NEW YORK CONTROL AREA INSTALLED CAPACITY REQUIREMENTS FOR THE PERIOD MAY 2004 THROUGH APRIL 2005

New York State Reliability Council, L.L.C.

Executive Committee Resolution
And
Technical Study Report

December 11, 2003

NEW YORK STATE RELIABILITY COUNCIL, L.L.C.
APPROVAL OF NEW YORK CONTROL AREA
INSTALLED CAPACITY REQUIREMENT FOR THE PERIOD
MAY 1, 2004 THROUGH APRIL 30, 2005

1. WHEREAS, reliable electric service is critical to the economic and social welfare of the millions of residents and businesses in the State of New York; and

2. WHEREAS, the reliable and efficient operation of the New York State ("NYS") Power System is fundamental to achieving and maintaining reliability of power supply; and

3. WHEREAS, The New York State Reliability Council, L.L.C.'s ("NYSRC") principal mission is to establish Reliability Rules for use by the New York Independent System Operator ("NYISO") to maintain the integrity and reliability of the NYS Power System; and

4. WHEREAS, the NYSRC is responsible for determining the New York Control Area ("NYCA") annual Installed Capacity Requirement; and

5. WHEREAS, the study results in the Technical Study Report, dated December 11, 2003, conducted by the NYSRC Installed Capacity Subcommittee, show that the required NYCA installed reserve margin (IRM) for the May 1, 2004 through April 30, 2005 capability year is 17.1% under base case conditions; and

6. WHEREAS, in light of the Technical Study results, the modeling and assumption changes made to simulate actual operating conditions and system performance, the numerous sensitivity studies evaluated, and with due recognition that the current NYCA IRM is set at 18.0%;

7. NOW, THEREFORE BE IT RESOLVED, that in consideration of the factors addressed above, the NYSRC sets the NYCA IRM requirement at 18.0% for the May 1, 2004 through April 30, 2005 capability year, which equates to an Installed Capacity Requirement of 1.18 times the forecasted NYCA 2004 peak load.

TECHNICAL STUDY REPORT

December 11, 2003
New York State Reliability Council, L.L.C.
Installed Capacity Subcommittee

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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 Requirements (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 an engineering study conducted by the NYSRC for determining the appropriate NYCA required installed reserve margin (IRM) for the period of May 2004 through April 2005 (Year 2004) in compliance with the NYSRC Agreement. 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 ICR 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 Capacity 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.

On August 14, 2003, the Northeast experienced a Blackout affecting over 50 million people. While final results of the investigation are not yet available, the adequacy of capacity resources in New York State was not a contributing factor. The focus of the IRM study is the determination of an adequate level of NYCA resources for reliably meeting demands within the NYCA. This study makes no attempt to determine NYCA resource levels required to meet demands on the NYCA resulting from extreme contingency events.

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

Using Base Case assumptions, this NYSRC technical study resulted in a statewide IRM requirement of **17.1%**[1]. This study also presents results from various scenarios to assess the sensitivity of Base Case assumptions on the IRM. When taken together, the Base Case, sensitivity case results and other relevant factors provide the basis for the NYSRC determination of the statewide IRM requirement for Year 2004.

1 There is a 99.7 % probability that the base case result is within the range of 16.8% to 17.4%. See Appendix A.

Model improvements and updated assumptions used for the Year 2004 IRM study include:

- The NYCA load shape model has been updated using actual 2002 data. A NYISO analysis of the NYCA load shape indicates that 2002 data more closely represents current typical weather conditions. The new load shape model also captures recent zonal load growth (higher growth in NYC and LI). The model now uses the 2002 load shape, which is slightly less conservative than the 1995 load shape used in previous studies.

- No changes were warranted with the overall NYCA Load Forecast Uncertainty (LFU) model. However, to recognize the unique LFU characteristics of individual NYCA areas, the Year 2004 LFU model has been divided into three areas: New York City, Long Island, and the remainder of NYCA.

- Historic generating unit forced outage rates were reviewed and updated. For many units, these changes reflect the inclusion of historic NYCA data rather than applying NERC class averages for units with less than 10 years of operation. This results in decreasing the overall average generating unit forced outage rate. Cable transmission outage rates were also updated for this study.

- Based on operating experience, the Emergency Operating Procedure (EOP) representation was updated to include changes in the Special Case Resource, Emergency Demand Response Program, and voluntary industrial curtailment load relief values included in the EOP representation. In addition, based on recent emergency operating policy changes, emergency assistance support from interconnected Control Areas was placed near the end of the sequence of EOP steps.

The IRM requirement impacts of these and other model improvements and updated assumptions are shown in Table 1.

In addition to calculating a base case IRM requirement, the Year 2004 IRM study calculated the sensitivity of the required IRM to changes in several key study assumptions. These results are depicted in Figure 1 and in Appendix B-1.

STUDY PROCEDURE

The reliability calculation process used in 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 number of days per year of expected capacity shortages.

