NEW YORK CONTROL AREA
INSTALLED CAPACITY REQUIREMENTS
FOR THE PERIOD
MAY 2007 THROUGH APRIL 2008

Technical Study Report

New York State Reliability Council, L.L.C.
Installed Capacity Subcommittee

January 5, 2007

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INTRODUCTION

Section 3.03 of the New York State Reliability Council (NYSRC) Agreement states that the NYSRC shall establish the annual statewide Installed Capacity Requirement (ICR) for the New York Control Area (NYCA) consistent with North American Electric Reliability Council (NERC) and Northeast Power Coordinating Council (NPCC) standards. This report describes a technical study conducted by the NYSRC Installed Capacity Subcommittee (ICS) for establishing the NYCA ICR, described as the required installed reserve margin (IRM), for the period of May 1, 2007 through April 30, 2008 (2007 capability year) in compliance with the NYSRC Agreement. The NYSRC Executive Committee will consider these study results, along with other factors, to establish the final NYCA IRM requirement for 2007-08.

The ICR relates to the IRM through the following equation:

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

The New York Independent System Operator (NYISO) will implement the statewide 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, in accordance with a 2001 NYISO filing to FERC. Also, in June 2003 the NYISO replaced its monthly Deficiency Auction with a Spot Market Auction based on FERC approved Demand Curves. These Unforced Capacity and Demand Curve concepts are described later in the report.

This 2007 IRM Study continues to implement two study methodologies that were utilized for the first time in 2005 for the 2006 IRM Study, the *Unified* and the *IRM Anchoring Methodologies.* These methodologies are discussed later in this report under Study Procedure. In addition to calculating NYCA IRM requirement, these methodologies identify corresponding Minimum Locational Capacity Requirements (MLCRs). In its role of setting the appropriate Locational Capacity Requirements (LCRs), the NYISO considers the MLCR determined in this study.

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*, http://www.nysrc.org/documents.html.

EXECUTIVE SUMMARY

The base case for 2007 IRM Study calculated that **NYCA IRM requirement for the period May 1, 2007 through April 30, 2008 to be 16.0%**. For the base case, the study also determined MLCRs of 80% and 99% for New York City and Long Island, respectively. 1, 2

1 There is a 99.7% probability that the base case result is within a range of 15.2% to 16.9%. See Appendix A.
2 These requirements result in a LOLE of 0.091. This is less than 0.1 because the locational values were rounded up to 80% and 99%.

The above 2007 base case study result is 2.0 percentage points less than the IRM requirement determined by the 2006 IRM Study. The principle reasons for this fairly large IRM reduction are: (1) the new version of the GE-MARS program used for this study included several changes, the most significant of which corrected the treatment of emergency operating procedures, (2) an updated transmission representation, including updated system operating limits and transmission cable outage rates; and (3) updated generating unit outage rates. (see Table 2).

For the first time the NYISO's an updated peak load forecast for the following summer period, based on the most recent actual summer load conditions, was used for this study. Use of this forecast allows both the IRM and NYISO LCR studies to use the same model.

The study also evaluated IRM requirement impacts caused by the updating of key study assumptions and various sensitivity cases. These results are depicted in Tables 1 and 2 and in Appendix B-1. The base case and sensitivity case results, along with other relevant factors, will be considered by the NYSRC Executive Committee for the determination of the final NYCA IRM requirement for the 2007 Capability Year.

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. The NYS Transmission System transfer capability in the above Reliability Rule is represented using emergency transfer limits.

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 NYSRC Reliability Rules can be found on the NYSRC Web site, www.nysrc.org.

IRM STUDY PROCEDURES

The study procedures used for the 2007 IRM study are described in detail in NYSRC Policy 5, *Procedure for Establishing New York Control Area Installed Capacity Requirements*, which was refined in 2006. Policy 5 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 can be found on the NYSRC Web site, www.nysrc.org.

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 capacity shortages.

GE-MARS is the primary analytical tool used for this probabilistic analysis. This program includes detailed load, generation, and transmission representation for the eleven NYCA Zones — plus four external Control Areas (Outside World Areas) directly interconnected to the NYCA. GE-MARS calculates "Loss of Load Expectation" (LOLE), expressed in days per year, to provide a consistent measure of system reliability.

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 LCRs. 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 New York City (NYC) and one for Long Island (LI).

Base case NYCA IRM requirements and related MLCRs are established by a supplemental procedure (termed the *IRM Anchoring Methodology*) which is used to define *anchor points* on these curves. From the results of GE-MARS simulations for a range of IRM values, the curves for this year's IRM study were derived by calculating the first derivative of the best fit second order polynomial function. (A second order polynomial was selected since it only produced a single solution at the Tangent 45 degree inflection point). These anchor points are selected by applying a tangent of 45 degrees ("Tan 45") analysis at the bend (or "knee") of each curve. NYSRC Policy 5 provides detailed descriptions of these two methodologies.

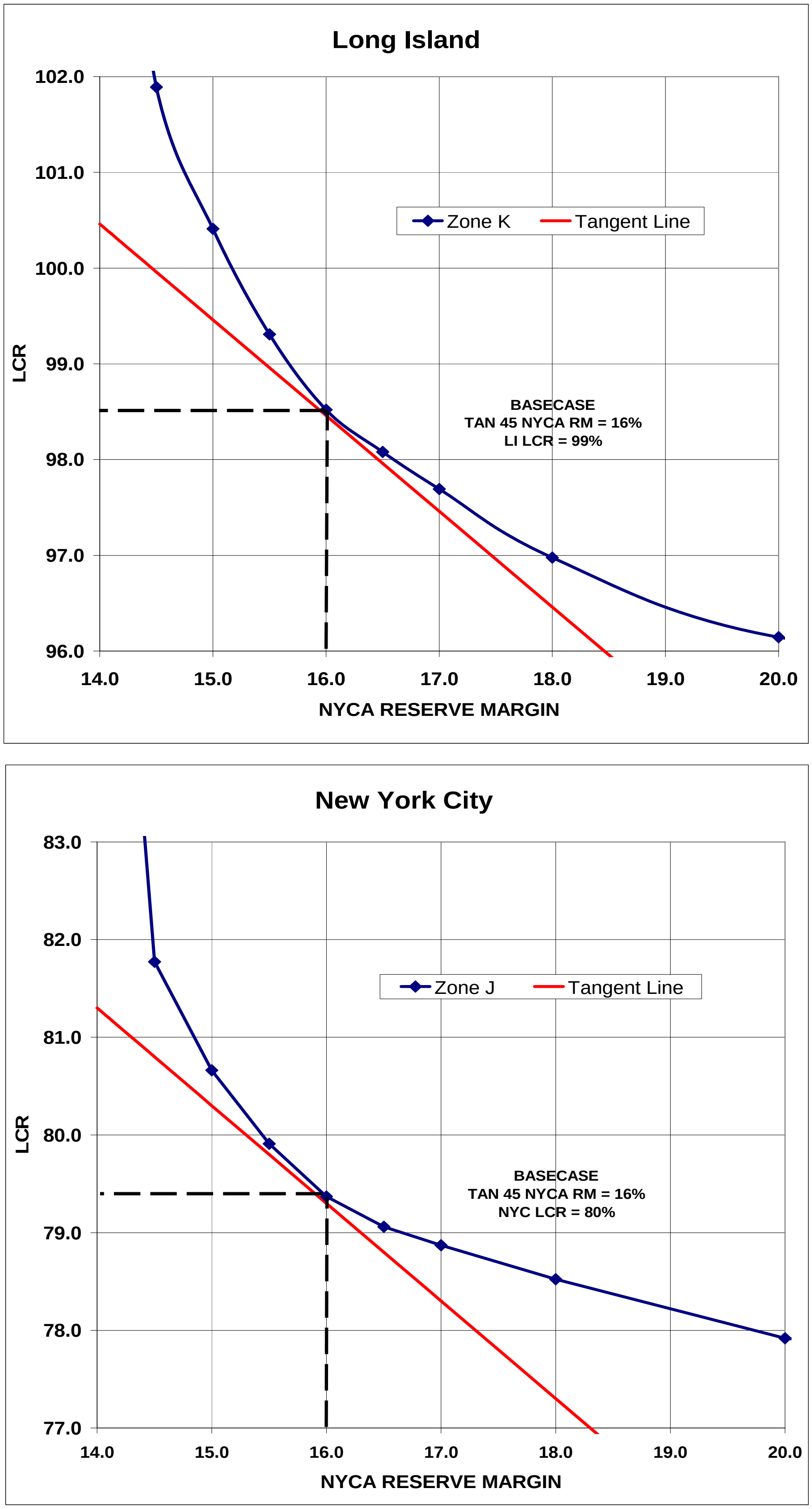
BASE CASE STUDY RESULTS

Year 2007 IRM base case study results show a required NYCA IRM of 16.0%. Accordingly, we conclude that maintaining the NYCA installed reserve of 16.0% over the forecasted NYCA 2007 summer peak season will achieve applicable NYSRC and NPCC reliability criteria for base case study assumptions shown in Appendix A. The base case study results show corresponding MLCRs for NYC and LI of 80% and 99%, respectively.

Figure 1 depicts the relationship between NYCA IRM Requirements and resource capacity in NYC and LI. The anchor points on these curves, from which these study results are

Figure 1

**NYCA Locational ICAP Requirements vs.
Statewide ICAP Requirements**



based, were evaluated using the "Tan 45" analysis described under "Study Procedures". Accordingly, we conclude that maintaining the NYCA installed reserve of 16.0% for the 2007 Capability Year, together with MLCRs of 80% and 99% for NYC and LI, respectively, will achieve applicable NYSRC and NPCC reliability criteria for the base case study assumptions shown in Appendix A.

