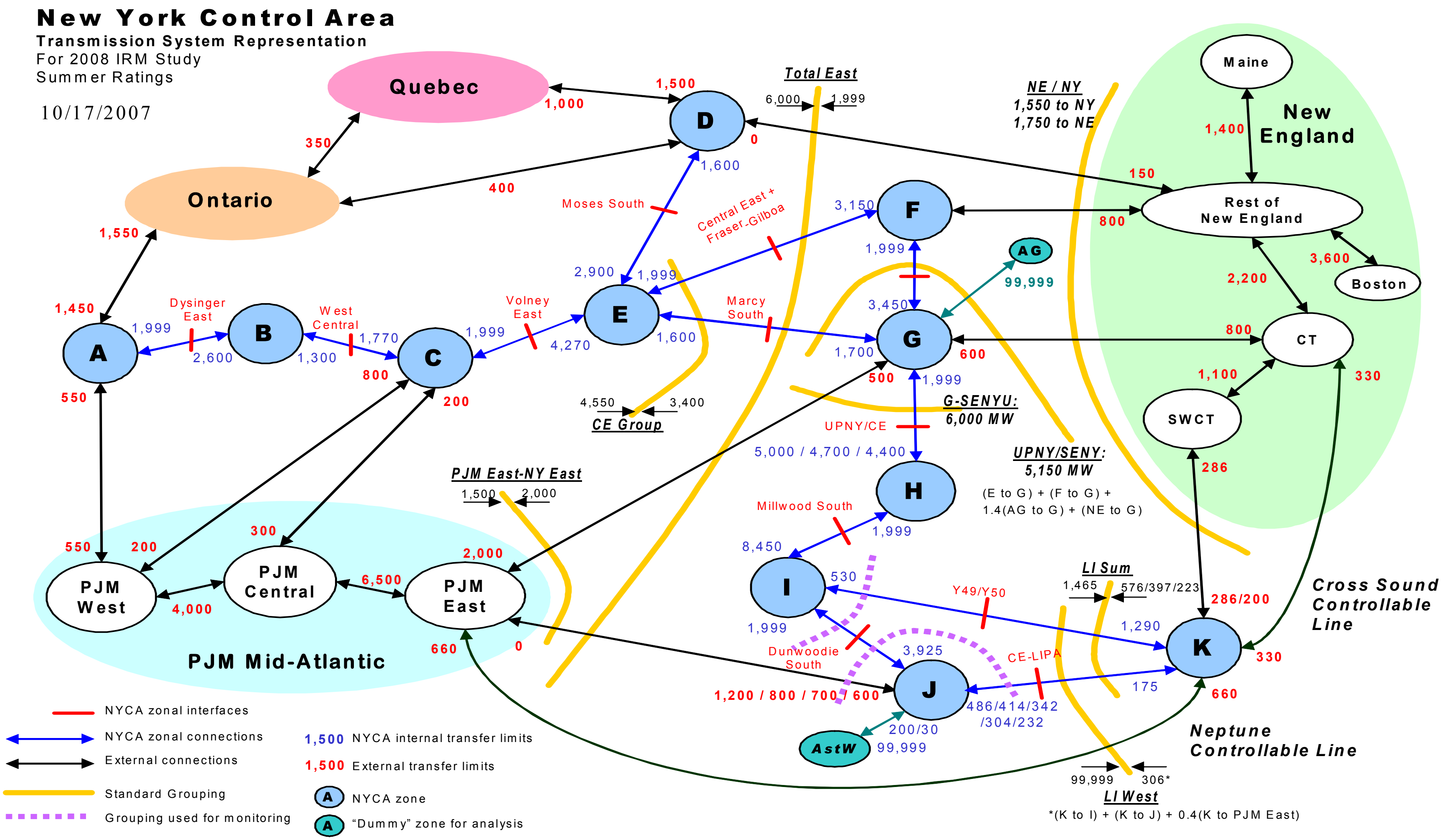
Impacts Interface K to J (Jamaica Export) and LISUM). Begin at 486 MW, LISUM 576 MW

Grouping the Units to minimize number of dynamic transfer limit tables:

a) Grouping: BARS01, BARS02
   One Unavailable Reduce by 72 MW, 179 MW, Two Unavailable Reduce by 144 MW, 353 MW

b) FROCS4 always Unavailable, then combined with:
   BARS01, BARS02 Unavailability, Reduce Only K to J
   One Unavailable Reduce by 182 MW, Two Unavailable Reduce by 254 MW