The General Electric Multi-Area Reliability Simulation (MARS) is the primary analytical tool 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. MARS calculates "Loss of Load Expectation" (LOLE, expressed in days per year), which provides a consistent measure of system reliability.

Appendix A includes details of the reliability calculation process, including information on the MARS program, modeling parameters, and other assumptions. The procedure used in this study is in accordance with NYSRC Policy 5-0, *Procedure for Establishing New York Control Area Installed Capacity Requirements*, www.nysrc.org/polices.html.

Sensitivity analyses were performed to determine variations to the Base Case IRM should assumed parameters change. These sensitivity analyses are used in conjunction with the Base Case to form the basis for the NYSRC determination of the statewide IRM. The findings of both the study results and the sensitivity analyses are presented in Appendix B.

RELIABILITY CRITERION

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

> *Adequate resource capacity shall exist in the NYCA such that, after due allowance for scheduled outages and deratings, forced outages and deratings, assistance from neighboring systems, NYS Transmission System transfer capability, uncertainty of load forecasts, and capacity and/or load relief from available operating procedures, the probability of disconnecting firm load due to a resource deficiency will be, on the average, no more than once in ten (10) years.*

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

STUDY RESULTS

Year 2004 IRM Base Case study results show a required statewide IRM of 17.1%. (Refer to Appendix A for Base Case study assumptions.) Accordingly, we conclude that maintaining a minimum installed reserve of 17.1% over the forecasted NYCA 2004 summer peak season will achieve applicable NYSRC and NPCC reliability criteria for Base Case study assumptions.

The major parameters that influence NYCA IRM requirements include:

- *Interconnection Support During Emergencies.* NYCA reliability can be improved by receiving emergency assistance support from other interconnected Control Areas —

in accordance with control area reserve sharing agreements during emergency conditions. Assuming such arrangements in the Base Case permits the NYCA IRM to be 6.4 percentage points lower than is otherwise required (Table B-1, Case 2 – Case 1).

- *Load Forecast Uncertainty.* It is recognized that some uncertainty exists relative to forecasting NYCA loads for any given year. This uncertainty was represented using a load forecast probability distribution based on sensitivity analysis of load levels to different weather and economic conditions. Recognizing the unique load forecast uncertainty distribution of individual NYCA areas, the load forecast uncertainty model was divided into three areas: New York City, Long Island, and the rest of New York State. Compared to single point representation, i.e., no load forecast uncertainty; the impact of this three-area load forecast uncertainty model yields a 3.2 percentage point increase in IRM. (Table B-1, Case 1 – Case 5).

- *Resource Capacity Availability.* IRM requirements are highly dependent on the availability of generating units and other types of resource capacity. An analysis was performed to update the forced, partial, and scheduled maintenance representations of the NYCA generating units included in the model to reflect 1993-2002 availability performance. To represent the capacity of gas turbines and hydro under abnormal conditions, the capacity model calibrates deratings for these types of generating units under ranges of high ambient temperature and adverse water conditions, respectively. The model for determining gas turbine temperature capacity derating was also updated for this study. In past years, NERC data for unit class type was used for units with fewer than 10 years of operation. This year, it was decided to use actual NYCA availability data for units with less than ten years of Generation Availability Data System (GADS) data. Updated generating unit and cable system EFOR's resulted in a required IRM reduction of 1.5 percentage points from last year's study. (Table 1)

- *Locational Installed Capacity Requirements.* The MARS model provides an assessment of the NYCA transmission system adequacy to deliver emergency assistance from one Zone to another in meeting specified load requirements. Previous MARS studies have consistently revealed that transmission constraints involving the New York City and Long Island Zones could impact the LOLE within these Zones, and statewide as well.

  To avoid such a LOLE impact, a minimum resource ICAP — i.e., locational ICAP — must be maintained in each of the New York City and Long Island Zones. In accordance with NYSRC Reliability Rule A-R2, *Load Serving Entity ICAP Requirements,* the NYISO is required to calculate and establish the appropriate locational ICAPs. The most recent NYISO study (*Locational Installed Capacity Requirements Study*, dated February 12, 2003) determined that the LSEs serving the New York City and Long Island Zones must maintain minimum ICAP-to-peak load ratios of 0.80 and 0.95, respectively. These minimum locational ICAP requirements were recognized in the Year 2004 IRM Base Case study.

- *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 assumed 652 MW of SCR resource capacity in July and August (and less in other months).

- *Emergency Demand Response Programs (EDRP).* EDRP allow registered interruptible loads and standby generators to participate on a voluntary basis and be paid for their ability to restore operating reserves. This study assumed 225 MW of EDRP capacity in July and August (and less in other months). The study also assumed a maximum of five monthly EDRP calls. Both SCRs and EDRP are included in the Emergency Operating Procedure (EOP) model.

Determining the appropriate IRM to meet system reliability criteria depends upon many factors. Variations from the Base Case will, of course, yield different results. Figure 1 shows the sensitivity of IRM results using several alternate assumptions. The sensitivity study results in this figure show a required IRM range of 13.9% to 23.5%. (Sensitivity case results are also listed in Appendix B, Table B-1.)