Major parameter and modeling enhancements that influenced the 2007 NYCA IRM study results include:

- ***Interconnection Support during Emergencies.*** NYCA reliability can be improved by receiving emergency assistance support from neighboring interconnected control areas — in accordance with control area agreements during emergency conditions. Assuming such arrangements in the base case reduces the NYCA IRM by approximately 3.8 percentage points (see Table 1). A model for representing the neighboring control areas, similar to that applied in the 2006 IRM Study, was utilized for this study. In this model two of the Outside World Areas, ISO-NE 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 LIPA's new Neptune intertie, were modeled as a function of the availability of Northern New Jersey generation including Linden, Hudson, and Bergen.

- ***Peak Load Forecast.*** For the first time the NYISO's peak load forecast for the next summer period, i.e., 2007 -- based on the most recent actual summer load conditions -- was used for this study. Previous studies used preliminary forecasts prepared prior to the most recent summer. Use of the updated peak load forecast allows both the NYSRC IRM and NYISO LCR studies to use the same forecast.

- ***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 forced and partial outages that occur over the most recent five-year time period. The time span considered for the 2007 IRM study covered the 2001–2005 period. Average capacity availability improved for this period from that of 2000–2004, the period considered for the 2006 IRM study. This increase was mainly due to removing year 2000 data, which included prolonged outages of an Indian Point and a Lovett unit in the Lower Hudson Valley, from the average. Incorporation of this improvement in generating unit availability in the 2007 study model had a direct impact of reducing IRM requirements from 2006 IRM study results. Gas turbine and combined

- ***Resource Capacity Availability (Cont'd.)***

cycle capacity deratings are modeled using ambient temperature correction curves. The 2007 Study was the first study that incorporated temperature correction curves for combined cycle units.

The 2005 and 2006 IRM studies incorporated statewide dependable maximum net capacity (DMNC) reductions to offset overstatements of the capacity availability of certain resources reported to the NYISO. These studies incorporated DMNC reduction adjustments of 711 MW and 125 MW, respectively. The NYISO took steps to mitigate these capacity availability overstatements by improving generating unit availability reporting requirements. These initiatives included the modification of outage data collection software, requirements for the reporting of generation unavailability caused by transmission outages, education efforts, and expanding the number of NYISO audits. Because of the success of this program the NYISO reported to the NYSRC that capacity availability overstatements virtually no longer exist, and that therefore a DMNC adjustment was not needed for the 2007 IRM study.

Incorporation of generating unit outage rates from the most recent five-year time period, combined with the reduction of the DMNC adjustment to zero, has resulted in an IRM requirement decrease of approximately 0.4 percentage points from last year's study (see Table 2).

- ***NYCA Transmission Constraints.*** GE-MARS is capable of determining the impact of transmission constraints on the NYCA LOLE. This study, as with previous GE-MARS studies, consistently 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 March 28, 2006) determined that for 2007 the MLCRs for NYC and LI were 80% and 99%, respectively.

As previously discussed, Figure 1 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 "anchor point" of the curve where the IRM requirement rises much faster than the locational installed capacity levels are reduced. For base case assumptions, the anchor point in Figure 1 results in the base case IRM requirement of 16.0% and MLCRs for NYC and LI MLCR of 80% and 99%, 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 13.9%, 2.1 percentage points less than the base case IRM requirement (See Table 1).

- **Downstate NY Capacity Levels** - If the NYC and LI LCR levels were *increased* from the base case results to 88% and 106%, respectively, the IRM requirement would be reduced by 1.9 percentage points, to 14.1%. Similarly, if the NYC and LI locational installed capacity levels were *decreased* to 78% and 96%, respectively, the IRM Requirement would increase by about 4 percentage points, to 20%. (See Figure 1.)

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

Other important factors that impact IRM studies include:

- ***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 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 I, Zone J (NYC), Zone K (LI), and Zones A-H (the rest of New York State).

- ***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 994 MW of SCR capacity 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.

- ***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. This study assumes 228 MW of EDRP capacity resources in July and August (and less in other months), 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.*** The NYISO will implement EOPs as required to minimize customer disconnections. If a 16.0% IRM is maintained, firm load disconnections due to inadequate resources will not occur more than once in every ten years on average — in accordance with NYSRC and NPCC criteria. (Refer to Appendix B, Table B-2, for the expected use during 2006 of SCRs, EDRP, voltage reductions, and other EOPs.)

USE OF A NEW VERSION OF THE GE-MARS PROGRAM

Several programming changes were made by General Electric in Version 2.83 of GE-MARS, the version used for this study, which were not included in Version 2.69, the version used for the 2006 IRM study. The most significant change involves correction of program logic that limits the number of days per month that an emergency operating procedure (EOP) could be invoked.

As MARS implements EOPs in each zone in response to capacity deficiencies, it counts the number of days each month that each EOP has been used. If an EOP hits its limit, the program skips over that EOP and moves on to the next one for that zone. Prior to the above program correction the pointers to the next EOP in the zones where the limit had been reached were not being correctly incremented. The result was that in those zones, the EOPs beyond the limited EOP would not be implemented, reducing the amount of emergency relief that the program would be modeling. The larger the MW value of the EOP steps that follow the limited EOP the greater the impact that this problem would have on the final LOLE.

For the 2006 IRM Base Case at 18% reserves with location requirements of 80% in Zone J and 99% in Zone K, correcting this problem reduced the NYCA LOLE from 0.099 days/year to 0.078 days/year. The fact that this change in NYCA LOLE was the result of this code change was confirmed by removing the limits on the EDRP EOP step and rerunning the Versions 2.69 and 2.83. With this change in the data, which would cause the program to bypass the logic in question, the two versions produced identical results of 0.075 days/year NYCA LOLE.

The New York Independent System Operator (NYISO), acting on behalf of the New York State Reliability Council (NYSRC), performed a similar validation set of MARS runs. The first run used version 2.69 of the MARS program and eliminated all EDRP values, including removal of the call limits. The second run eliminated the EDRP values as well as call limits, but used version 2.83 of the program instead. Both of these runs resulted in an LOLE of 0.087 days/year. Based on the above set of validation runs, the NYISO recommended use of version 2.83 of the MARS program for resource adequacy studies.

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 1 shows IRM requirement results and related NYC and LI locational capacities for several selected sensitivity cases. A complete summary of all sensitivity case results are shown in Appendix B, Table B-1. Table B-1 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 "anchor point" or to fix the MLCRs for each case, or to fix the MLCRs to make them consistent with the base case MLCR results.

Table 1
Selected Sensitivity Case Results
NYCA IRM Requirements and Related NYC & LI Locational Capacities

Case	Case Description	IRM (%)	% Change from Base Case	NYC LCR (%)	LI LCR (%)
0	Base Case	16.0	--	80	99
1	NYCA Isolated	19.8	+3.8	83	103
2	Use 2006 "Gold Book" NYCA Peak Load Forecast	15.5	-0.5	80	99
3	No Load Forecast Uncertainty	10.2	-5.8	76	95
4	No SCRs or EDRPs	15.9	-0.1	80	99
5	No Voltage Reductions	18.2	+2.2	82	101
6	No Internal NYS Transmission System Constraints	13.9	- 2.1	*	*
7	Decrease External Control Area IRMs	16.9	+0.9	81	100
8	Increase External Control Area IRMs	12.2	-3.8	78	96
9	Increase Base Case FORs (Use a 250 MW GADf Derate)	16.4	+0.4	81	100

* Locational capacities are not relevant for this case.

NYISO IMPLEMENTATION OF THE NYCA IRM REQUIREMENT

NYISO Translation of NYCA Capacity Requirements to Unforced Capacity:

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 LCR 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.

NYISO Implementation of a Spot Market Auction based on a Demand Curves:

> 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.

COMPARISON WITH 2006 IRM STUDY RESULTS

The results of the Year 2007 IRM study show that the base case IRM result has decreased 2.0 percentage points compared to the Year 2006 IRM Study. Table 2 below compares the estimated IRM impacts of changing certain several key study assumptions from the 2006 Study. The primary drivers that changed the IRM requirement from 2006 include the use of a new version of the GE-MARS program (Version 2.83) which corrected the treatment of EOPs, an updated transmission system representation and system operating limits, and updated generating unit EFORs.

Table 2
Parametric IRM Impact Comparison with 2006 Study*

Parameter	Estimated IRM Req. Change (%)	IRM Req. (%)
Previous 2006 Study – Base Case IRM Result		**18.0**
New Version of GE-MARS Program	- 1.2	
Updated NYS Transmission Representation & System Operating Limits	- 0.3	
Updated Generating Unit EFORs	- 0.4	
Updated SCR and EDRP Capacity & Other EOPs	- 0.2	
Other Assumption Changes	+ 0.1	
Net Change from 2006 Study		- 2.0
2007 Study Base Case IRM Result		**16.0**

*This table reconciles assumption changes between the 2006 and 2007 studies.

APPENDIX A

NYCA INSTALLED CAPACITY REQUIREMENT RELIABILITY CALCULATION MODELS AND ASSUMPTIONS

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.

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, the last page of Appendix A compares the assumptions used in the 2005 and 2006 IRM reports.