Figure A-10


New York Control Area
Transmission System Representation
For 2008 IRM Study
Summer Ratings
10/17/2007
Quebec
Ontario
New England
Maine
Rest of New England
Boston
CT
SWCT
PJM West
PJM Central
PJM East
PJM Mid-Atlantic
A
B
C
D
E
F
G
H
I
J
K
AG
AstW
Total East
6,000
1,999
NE / NY
1,550 to NY
1,750 to NE
Moses South
Central East + Fraser-Gilboa
Dysinger East
West Central
Volney East
Marcy South
CE Group
4,550
3,400
G-SENYU:
6,000 MW
UPNY/CE
UPNY/SENY:
5,150 MW
(E to G) + (F to G) + 1.4(AG to G) + (NE to G)
PJM East-NY East
1,500
2,000
Millwood South
Dunwoodie South
Y49/Y50
CE-LIPA
LI Sum
1,465
576/397/223
LI West
99,999
306*
*(K to I) + (K to J) + 0.4(K to PJM East)
Cross Sound Controllable Line
Neptune Controllable Line
5,000 / 4,700 / 4,400
1,200 / 800 / 700 / 600
486/414/342 /304/232
286/200
NYCA zonal interfaces
NYCA zonal connections
External connections
Standard Grouping
Grouping used for monitoring
1,500 NYCA internal transfer limits
1,500 External transfer limits
NYCA zone
"Dummy" zone for analysis

A-5.6 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-5.7 Outside World Load and Capacity Models

NYCA reliability largely depends on emergency assistance from its interconnected Control Areas in NPCC and PJM, based on reserve sharing agreements with the Outside World Areas. Load and capacity models of the Outside World Areas are therefore represented in the GE-MARS analyses. The load and capacity models for New England, Ontario, PJM, and Quebec are based on data received from the Outside World Areas, as well as NPCC sources.

The primary consideration for developing the final load and capacity models for the Outside World Areas is to avoid over-dependence on the Outside World Areas for emergency capacity support. For this purpose, a rule is applied whereby either an Outside World Area's LOLE cannot be lower than 0.100 days/year LOLE, or its isolated LOLE cannot be lower than that of the NYCA. In other words, the neighboring Areas are assumed to be equally or less reliable than NYCA. Another consideration for developing models for the Outside World Areas is to recognize internal transmission constraints within the Outside World 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.

The year 2002 is used in this study for both the NYCA and the Outside World Area load shapes. In order to avoid over-dependence from emergency assistance, the three highest summer load peak days of the Outside World 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.

The EOPs were removed from the Outside World Areas to avoid the difficulty in modeling the sequence and coordination of implementing them. This is a conservative measure.

The assistance from Reliability First Corporation (RFC), with the exception of PJM Mid Atlantic, and the Maritime Provinces was not considered, therefore, limiting the emergency assistance to the NYCA from the immediate neighboring control areas. This consideration is another measure of conservatism added to the analyses.

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 5-1 is as follows:

Table A-11
Outside World Reserve Margin Modeling

Area	Reserve Margin	LOLE
Hydro Quebec	30.5%*	0.264 Days per year
Ontario	14.0%	0.120 Days per year
PJM-MA	11.4%	0.697 Days per year
NEPOOL	8.7%	7.473 Days per year

*This is the summer ratio, the winter ratio is 2.7%

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Appendix B

Details of Study Results

B-1 - Introduction

Appendix B provides details of the GE-MARS case results referenced in the body of this report. This includes results of the inflection point case and various sensitivities cases, as well as an analysis of emergency operating procedures for the inflection point case required IRM. A history of the IRM values are given below in Table B-1.

B-2 - Historical IRMs

Table B-1
NYCA Historical IRM and LCR Information

Capability Year	Base Case IRM Developed by NYRC-ICS For NYCA	NYCA IRM Final Approved by NYSRC-EC	*LCR for NYC Final Approved by NYISO-OC**	*LCR for LI Final Approved by NYISO-OC**
2000	15.5%	**18.0%**	*80%*	*107%*
2001	17.1%	**18.0%**	*80%*	*98%*
2002	18.0%	**18.0%**	*80%*	*93%*
2003	17.5%	**18.0%**	*80%*	*95%*
2004	17.1%	**18.0%**	*80%*	*99%*
2005	17.6%	**18.0%**	*80%*	*99%*
2006	18.0%	**18.0%**	*80%*	*99%*
2007	16.0%	**16.5%**	*80%*	*99%*
2008	15.0%	**15.0%**	*TBD*	*TBD*

* The NYISO Operating Committee

B-3 - Base Case and Sensitivity Case Results

Table B-2 summarizes the 2008 capability year IRM requirements under inflection point case assumptions, as well as under a range of assumption changes from this 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 inflection point 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 base case results of 15% NYCA, 79% NYC, and 94% LI reserve margins. Capacity is then added or removed from all zones in NYCA until the NYCA LOLE approaches criteria. Note also that the transfer limits assumed in all sensitivity cases did not change from base case limits.