The NYISO will implement emergency operating procedures (EOPs) as required to minimize customer disconnections. If a 17.1% IRM is maintained (under Base Case conditions), firm load disconnections due to inadequate resources will not occur (on the average) more than once in every ten years — in accordance with NYSRC and NPCC criteria. (Refer to Appendix B, Table B-2, for the expected use during 2004 of SCRs, EDRP, voltage reductions, and other EOPs.)

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, this translation occurs twice during the course of each capability year, prior to the start of the Summer and Winter Capability Seasons.

Additionally, any Locational Capacity Requirements 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.

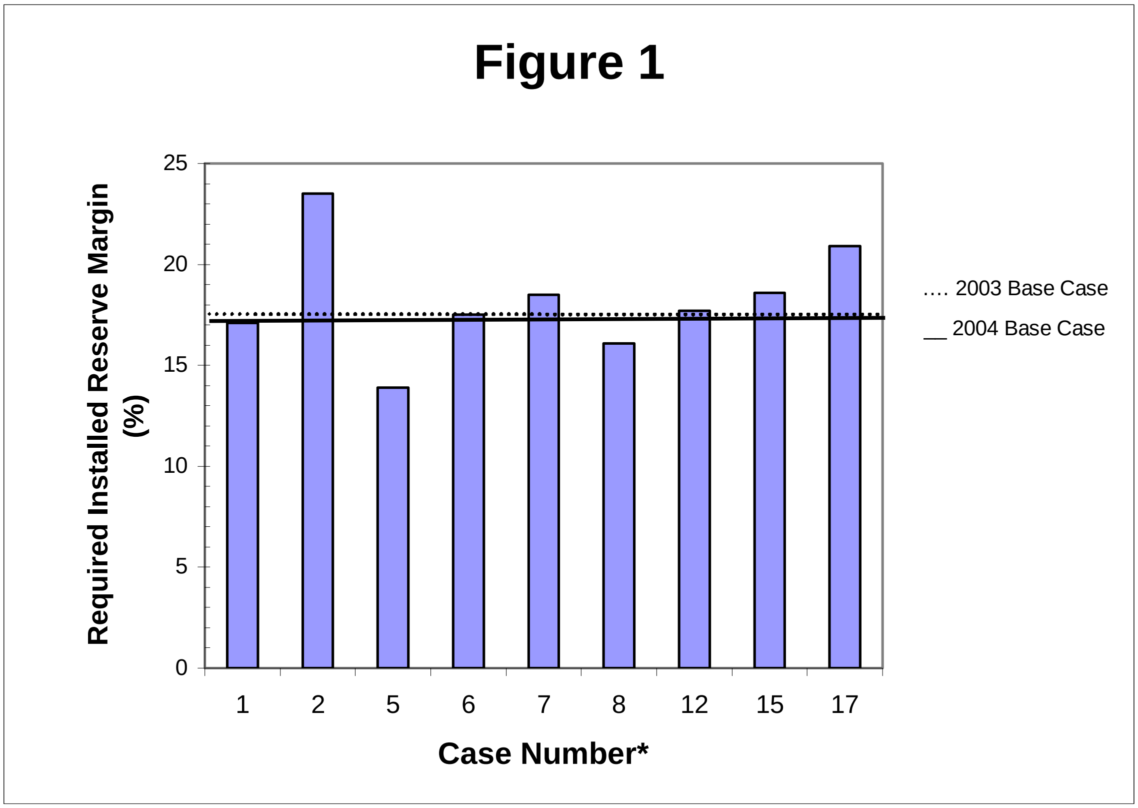
NYISO Implementation of a Spot Market Auction based on a Demand Curves:

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 installed IRM determination by the NYSRC.

COMPARISON WITH YEAR 2003 STUDY

Using Base Case assumptions including updated modeling representations, the results of this study show a required statewide IRM lower than developed for the Year 2003 IRM study. Table 1 shows the comparison of the required IRM impacts of key parameters associated with these two studies. The primary factors that change NYCA IRM requirements from Year 2003 include updated EFORs, zonal load and capacity distributions, and EOP representations. These contributing factors combined with those listed in Table 1, results in a new statewide Base Case IRM 0.4% lower than the Year 2003 IRM.