Table A-1
Details on Study Parameters page numbers to be updated

Internal NYCA Modeling:

Figure A-1 Box No.	Name of Parameter	Description	Source	Reference
1	GE-MARS	The General Electric Multi-Area Reliability Simulation Program		See page 14
2	11 Zones	Load areas	Fig. A-2 page 17	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 2006 Gold Book* NYISO	See page 23 See page 23 See page 30
4	Zone Load Models	Hourly loads	NYCA load shapes. NYISO peak forecasts.	See page 19 33,544 MW NYISO Oct. forecast
5	Load Uncertainty Model	Account for forecast uncertainty due to weather and economic conditions.	Historical Data	See page 22
6	Transmission Capacity Model	Emergency transfer limits of transmission interfaces between Zones.	NYISO transmission studies	See page 32

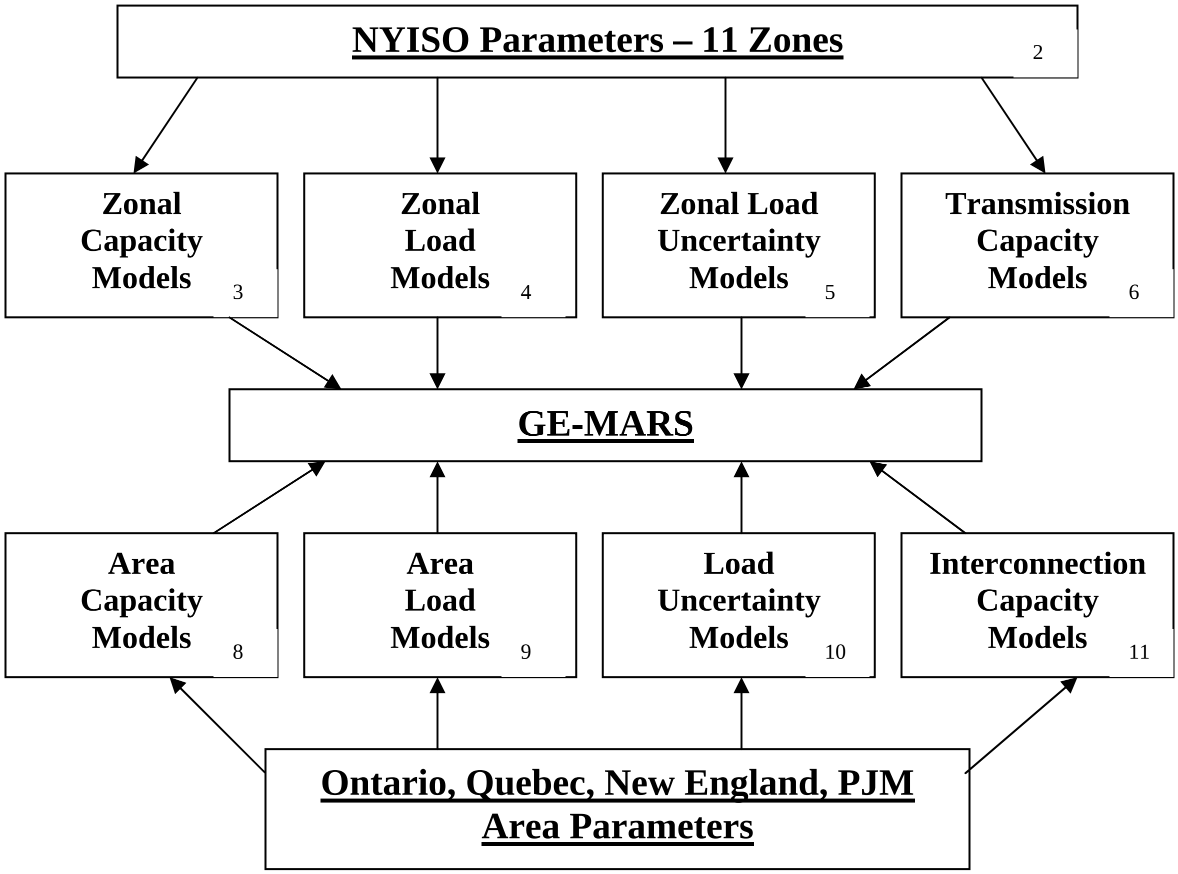
External Control Area Modeling:

Figure A-1 Box No.	Name of Parameter	Description	Source	Reference
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	See page 35
9	External Control Area Load Models	Hourly Loads	Same as above	See page 35
10	External Control Area Load Uncertainty Models	Account for forecast uncertainty due to weather and economic conditions	Supplied by External Control Areas	See page 36
11	Interconnection Capacity Models	Emergency transfer limits of transmission interfaces between control areas.	Supplied by External Control Areas	See page 34

* "2006 Load & Capacity Data" Report issued by the NYISO.

Figure A-1

NYCA ICAP Modeling



A-2 Computer Program Used for Reliability Calculation

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-5.3).

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

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

The table below 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

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

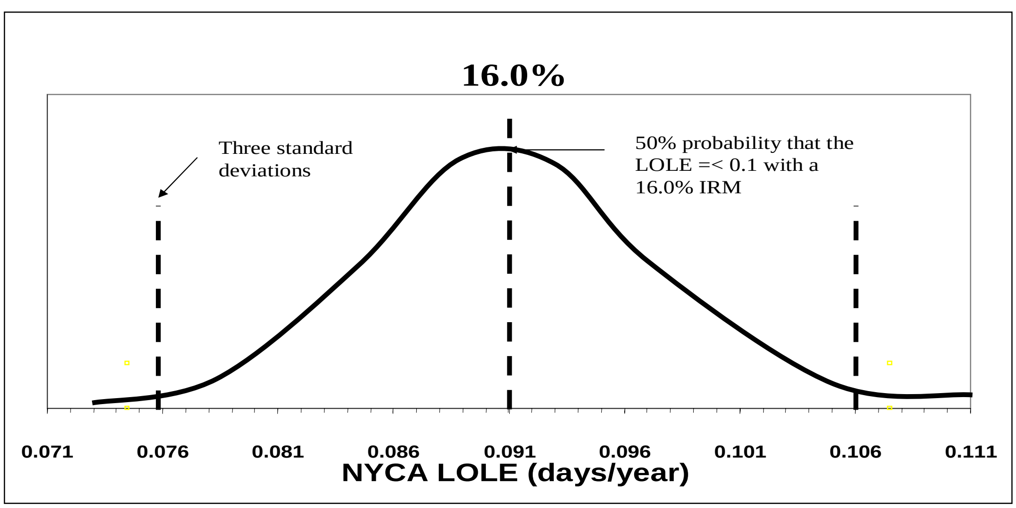
An important issue in using Monte Carlo simulation programs such as GE-MARS is the number of years of artificial history (or replications) that must be created to achieve an acceptable level of statistical convergence in the expected value of the reliability index of interest. The degree of statistical 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 based on the simulation data. 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 692 replications to converge to a daily LOLE for NYCA of 0.091 days/year with a standard error of 0.05 per unit, which corresponded to an IRM of 16.0 %. 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 0.076 days/year and 0.106 days/year were computed. The resulting IRM values of 16.9% and 15.2% define the 99.7% confidence interval. The statistical significance of the 16.0%, 16.9% and 15.2% numbers are a 0.15%, 50% and 99.85% probability of meeting the one in ten criterion, assuming perfect accuracy in all parameters.

Confidence Intervals



A-3 Representation of the NYCA Zones

Figure A-2 depicts the NYCA Zones represented in GE-MARS.