Table B-2
Description & Explanation of 2008 Sensitivity Cases

Case No.	Description & Explanation	%IRM	Zone J* (NYC) %	Zone K* (LI) %
	Transmission Sensitivities			
T1	**No Internal NYCA Transmission Constraints ("Free-Flowing" System)**	12.6%	N.A.	N.A.
	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. See the "Base Case – NYCA Transmission Constraints" section of the report.			
T2	**Remove Neptune Cable**	17.6%	80.8%	96.1%
	This case shows the impact on NYCA reliability if the new Neptune cable project is not available.			
T3	**Reduce transmission limits of the following upstate ties: Dysinger East, West Central, Volney East Moses South and Central East by 10% in the positive direction.**	15.1%	79.1%	94.1%
	This case addresses what a reduction in upstate transmission capability would provide.			
	Assistance From Outside World Sensitivities			
A1	**NYCA Isolated (No Emergency Assistance or Non-UDR Capacity from Outside World Areas)**	19.0%	81.9%	97.2%
	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). See the "Base Case Results – Interconnection Support during Emergencies" section of the report.			

* Locational Reserve Margin levels computed based on resulting capacity/load ratio.

A2	**Each external Control Area's IRM is at the level required to meet its LOLE criterion.**	**9.8%**	**75.2%**	**89.8%**
	Examine the NYCA IRM under the conditions where external Control Area is at its LOLE criterion of 0.100 days/year.			
A3	**Enhanced NEPOOL system (Assumes latest ISO-NE Regional Plan)**	**14.8%**	**78.9%**	**93.8%**
	Determine the impact of the latest New England Regional Transmission Expansion Plan.			
	Generation Unit Availability Sensitivities			
G1	**Increase EFORds from Base Case (represented by assuming the maximum annual EFORds during the 2002-06 period**	**16.2%**	**78.9%**	**95.0%**
	This shows the impact of the NYCA units having higher EFORs than the base case.			
G2	**Decrease EFORds from Base Case (represented by assuming the minimal annual EFORds during the 2002-2006 period**	**12.0%**	**76.9%**	**91.6%**
	This shows the impact of the NYCA units having lower EFORs than the base case.			
G3	**Prolonged outage of Indian Point 2 (one of five years on full outage)**	**16.6%**	**80.1%**	**95.3%**
	This shows the impact of an extended outage of IP 2 either by regulations or operational problems.			
	Load Sensitivities			
L1	**No Load Forecast Uncertainty**	**7.7%**	**73.8%**	**88.1%**
	This scenario represents "perfect vision" for 2008 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 and, to a smaller degree, economic uncertainties on IRM requirements.			
L2	**Assume the actual 2008 peak load will be the 0.9 percentile load represented in the Base Case load forecast uncertainty distribution model**	**9.2%**	**74.8%**	**89.3%**
	Assumes that the actual load exceeds 2008 forecast and LFU is not represented.			
L3	**Assume the actual 2008 peak load will be the 0.1 percentile load represented in the Base Case load forecast uncertainty distribution model**	**4.1%**	**71.2%**	**85.2%**
	Assumes that the actual load is lower than the 2008 forecast and LFU is not represented.			

Emergency Operating Procedure Sensitivity				
EP1	**No SCRs or EDRPs**	**15.2%**	**78.0%**	**94.4%**
	Verifies the impact of SCR and EDRP participation in the market.			
Environmental Initiative Sensitivities				
EN1	**HEDD Scenario**	**24.6%**	**85.8%**	**102.2%**
	This case assumes that the environmental restrictions appearing the 2008 RNA report for the year 2009 are modeled in this study for the year 2008. 2370 MW is removed. If no new capacity is added, the LOLE would be 1.288 days/year.			
EN2	**RGGI Scenario**	**17.1%**	**74.9%**	**98.0%**
	This case assumes that the environmental restrictions appearing the 2008 RNA report for the year 2010 are modeled in this study for the year 2008. 2139 MW of capacity is removed, which includes 1615 MW scheduled to be retired. If no new capacity is added the LOLE would be 0.435 days/year.			
Miscellaneous LOLE Sensitivities				
M1	**IRM vs. LOLE curve**	**See Figure B-1 below.**		
M2	**Monte Carlo 99.7% confidence level, including use of a 0.05 standard error.**	**14.3% low**	**15.8% high**	
	This shows the bandwidth or confidence interval of the expected LOLE value.			
M3	**LOLE for Monte Carlo convergence at a standard error of 0.025**	**14.6% low**	**15.4% high**	
	This shows the bandwidth or confidence interval of the expected LOLE value based on a standard error of 0.025.			
M4	**Combine Sensitivities A-2 and G-1**	**10.9%**	**76.1%**	**90.7%**