* Refers to Appendix B, Table B-1

Sensitivities – Changes from Base Case Assumptions:

Case #	Description
1	Base Case
2	NYCA Isolated
5	No Load Forecast Uncertainty
6	Without Planned Units for 2004
7	Reduce all Internal Transfer Limits by 10%
8	Reduce unit Forced outage rates by 10%
12	Remove EDRPs
15	IRM at an LOLE of 0.05 days/year (1/20)
17	IRM at an LOLE of 0.05 and no voltage reductions

Table 1

COMPARISON WITH 2003 STUDY*- NYCA

Parameter	IRM Change	IRM %
Previous Study IRM (2003 Study)		**17.5**
Updated Load Shape Model	-0.5	
Updated Load Forecast Uncertainty Model	-0.4	
Updated Zonal Load & Capacity Distributions	+1.4	
New Generating Units	-0.5	
Updated Gas Turbine Derate Model	-0.3	
Updated Generating Unit & Cable System EFORs	-1.5	
Updated EOPs (including SCRs & EDRP)	+1.0	
Updated Transmission Model	+0.2	
New Version of MARS	+0.2	
Net Change from 2003 Study	-0.4	
New Study IRM (2004 Study) Results		**17.1**

*See report titled "New York Control Area Installed Capacity Requirements for the period May 2003 through April 2004", dated January 10, 2003, for 2003 study model description and assumptions.

APPENDIX A

NYCA INSTALLED CAPACITY REQUIREMENT RELIABILITY CALCULATION MODELS AND ASSUMPTIONS

Description of 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 (MARS) is the primary computer program used for this probabilistic analysis. The result of the calculation is termed "Loss of Load Expectation" (LOLE), which provides a consistent measure of system reliability. The relationship between MARS and the various models used in the NYCA IRM calculation process is 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 2003 and 2004 IRM reports.