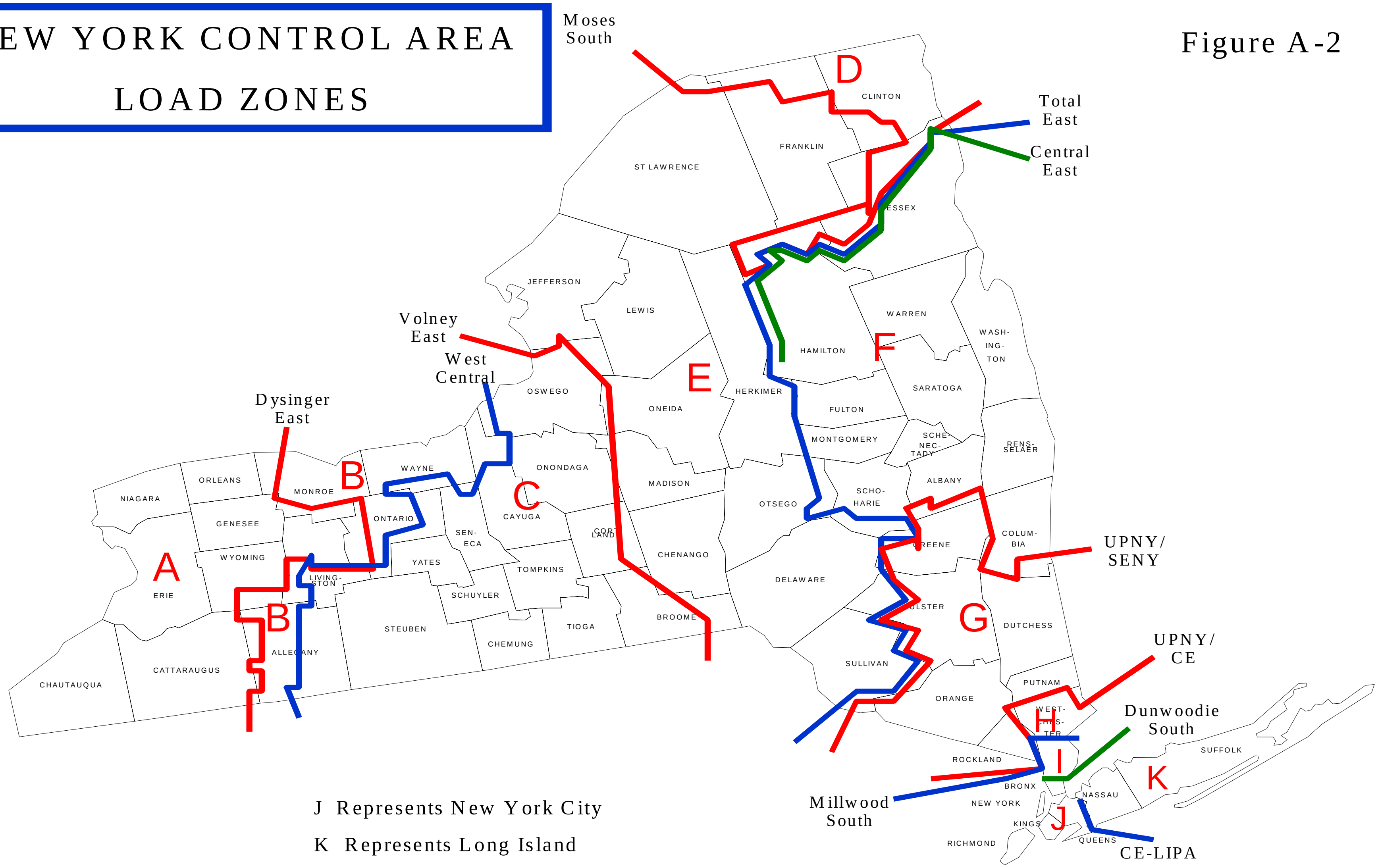
A-4 Conduct of the GE-MARS Analysis

An new version of the GE-MARS software (executable version 2.83) was tested to ensure that the new version produced acceptable results. The test compares results derived using the current GE-MARS version 2.83 with results based on a previous GE-MARS version 2.69 using the same assumptions.

The current base 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.

NEW YORK CONTROL AREA LOAD ZONES

Figure A-2



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 minimizing the amount of assistance that NYCA could receive from the other Areas.

A-4.1 Methodology

This year continued to use the Unified Methodology that was developed last year to simultaneously determine the NYCA installed reserve requirements and locational requirements. The details of this methodology can be found in The New York State Reliability Council Policy 5-1.

A-5 Input Data and Models

A-5.1 NYCA LOAD MODEL

Effect of Schedule Change on the 2007 IRM Forecast

In previous IRM studies, the load forecast used to develop 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. This year, the Executive Committee of the NYSRC requested a forecast for the 2007 IRM study to be prepared after the summer peak of 2006. This meant advancing the normal 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. In particular, the ICAP forecast is based in large part on data provided by the Transmission Owners (TOs). For the 2007 IRM forecast however, it was not possible to obtain all load data, complete the weather normalization process, and produce a forecast to meet this year's IRM schedule according to the procedures detailed in the manual. To meet the request of the NYSRC, the NYISO and TOs used as much data and results as possible from the TOs. To further aid this process, the NYISO also requested an expedited updated economic forecast from Moody's Economy.com. This economic forecast was proved in August 2006 versus the usual delivery date of September.

Using these abbreviated methods, the NYISO and the TOs jointly produced and reviewed a forecast in October 2006 for use in the 2007 IRM study. This forecast was based upon weather-normalized peaks load for each of the TOs, NYPA, and other NY municipalities for the hour of the NYISO coincident peak on August 2, 2006. The forecast for 2007 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 was used to adjust the RLGFs used in the prior ICAP forecast.

The final result was a 2007 peak load forecast based upon the most recent data available for the IRM study yet still maintain the schedule for the 2007 IRM study. It is worthwhile to compare the October 2006 IRM forecast to the 2006 Load and Capacity forecast and to the actual peak experience in 2006.

2006 Load & Capacity Report	Summer 2006	Summer 2007
NYCA System	33,295	33,831
Zone J NCP	11,630	11,800
Zone K NCP	5,348	5,549

At the time the 2006 Load and Capacity Report was issued, the 2007 peak forecast to be used in the IRM study was 33,831 MW. This forecast used data from the 2005 summer peak experience and the fall 2005 economic forecast from Economy.com.

Actual 2006 Peak Experience	Actual Peak	Weather Normalized Peak
NYCA System	33,939	33,100
Zone J NCP	11,343	11,585
Zone K NCP	5,667	5,200

The summer of 2006 was characterized by extremely hot temperatures and actual peaks surpassed the forecasts. However after weather-normalizing the peaks, they are seen to be lower than those expected from the Load and Capacity Report. The economy had slowed somewhat due in part to declines in the housing market. Consequently, the Economy.com forecast prepared in August 2006 reflected a slower growth in the future.

The 2007 load forecast prepared in October 2006 and the preliminary ICAP forecast for 2007 are shown next. The 2007 load forecast is 287 (33,831 – 33,544) MW lower than the forecast which would otherwise have been used. Subsequently, the NYISO and the TOs have refined their estimates of weather normalization, demand-side programs, and economic growth to arrive at a preliminary 2007 ICAP forecast of 33,370 MW.

Forecasts for Summer 2007	IRM Forecast - October 2006	Preliminary 2007 ICAP Forecast
NYCA System	33,544	33,370
Zone J NCP	11,775	11,780
Zone K NCP	5,478	5,422

Incorporating the experience of the summer 2006 was beneficial to the forecast provided for the 2007 IRM study because the economy had shifted since the previous forecast was prepared. Economic data is dynamic in both past and future directions. Historical economic time series are revised and as additional information becomes available, estimates of the future will change. Even if it is not possible to completely align the ICAP forecast and the IRM forecast for a given year, the IRM forecast will be improved by waiting until the most recent summer has passed.

Load Shape Analysis

The 2007 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 2005. The conclusion reached this year was the same as in 2005 and 2006 - 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 relatively constant. The table below presents load trends from 1995 to 2005. The chart shows the actual load shares in each year from 2002 to 2006. There is no discernible trend in this more recent time frame. 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.

Share of NYCA Peak Load Accounted for by Load In:

	J	K	A - I
1995	32.2%	13.4%	54.4%
1996	32.2%	13.4%	54.4%
1997	32.8%	13.9%	53.3%
1998	33.1%	14.4%	52.5%
1999	34.0%	15.3%	50.7%
2000	34.4%	15.3%	50.2%
2001	34.5%	15.4%	50.1%
2002	34.2%	15.7%	50.1%
2003	34.0%	15.8%	50.2%
2004	34.0%	16.0%	50.0%
2005	33.9%	16.1%	50.0%

(Average of current and preceding two years.)

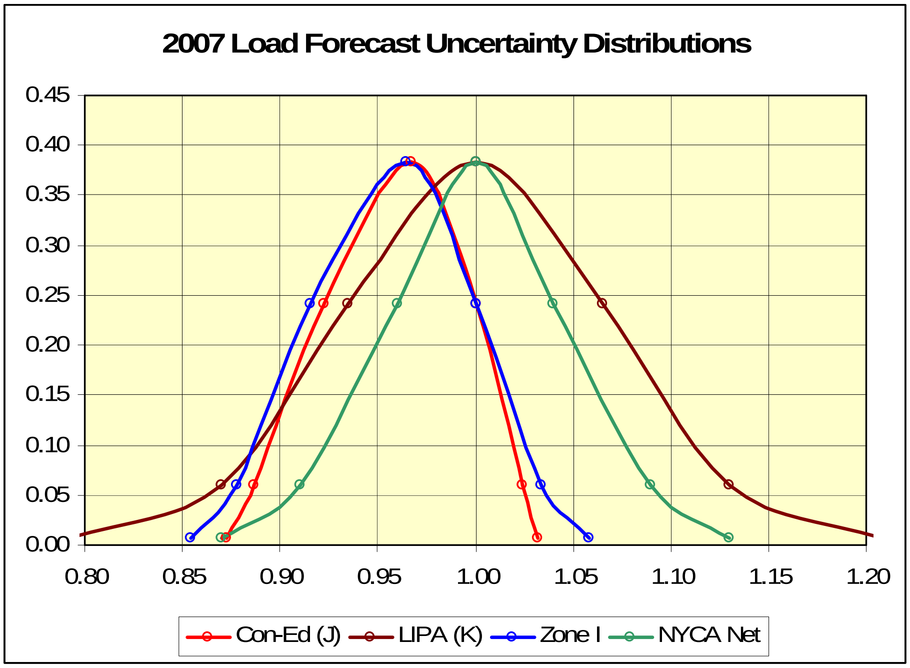
A-5.1.1 ZONAL LOAD FORECAST UNCERTAINITY

For 2007, new load forecast uncertainty models were provided by Consolidated Edison and LIPA for Zones J and K respectively. Additional models were developed for Zones A-H and for Zone I. The models are presented below.

2007 Load Forecast Uncertainty Models

Multiplier	Zone I	Con Ed (J)	LIPA (K)	NYCA Net
0.0062	1.0580	1.0320	1.2075	1.1300
0.0606	1.0335	1.0245	1.1297	1.0900
0.2417	1.0000	1.0000	1.0648	1.0400
0.3830	0.9645	0.9673	1.0000	1.0000
0.2417	0.9156	0.9222	0.9352	0.9600
0.0606	0.8782	0.8869	0.8703	0.9100
0.0062	0.8539	0.8730	0.7925	0.8700

Figure A-3



The Con Ed (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 2006. The approach developed in 2006 for the remaining zones is maintained in the IRM 2007 study. The models for Zones A to H were developed by simulating several historical high CTHI observations in the NYCA day-ahead zonal forecast models. The predicted peak loads were then used to estimate uncertainty distributions for these zones.