Figure B-1

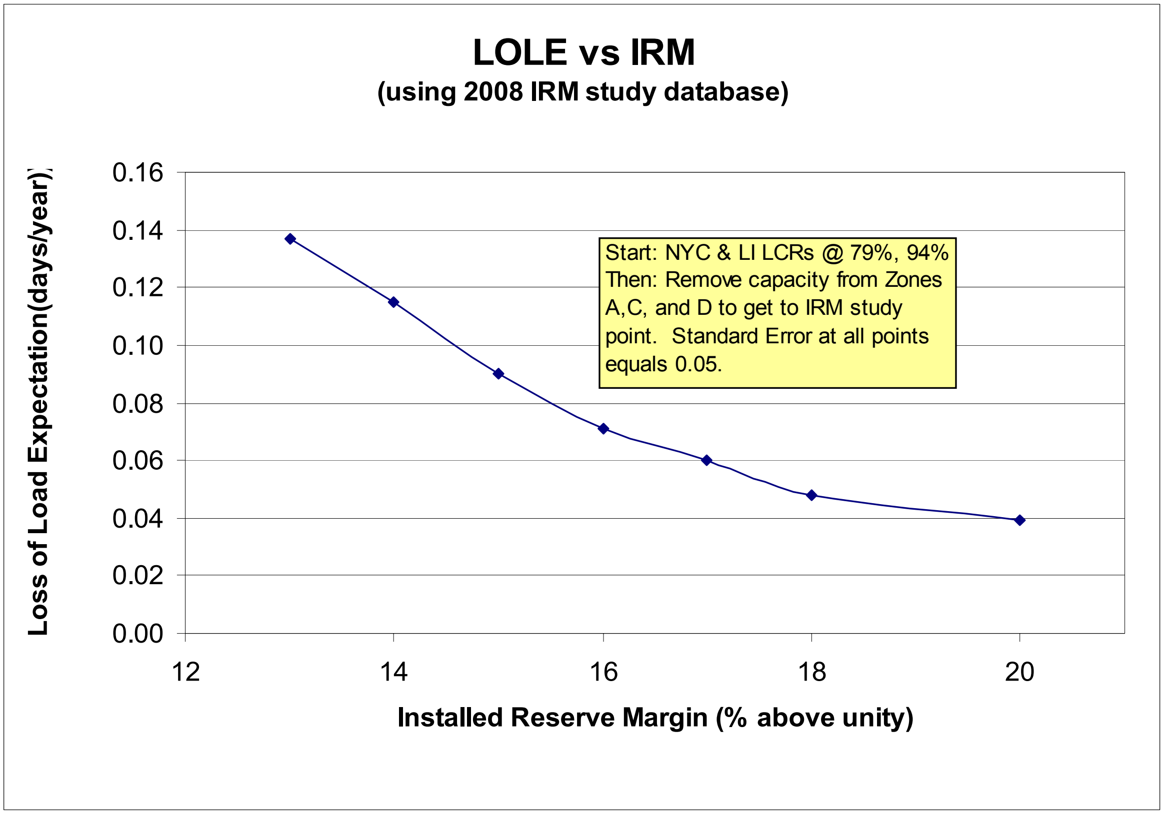

Figure B-1 shows the range of LOLE values as the Installed Reserve Margin changes. This is accomplished by holding the locational capacity reserve margins constant at 79% for NYC and 94% for Long Island.

B-4 - Frequency of Implementing Emergency Operating Procedures

In all cases, it was assumed that the EOPs are implemented as required to meet the 0.1days/year criterion. In the base case, the study shows that approximately 1.5 remote 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-3.

Table B-3
Implementation of Emergency Operating Procedures*
Base Case Assumptions (IRM = 15.0 %)

Emergency Operating Procedure	Expected Implementation (Days/Year)
Require SCRs	5.9
Require EDRPs	5.0
5% manual voltage reduction	4.7
30 minute reserve to zero	2.4
5% remote control voltage reduction	1.5
Voluntary load curtailment	1.2
Public appeals	1.1
Emergency purchases	1.1
10 minute reserve to zero	1.0
Customer disconnections	0.1

* See Appendix A, Table A-8