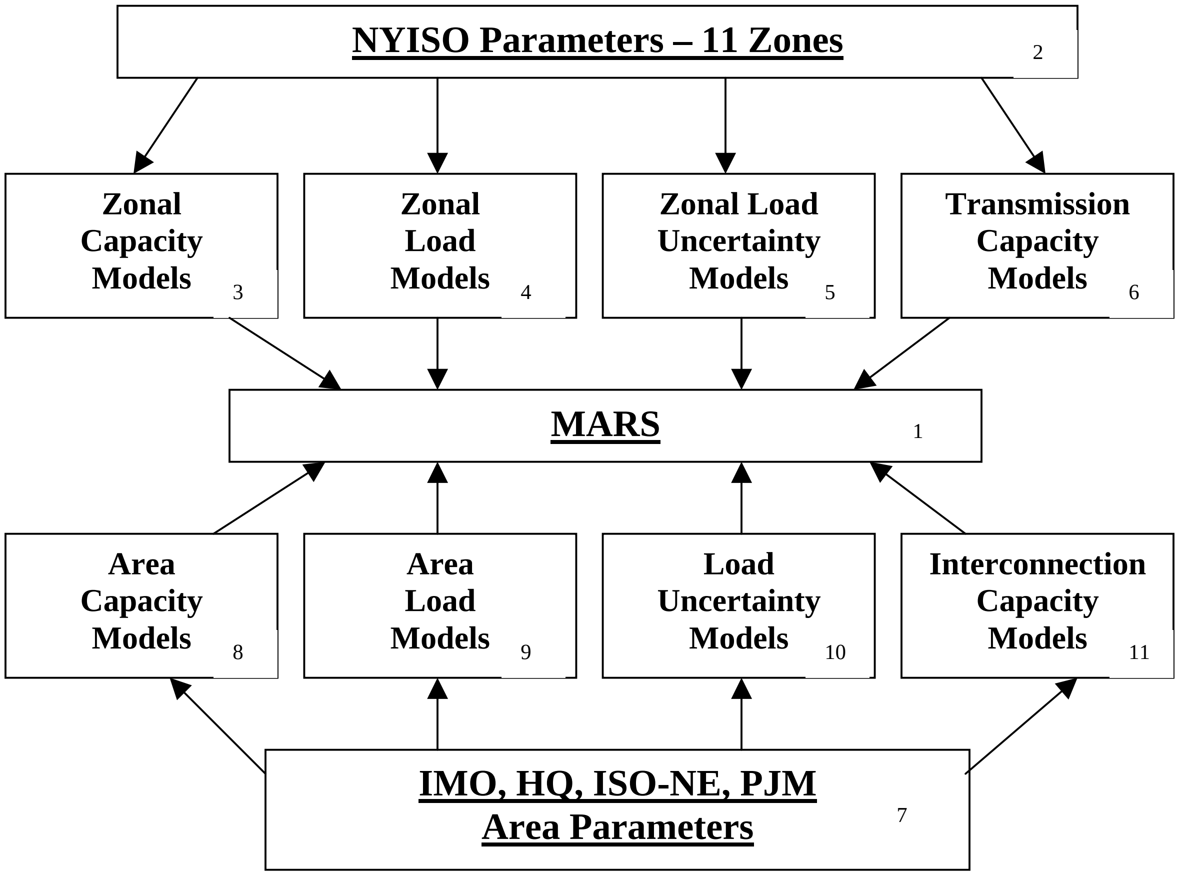
Table A-1
Details on Study Parameters

Figure A-1 Box No.	Name of Parameter	Description	Source	Reference
1	MARS	The General Electric Multi-Area Reliability Simulation Program		See page 12
2	11 Zones	Load Areas	Fig. A-2 page 15	NYISO Accounting & Billing Manual
3	Zone Capacity Models	Generator Models for each generating unit in Zone.		See page 20
		Generating Availability.	GADS Data	See page 20
		Unit Ratings.	2003 Gold Book[1]	
	Emergency Operating Procedures	Reduces load during emergency conditions to maintain operating reserves.	NYISO	See page 29
4	Zone Load Models	Hourly loads	NYCA load shapes. NYISO peak forecasts.	See page 17 31,890 MW Gold Book
5	Load Uncertainty Model	Account for forecast uncertainty due to weather and economic conditions.	Historic Data	See page 19
6	Transmission Capacity Model	Emergency transfer limits of transmission interfaces between Zones.	NYISO transmission studies	See page 30
7	IMO, HQ, ISO-NE, PJM control area Parameters	See the following items 8-11.		
8	External Control Area Capacity Models	Generator Models in neighboring control areas	NPCC CP-8 study for NPCC Areas. NERC Report for PJM	See page 33
9	External Control Area Load Models	Hourly Loads	NPCC CP-8 study for NPCC Areas PJM Web site.	See page 18
10	External Control Area Load Uncertainty Models	Account for forecast uncertainty due to weather and economic conditions	NPCC CP-8 Study	See page 34
11	Interconnection Capacity Models	Emergency transfer limits of transmission interfaces between control areas.	NPCC CP-8 Study	See page 30

1. "2003 Load & Capacity Data" Report issued by the NYISO.

Figure A-1

NYCA ICAP Modeling



A-2 Computer Program Used for Reliability Calculation

The primary tool used in the probabilistic analysis for establishing NYCA IRM requirements is a General Electric computer program called the Multi-Area Reliability Simulation (MARS). This 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 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 and demand-side options.

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, MARS also produces probability distributions that show the actual yearly variations in reliability that the NYCA could be expected to experience.

In determining the reliability of the NYCA 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.

A sequential Monte Carlo simulation, the approach used by MARS, steps through the year chronologically, recognizing the fact that the status of a piece 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. The 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 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 a given hours 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:

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

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.

The number of replications simulated is determined such that the standard error of the estimate of the LOLE is 0.05. This year, the standard error in LOLE results in a +/-0.3 percentage point IRM range for a Base Case confidence interval of 99.7%. . Twenty five hundred and nine (2,509) replications were simulated in the Base Case.

A-3 Representation of the NYCA Zones

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

A-4 Conduct of the MARS Analysis

An updated MARS software version was tested to ensure that the new version produced acceptable results. Such tests normally compare results for reasonableness with study results from a previous MARS version using same assumptions.

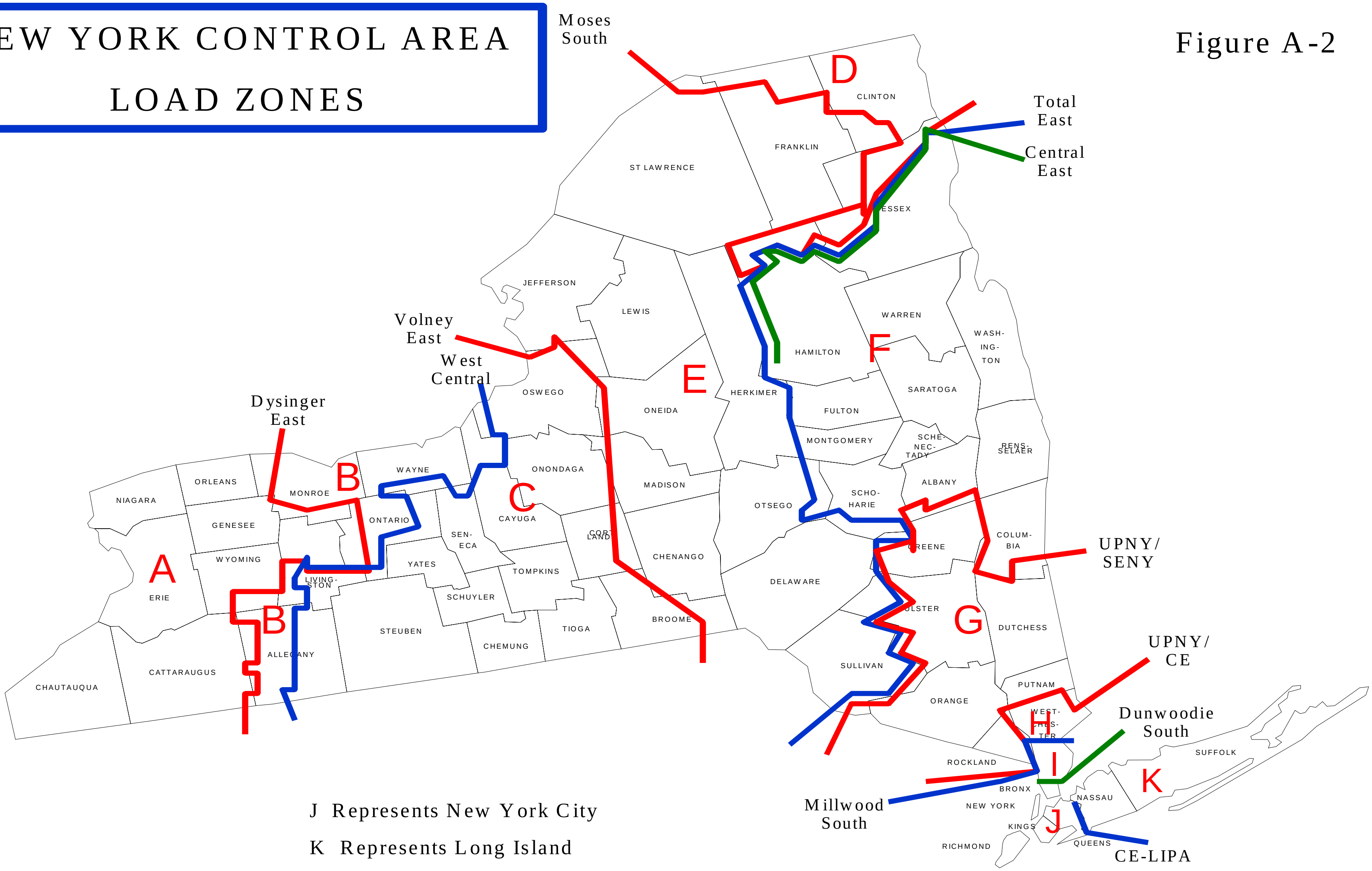
The base case is developed by starting with the previous year's base case and inputting base case changes one parameter at a time. The LOLE results of each of these pre-base case simulations are reviewed to confirm that the reliability impact of the change is reasonable and explainable.