A-5.2 NYCA Capacity Model

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 "2006 Load and Capacity Data" (Gold Book):

- **<u>Retirements</u>:**

Huntley 65 & 66	165 MW	Zone A
Lovett 3	46.8 MW	Zone G
Lovett 5	176.2 MW	Zone G

- **<u>New Units: (Units installed during 2006)</u>**

SCS Astoria	500 MW	Zone J

- **<u>Planned Units for 2007</u>:** (These units had a signed interconnection agreement by August 1, 2006.)

Prattsburgh Wind Park	79 MW	Zone B
Maple Ridge Wind Power Phase 2	100 MW	Zone E

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

<u>Generating Units</u>

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. 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. The 2006 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. Performance data for all 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 2007 IRM Study. (See Figure A-4)

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 2001 through 2005. 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-7 provides a graph of scheduled outage trends over the 1992 through 2005 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 Flat Rock and Prattsburgh 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.

Figure A-4

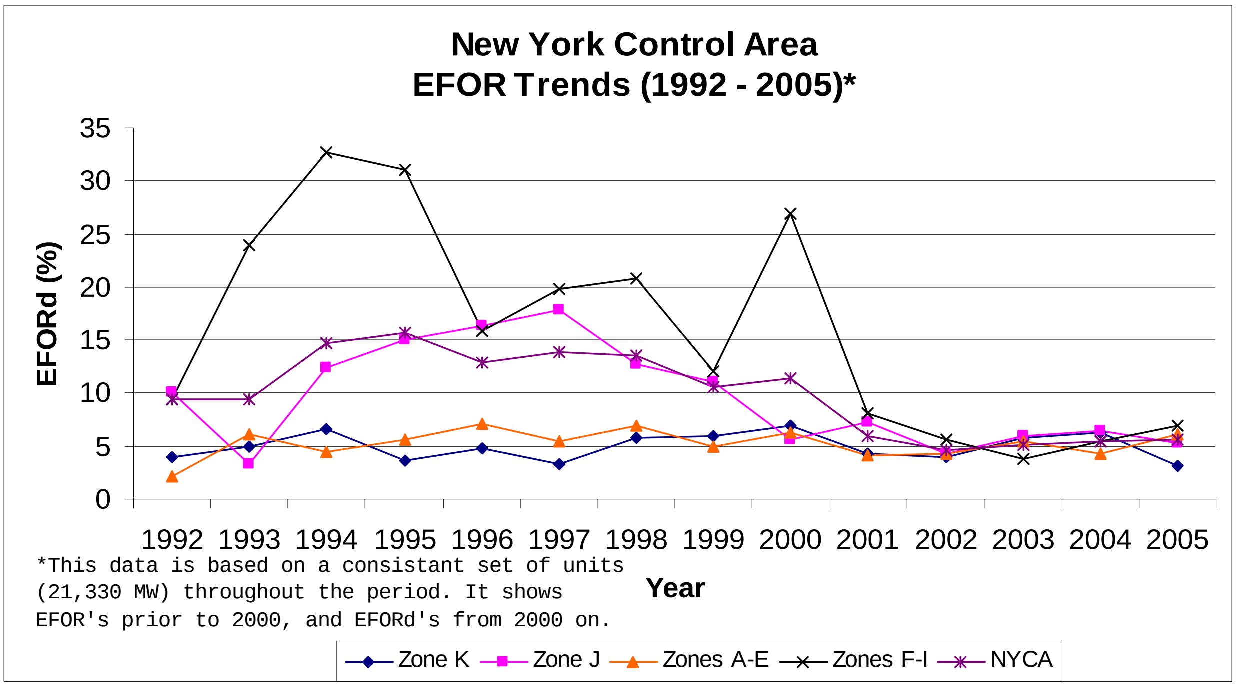


Figure A-5 provides a graph of Equivalent Forced Outage Rates under Demand (EFORd). The graph presents unit weighted averages for four areas within the NYCA along with a NYCA total aggregate

Equivalent Availability. The equivalent availability factor accounts for forced, partial, scheduled, and maintenance outages. Figure A-5, which is based on NERC-GADS data for New York units, shows that there is a continued trend of improved reliability.

Figure A-6 provides NERC-GADS data industry-wide. The continued improved availability is similar to that experienced in the NYCA.