Below are the primary study parameters that are input into the MARS program. These parameters are described in detail in Section A-5 and referenced in the boxes shown in Table A-1 and Figure A-1.

1. All known generators for all modeled Areas and their associated MW ratings and transition rates. (See Figure A-1 Boxes 3 and 8)
2. The transfer limits of the transmission system between Zones and/or Areas (across the interfaces between the Zones and/or Areas) in both directions. (See Boxes 6 and 11)
3. Groupings of interface flows that would limit the total flows to less then the sum of the individual flows in or out of an Area. (See Box 6)
4. The transition rates for the cable interfaces. (See Box 6)
5. The 8760 hourly loads for each of the Zones and Areas. (See Boxes 2, 4 and 9)
6. The list of emergency operating procedures. (See Box 3)
7. All firm transactions between Areas and Zones, including an estimate of the amount of generation external to NYCA that will that will count as firm capacity. (See Box 3)
8. Generator maintenance schedules. (See Box 3)
9. The load forecast uncertainty probability table. (See Boxes 5 and 10)

NEW YORK CONTROL AREA LOAD ZONES

Figure A-2



J Represents New York City

K Represents Long Island

The peak loads of all Areas are aligned to be on the same day, 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.

After the base case data and models are fully input into the MARS program, an initial reliability simulation is run and the LOLE result compared to the LOLE criterion target of disconnecting firm load once in 10 years, or 0.1 days per year. If there is not a match, MARS is re-run in an iterative process by increasing/decreasing the loads in the Zones proportionally in order to yield a higher/lower LOLE result, until the result matches the 0.1 days per year LOLE target. This final case defines the base case from which the required NYCA IRM is determined. This iterative process is also used for the pre-base case simulations described above.

An alternative to changing load to arrive at the target LOLE is to remove generation. However, if generators are removed the question arises as to which type of generators should be removed and from what location. By raising the load as described above, the generation mix remains unchanged.

A final step is to check that none of the surrounding Areas are more reliable then NYCA on an isolated basis. If they are, then their loads are increased until this is no longer the case. This is done so that NYCA is not overly dependent on its neighboring systems. A final iteration of the NYCA load gives the desired 0.1 days/yr.

From this, the NYCA generating capacity modeled minus net sales is divided by the peak NYCA load to determine the IRM.

In addition to running a base case using the input assumptions described below, a number of sensitivity studies are run to show the IRM requirement outcomes for different assumptions.