Figure A-5

NYCA EQUIVALENT AVAILABILITY

BASED ON NERC-GADS DATA FROM 1982 – 2005

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

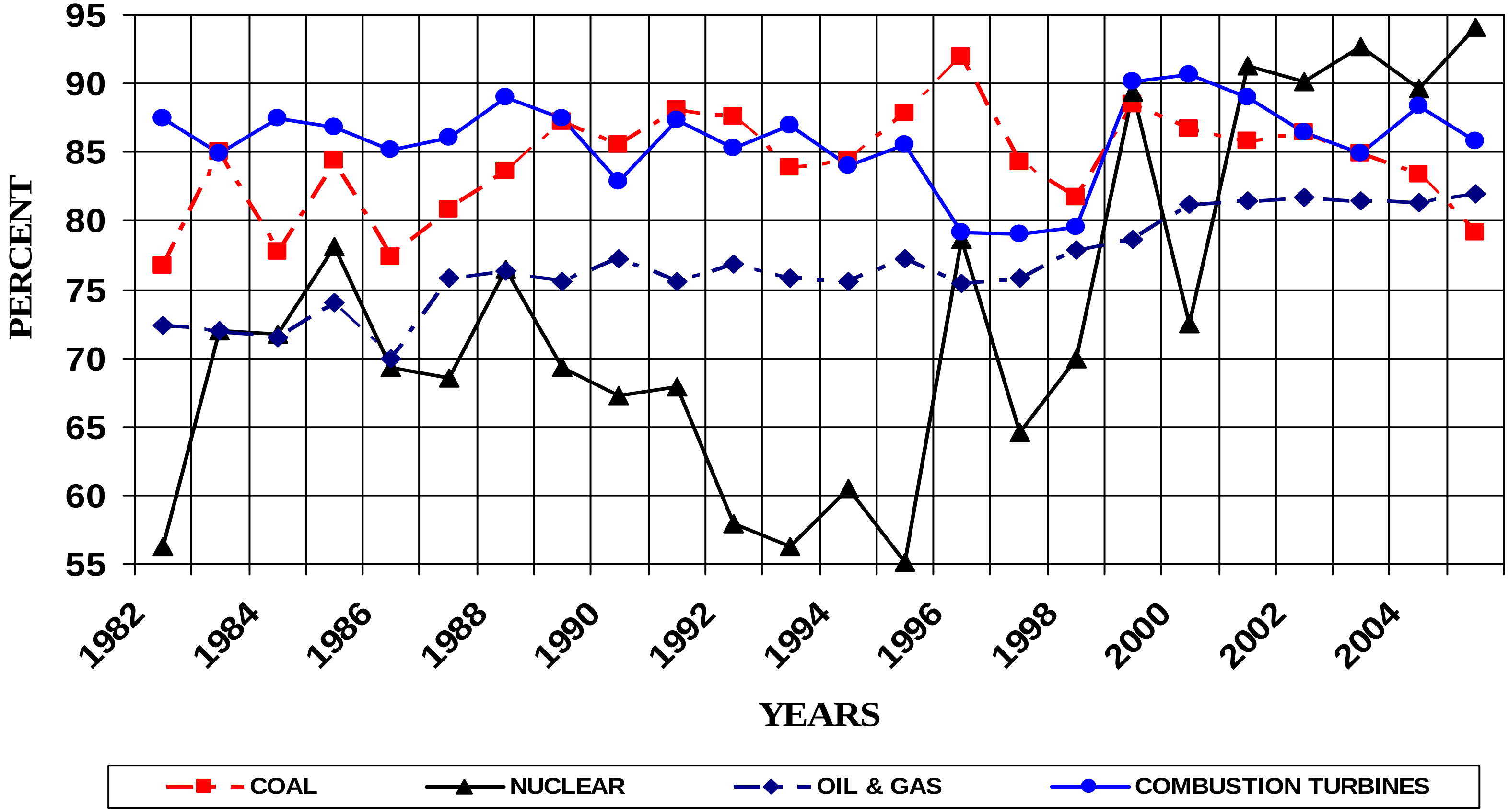


Figure A-6

NERC EQUIVALENT AVAILABILITY

BASED ON NERC-GADS DATA FROM 1982 - 2005

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

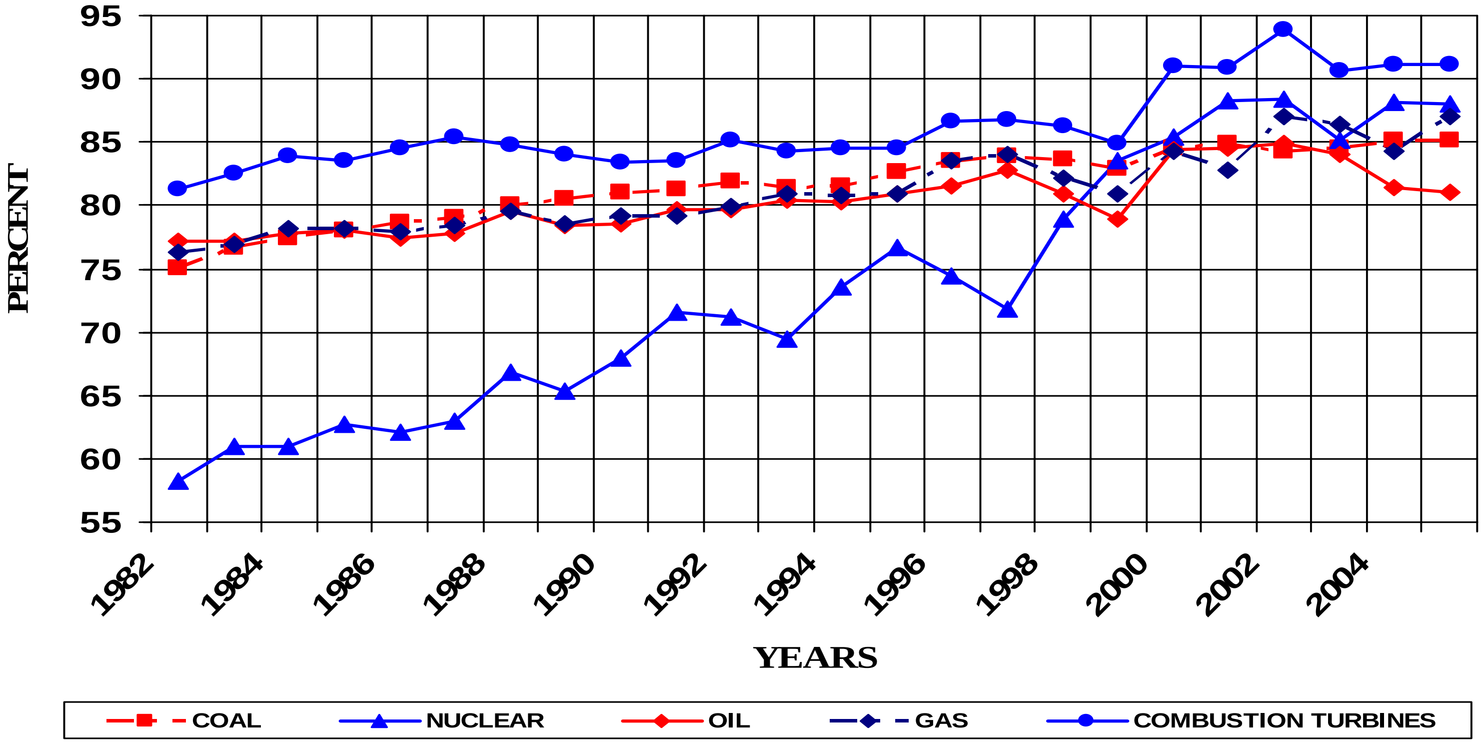


Figure A-7

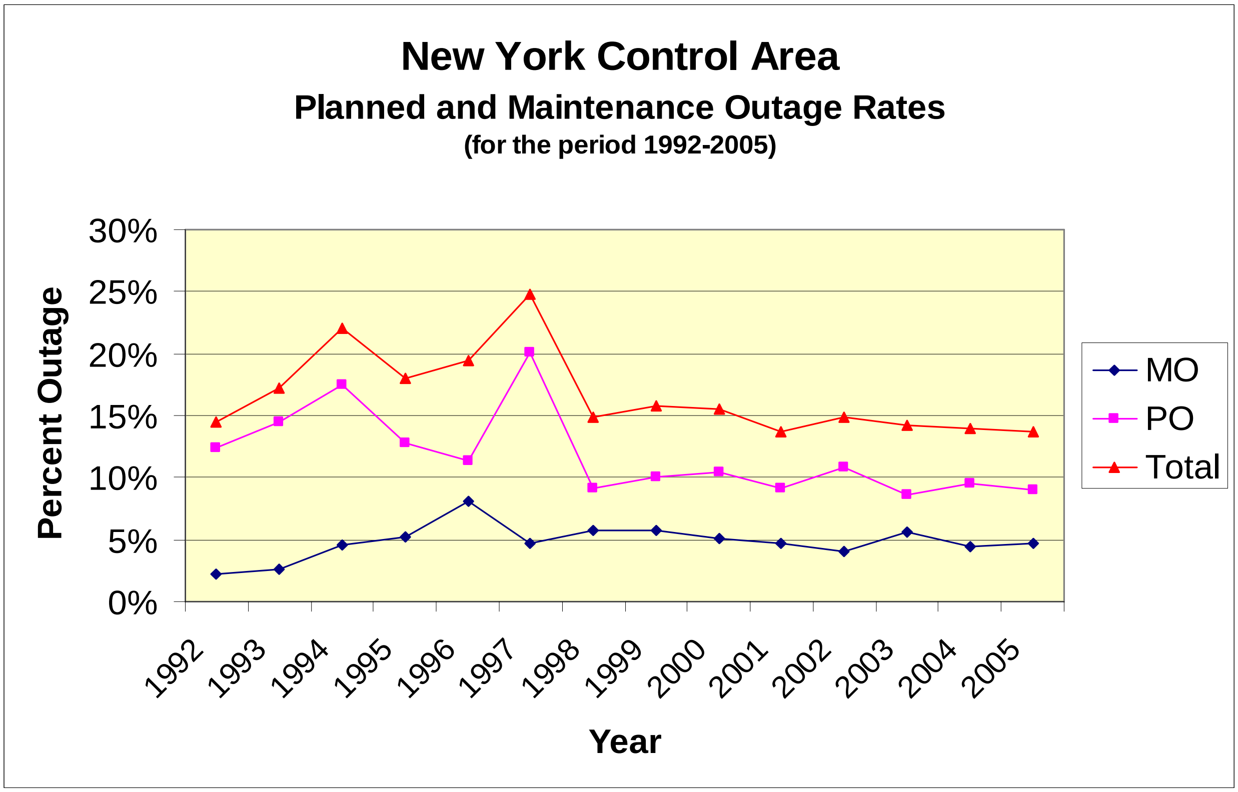
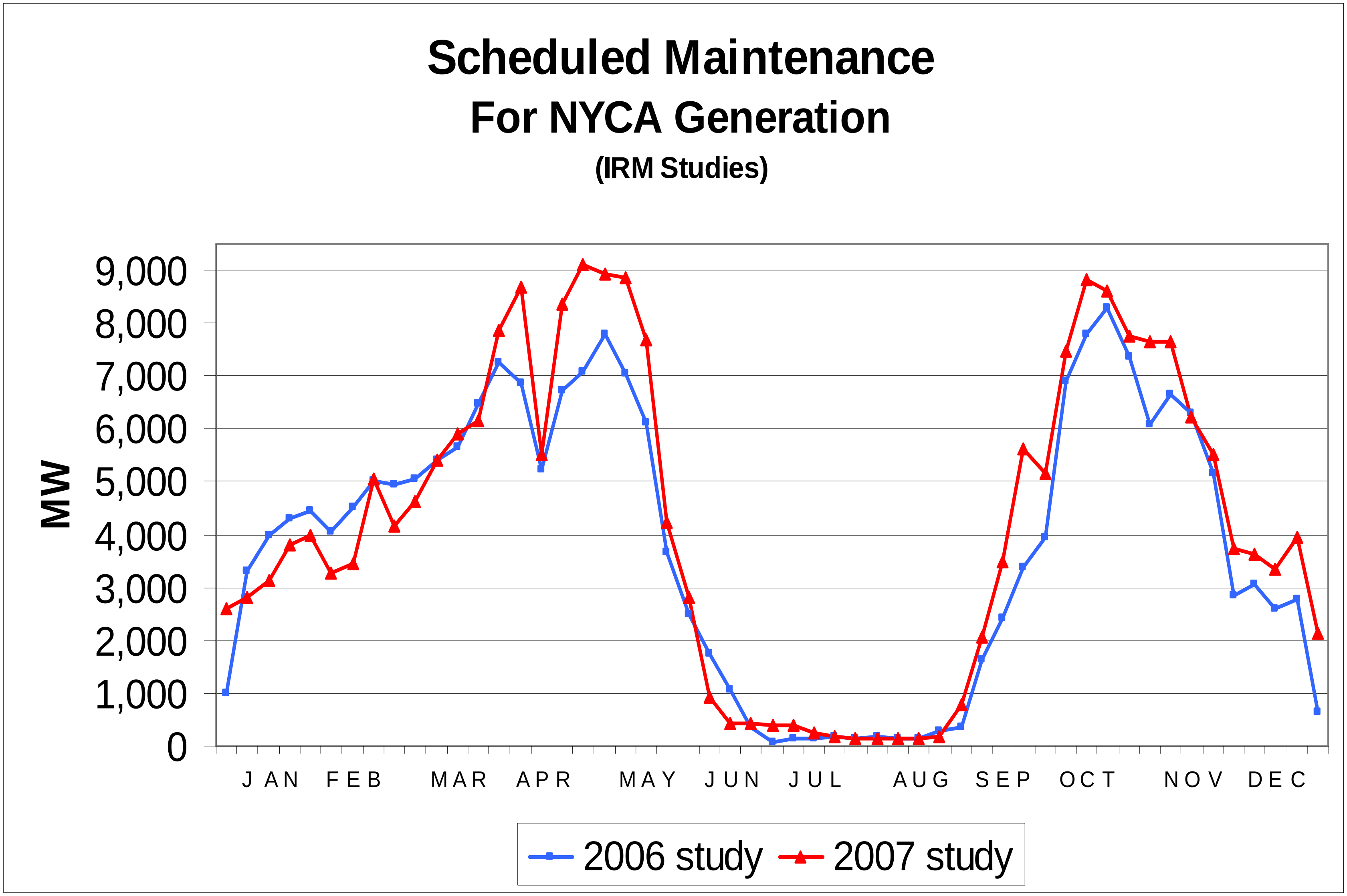


Figure A-8 shows the amount of capacity assumed to be scheduled out in the 2006 and 2007 studies.