A-5 Input Data and Models

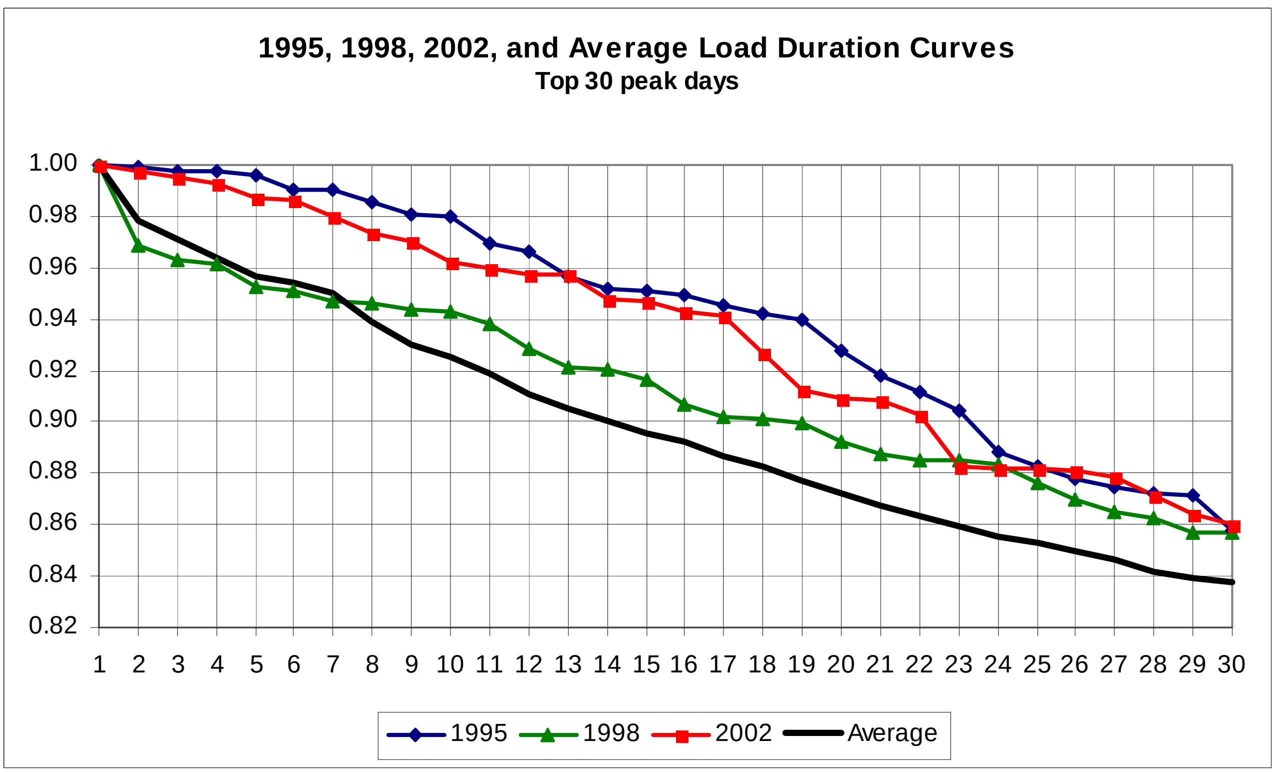
A-5.1 NYCA LOAD MODEL

An 8,760-hour chronological model is input to the MARS program for each Control Area or Zone modeled. Over the past several years, the IRM study has been performed using the 1995 hourly loads.

The NYISO Load Forecasting group provided information to the ICS on the factors effecting load shape and the characteristics of the load shapes that have occurred since 1993. In addition, this year the group provided detailed analysis on weather characteristics. The ICS decided to use the 2002 load shape instead of the previously used 1995 load shape. This was based on the 1995 load shape being less desirable for four reasons: 1) the load shape itself in antiquated, 2) the zonal components do not adequately represent recent load growth patterns, especially in downstate areas, 3) the 1995 shape falls outside weather design criteria by greater than one standard deviation, and 4) the 1995 shape has a high temperature excursion outside of the expected peak period. These characteristics are explained in more detail below.

Figure A-3 shows that 2002 falls between the 1995 load shape and the 1998 load shape for number of daily peaks near the annual peak. The average curve is derived from the years 1993 through 2002, excluding the years 1996 and 2000 that were atypically cool.

Figure A-3



In Addition, the 1995 load shape was recognized as becoming dated and not reflective of the late 1990's pattern of economic growth in New York, which has focused principally on New York City and Long Island. The data in the following table shows this:

	Share[1)] 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%

1) Average of current and preceding two years.

The load shape for a Zone that is input into MARS is an hourly aggregate of sub-Zone loads. Sub-Zone loads in NYCA are developed by applying appropriate weights to the Transmission District load shapes.

Each Control Area's (the IMO, HQ, ISO-NE and NYISO) load forecast for the study year is based on its base case load shape, updated to reflect its most recent peak load forecast. The NYCA forecast 2004 peak load used for this study is the most recent estimate of 31,890 MW.

Weather Analysis

The ICS also reviewed analyses of summer weather patterns in evaluating which year to use as the load shape for the 2004 IRM study. The following table shows how close each year's peak conditions were to design (NYISO Weather Index = 81.57). The years are grouped by whether or not their experienced peak condition was within one standard deviation of design. 2002 was in that range while 1995 was not. Design basis is the median of 30 years worth of extreme values of combined temperature humidity index. This index is based on 60% dry bulb temperature and 40% wet bulb temperature.