The planned outages in the current study over the 2007 summer period are approximately 150 MW.

Figure A-8


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
2006 study
2007 study

Combustion Turbine Units. Observations of combustion turbine performance over the past several years have indicated that the output of these units is limited at temperatures above design conditions. This derate has been measured as a steady value each year (80 MW per degree above 92 degrees F), and is applied directly against those units that are impacted when the load levels exceed forecast.

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.

This year the temperature deratings have also been applied to the combined cycle units based on individual temperature correction curves provided by the Market Monitoring Unit of the NYISO. These curves provide 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 DNMC output at peak conditions (an average of temperatures obtained at the time of the transmission district previous four like capability period peaks), the temperature correction for the combined cycle units is derived for and applied to temperatures above transmission district peak temperatures.

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 1,080 MW EOP step, discounted to 994 MW in July and August (and further discounted in other months proportionally to the monthly peak load). Of the 994 MW of SCRs modeled, 135 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. EDRPs are modeled as a 228 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 507 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.

Transactions

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: 55 MW from Ontario, 1000 MW from HQ, 730 MW from New England and 1300 MW from PJM. This totals 3085 MW of expected summer external ICAP. For this analysis the New England to Long Island (Cross Sound Cable) firm transaction associated with LIPA UDR is modeled as a 330 MW ISO-NE ICAP generator with a historically determined forced outage rate connected to a tie between New England and Long Island. This tie has a 1.3% Forced Outage Rate. The expected amount of external ICAP for the winter ranges from 1750 MW to 2860 MW. NYISO studies have indicated that the maximum external ICAP that can be purchased without impacting reliability is 3085 MW (including the capacity from the Cross Sound Controllable Line).

All firm sales are modeled as listed in the 2006 Gold Book for the year 2007.

In calculating the IRM, all sales are subtracted from the Installed capacity. Purchases are not included. The Flat Rock and Prattsburgh capacity is added to the installed capacity number at their full rated output.

A-5.3 Emergency Operating Procedures (EOPS)

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

Table A-2

Emergency Operating Procedures

Step	Procedure	Effect	MW Value
1	Special Case Resources	Load relief	1,080 MW*
2	Emergency Demand Response Prog.	Load relief	228 MW
3	5% manual voltage Reduction	Load relief	171 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	465 MW**
6	Voluntary industrial curtailment	Load relief	156 MW**
7	General public appeals	Load relief	108 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 1,080 MW, however they are discounted to 994 MW in July and August and further discounted in other months.*
** *   These EOPs are modeled in the program as a percentage. The associated MW value is based on a forecast 2007 peak load of 33,544 MW. Includes 11 MW of curtailed company use.*

The above values are based on the year 2006 results associated with a 2007 peak load forecast of 33,544 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. The EOPs presented in Table A-2 were modeled in the GE-MARS program.

A-5.4 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-9.

The interface tie limits used in the 2006 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 2005 and 2006 Operating Study Reports, the 2004, 2005 and 2006 Area Transmission Reviews, the Reliability Needs Assessment (RNA) in the 2005 Comprehensive Reliability Planning Process, and the 2005 Hudson Valley Voltage Analysis Report were reviewed to update the transfer limits. Databases from the 2006 RNA were also used in the assessment. 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.

Changes in Topology and Interface Groupings

The most significant change in the topology was the implementation of a separate Zone AG to capture the more significant impact of the Athens and Gilboa plant on the UPNY/SENY Limit.
An updated UPNY/SENY group was created to capture the impact of these units. Comparatively, the shift factors for Athens generation are 40 % higher and for Gilboa units they are 20% higher. To reflect this difference in shift factors, half of the Gilboa plant and the full Athens plant were placed in the new Zone AG. A multiplier of 1.4 was assigned for the interface tie from Zone AG to Zone G to reflect the shift factor differences. A New England to New York Interface Grouping was also added. Its limit was taken from the 2006 Summer Operating Study.

Changes in Thermally Limited Interfaces

The interface limit for I to K was increased from 1270 Mw to 1290 Mw based on recent studies performed by LIPA. 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 the entire Consolidated Edison's 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. On the other hand, the Long Island interface showed a significant increase due to the availability increase of feeders Y49 and Y50 that tie Long Island with Area I.

The weighted average EFOR for all six cables improved from 2.47% to 2.22%. The weighted average for the three internal cables improved from 2.03% to 1.32%

Interconnection Support during Emergencies

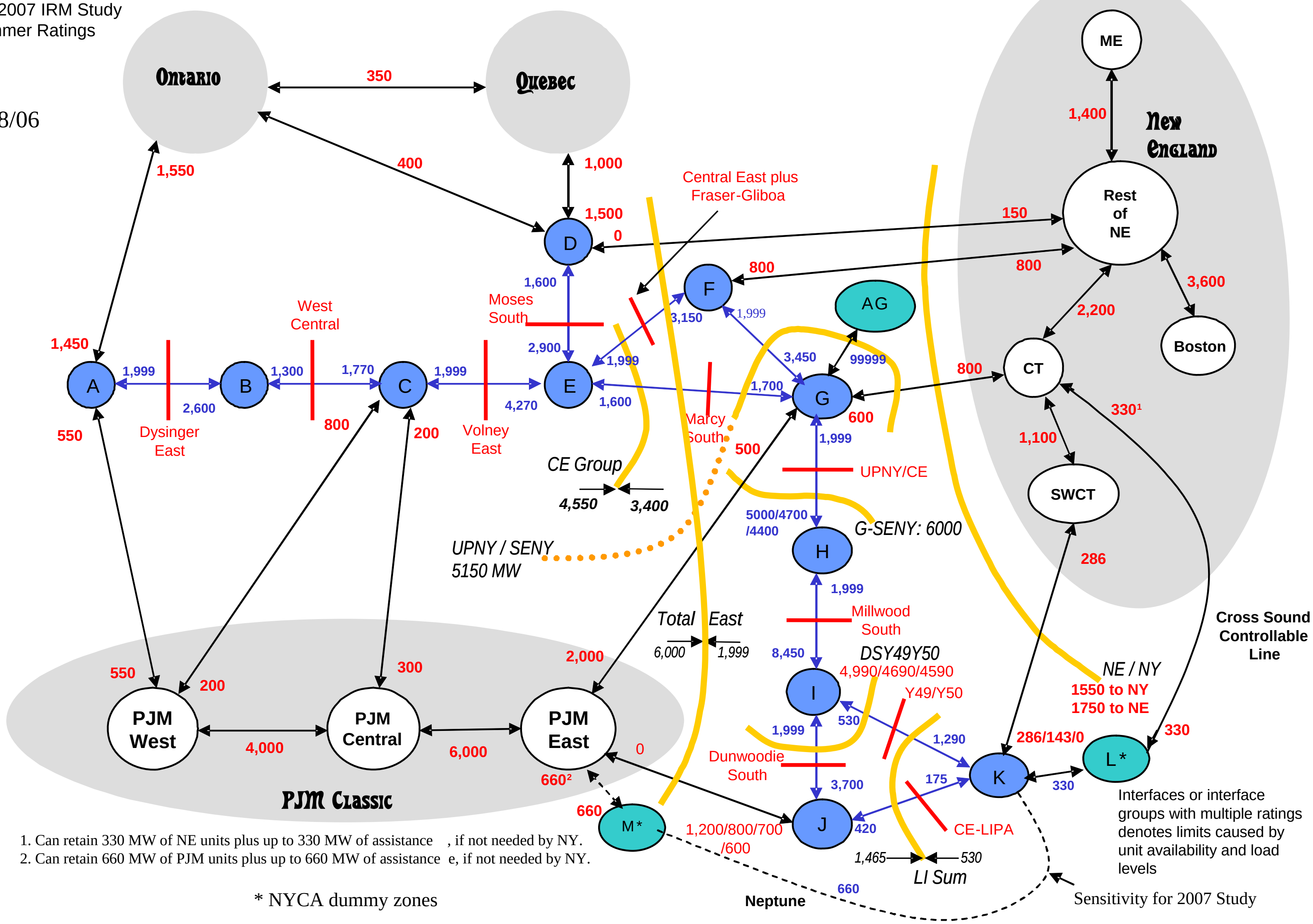
Base case assumptions considered the full capacity of transfer capability from external Control Areas (adjusted for grandfathered contracts and estimated external capacity purchases) in determining the level of external emergency assistance.

Figure A-9

New York Control Area

Transmission System Representation
For 2007 IRM Study
Summer Ratings

9/28/06



1. Can retain 330 MW of NE units plus up to 330 MW of assistance , if not needed by NY.
2. Can retain 660 MW of PJM units plus up to 660 MW of assistance e, if not needed by NY.

* NYCA dummy zones

A-5.5 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-5.6 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 overdependence 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 overdependence 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.

The Ontario and Quebec Area representations are based on the models provided for the NPCC study titled "Summer 2001 Multi-Area Probabilistic Reliability Assessment" dated May 2001 (CP-8).

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 New England and Ontario models (the only ones other than New York that explicitly modeled EOPs) to avoid the difficulty in modeling the sequence and coordination of implementing them. This is a conservative measure.

The assistance from East Central Area Reliability Council (ECAR) 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.

A-6 Assumption Summary - Comparison of Assumptions Used in the 2006 Study and 2007 Study

While some of the following assumptions have not been updated, they have all been reviewed to be sure that they are still current and appropriate.

Base Case Assumption	**2006 Study**	**2007 Study**
NYCA Capacity	All Capacity in the NYCA	All Capacity in the NYCA
NYCA Unit Ratings	Based on 2005 Gold Book	Based on 2006 Gold Book
Planned Capacity	Updated to time of study	Updated to time of study
Forced and partial outage rates	NERC-GADS 2000-2004 plus a 125 MW DMNC derating.	NERC-GADS 2001-2005.
Planned outages	Based on schedules received by NYISO as of Sept. 2004 & adjusted for history	Based on schedules received by NYISO as of Sept. 2005 & adjusted for history
Non NYPA hydro modeling	45% derating	45% derating
Unit Maintenance Schedule	Historic adjusted for forecasted time of year	Historic adjusted for forecasted time of year
Neighboring Control Areas – Ontario and Quebec	NPCC CP-8 2001 Study	NPCC CP-8 2001 Study
Neighboring Control Area – New England	New multi area model based on data from New England.	Continue to use multi area model.
Neighboring Control Area – PJM	New multi area model based on data from PJM.	Continue to use multi area model.
Load Model	Base Case NYCA 2002 shape	Base Case NYCA 2002 shape
Peak Load Forecast	Gold Book forecast of 32,400 MW	ISO October forecast of 33,544 MW
Load Forecast Uncertainty	Includes improved uncertainty model that models three Areas of NYCA separately	Continue to model three Areas of NYCA separately
External ICAP	3085 M Total, 55 from Ontario, 1000 from HQ, 730 from NE and 1300 from PJM	3085 MW Total, 55 from Ontario, 1000 from HQ, 730 from NE, and 1300 from PJM
Emergency Operating Procedures	1930 MW load relief (Includes 935 MW SCRs and 210 MW EDRPs)	2122 MW load relief (Includes 1080 MW SCRs and 228 MW EDRPs)
Locational ICAP Levels	Locational ICAP Levels are identified at various IRM levels from this study.	Locational ICAP Levels are identified at various IRM levels from this study.
Transfer Limits	2005 NYISO Assessment	2006 NYISO Assessment

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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 anchor point case and various sensitivities cases, as well as an analysis of emergency operating procedures for the anchor point case required IRM.

B-2 Base Case and Sensitivity Case Results

Table B-1 summarizes the 2007 capability year IRM requirements under anchor 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 anchor point case required IRM would change for assumption modifications, either one at a time, or in combination.

Table B-1
Description & Explanation of 2007 Sensitivity Cases

Case No.	Description & Explanation	% IRM	% LCRs	
			Zone J (NYC)	Zone K (LI)
1	**NYCA Isolated (No Emergency Assistance or Non-UDR Capacity from Outside World Areas)**	**19.8%**	**82.9%**	**102.3%**
	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.			
2	**Use 2006 "Gold Book" NYCA Peak Load Forecast**	**15.5%**	**79.6%**	**98.6%**
	This sensitivity examines the effect of using the NYISO forecast that was prepared prior to the 2006 summer period, using the NYISO's 2006 Load & Capacity Data (Gold Book) forecast, issued in March 2006. The Gold Book forecast had been used for all previous IRM studies. For this year, however, an updated forecast was specifically prepared for this study by the NYISO in October 2006 – and based on actual 2006 summer conditions. This forecast was used as the base case peak load forecast assumption. See the "Base Case Results – Peak Load Forecast" section of the report.			
3	**No Load Forecast Uncertainty**	**10.2%**	**75.7%**	**94.1%**
	This scenario represents "perfect vision" for 2007 peak loads, assuming that the forecast peak loads for NYCA and the Outside World areas 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.			

4	**No SCRs or EDRPs**	**15.9%**	**79.6%**	**98.9%**
	Special Case Resources (SCRs), like traditional central generation stations, can be used to satisfy the NYCA IRM requirement, while Emergency Demand Response Program (EDRP) suppliers represent voluntary resources which are available – in addition to those resources which satisfy the NYCA IRM. The intention of this sensitivity case is to demonstrate the impact of replacing traditional central generation facilities with SCRs and of removing EDRP suppliers. Eliminating SCRs from the study results in a lower IRM because the forced outage rates associated with SCRs are higher than the average system forced outage rates. Conversely, removing EDRPs causes an increase in IRM because the EDRP suppliers provide benefits from their status as voluntary resources. The base case IRM study models an effective value of EDRP based on the historic performance from a given set of registered suppliers. The net effect of the SCRs and EDRP suppliers tends to have an offsetting effect for this particular study year. See the "Base Case Results – SCR and EDRP" sections of the report.			
5	**No Voltage Reductions**	**18.2%**	**81.7%**	**100.9%**
	This sensitivity case determines the reliability impact of voltage reductions as an operational measure within the NYCA system.			
6	**No Internal NYCA Transmission Constraints ("Free-Flowing" System)**	**13.9%**	**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.			
7	**Decrease External Control Area IRMs**	**16.9%**	**80.7%**	**99.7%**
	This case simulates the impact on the NYCA IRM when the respective IRM levels from neighboring control areas are less than was assumed in the base case. When available external capacity available for reserve sharing is reduced, the IRM will increase. The lower external control area IRMs in this case are simulated by increasing base case peak loads by 10%.			
8	**Increase External Control Area IRMs**	**12.2%**	**77.2%**	**95.7%**
	Going in the opposite direction from Case #7, this case simulates the impact on the NYCA when the respective IRM levels from neighboring control areas are greater than was assumed in the base case. Making more external capacity available for reserve sharing will reduce the IRM. The higher external control area IRMs in this case are simulated by decreasing base case peak loads by 10%.			
9	**Increase Base Case Forced Outage Rates by Representing a GADf Derate of 250 MW**	**16.4%**	**80.3%**	**99.3%**
	A Generator Availability Data Factor (GADf) derate was developed in 2004 to account for the discrepancy between a resource's reporting of its available capacity in the Generator Availability Data System (GADS) versus what was being offered into the market. For the 2005 IRM Study, the GADf derate was 711 MW; this was reduced to 125 MW for the 2006 IRM Study. Although the 2007 IRM Study represented no GADf derate, the ICS developed a 250 MW GADf derate proxy value (by doubling the previous 125 MW GADf derate) for this sensitivity case. Overstating the base case forced outage rates by derating another 250 MW serves to increase the IRM. See the "Base Case Results – Resource Capacity Availability" section of the report.			

10	**Use NYISO's Proposed (08/16/2006) Topology**	**16.0%**	**80.0%**	**99.0%**
	Not all of the original August 16, 2006 NYISO-proposed topology changes were adopted by the ICS for the base case. This sensitivity reflects the changes that would have occurred if the entire NYISO proposal were adopted. The net result of this analysis was negligible.			
11	**Model the Cross Sound Cable (CSC) as a Free-Flowing Tie (New England Capacity Increases)**	**15.1%**	**80.0%**	**93.3%**
	This case simulates when the CSC is treated as a free-flowing tie providing only emergency assistance. This was done to determine the value of the CSC tie to NYCA without capacity contracts.			
12	**No Transition Rates (Forced Outages) on Cable Interfaces**	**15.2%**	**79.4%**	**98.3%**
	This case quantifies the IRM value of the forced outage rates on these cable interfaces to the NYCA. This scenario assumes 100% availability of all the cable interfaces within the NYCA. There are currently six such cable interfaces: 1) PJM East → J, 2) Dunwoodie (I → J), 3) Y49/Y50 (I → K), 4) CE/LIPA (J → K), 5) Norwalk 1385 (K → SWCT) and 6) CSC (K → L*). The future Neptune Cable was not considered in this analysis.			
13	**Use the 2006 IRM Study Transition Rates (EFOR) for Indian Point 2**	**17.0%**	**80.7%**	**99.8%**
	The objective of this analysis is to determine the net impact of prolonged outages in the Lower Hudson Valley. This particular case used the higher-than-average forced outage rates as were used in the 2006 IRM Study. These higher rates reflected the 2000-2004 (five-year) average that included high forced outage rates experienced at Indian Point 2 during 2000. (The 2007 IRM Basecase used the 2001-2005 data, thereby dropping the 2000 data.) See the "Base Case Results – Resource Capacity Availability" section of the report.			

The 2007 IRM Study Work Plan called for evaluation of a sensitivity case for the addition of the 660 MW Neptune Cable, scheduled for service after beginning the 2007 Summer Capability Period. However, because methodology questions for conducting this study were not resolved in time to include the analysis in the 2007 Study, it was agreed to delay the Neptune Cable study till early 2007.

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 1.9 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-2.

TABLE B-2
Implementation of Emergency Operating Procedures*
Anchor Point Case Assumptions (IRM = 16.0%)

Emergency Operating Procedure	**Expected Implementation (Days/Year)**
Require SCRs	4.4
Require EDRPs	4.0
5% manual voltage reduction	3.4
30 minute reserve to zero	3.1
5% remote control voltage reduction	1.9
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-2