Years where ISO Index Fall Within Design +- 1 σ

(81.57 +- 2.32)

Year	ISO Index
1993	83.2
1994	83.1
1997	83.2
1998	83.1
2002	83.3

Years where ISO Index Falls Outside of Design +- 1 σ

Year	ISO Index
1995	84.9
1996	77.5
1999	84.3
2000	77.4
2001	84.3

In fact, 1995 had the most extreme peak conditions of any year examined.

Figure A-4

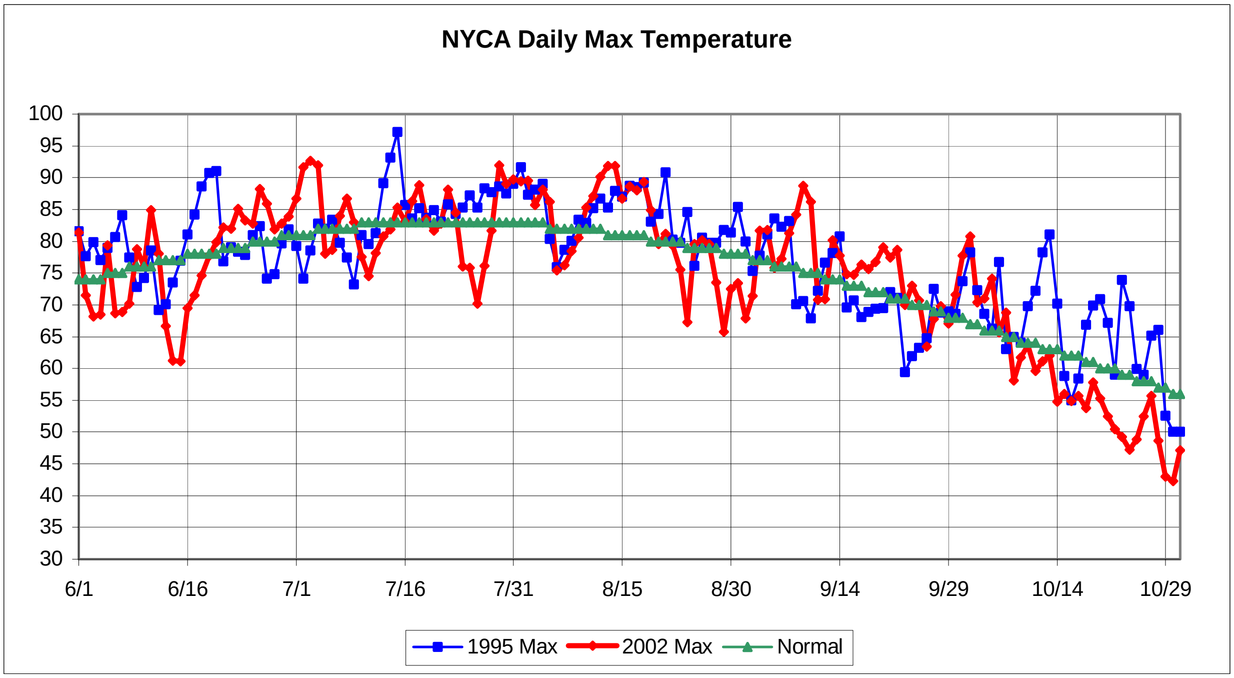


Figure A-4 shows the pattern of New York State daily high temperatures for 1995, 2002 and normal. Both years show several above normal excursions during the typical peak load period (about July 7 through August 15). However, the July 15 excursion for 1995 was the highest of the years studied. A secondary excursion in mid-June for 1995 is also significantly atypical.

Based on these considerations, the ICS concluded that the 2002 weather was more typical than 1995.

A-5.1.1 Zonal Load Forecast Uncertainty

Load forecast uncertainty (LFU) covers both the uncertainties of weather and load growth as they affect the load forecast. A load forecast distribution is used to represent this uncertainty in the MARS model. This year, the ICS was able to include separate LFU models for Zones J, K and the rest of New York. The models are presented below.

Zonal Load Forecast Uncertainty Models

Multiplier	NYCA Tot	Con Ed (J)	LIPA (K)	NYCA Net
0.0062	1.0584	1.0480	1.1420	1.0394
0.0606	1.0499	1.0386	1.0887	1.0300
0.2417	1.0250	1.0176	1.0444	1.0206
0.3830	1.0000	1.0000	1.0000	1.0000
0.2417	0.9770	0.9683	0.9556	0.9852
0.0606	0.9460	0.9486	0.9113	0.9551
0.0062	0.9070	0.9404	0.8580	0.8995

Data for J was obtained from Consolidated Edison and for K from LIPA. The NYCA Net (i.e., A – I) was determined by taking out the load weighted J and K contribution to uncertainty form the NYCA Total uncertainty. Load forecast uncertainty for the State, as a whole was unchanged.

CCA-5.2 NYCA Capacity Model
The capacity model input to 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 "2003 Load and Capacity Data" (Gold Book) was published:

- **<u>Retirements:</u>**
  None

- **<u>New Units: (Units installed during 2003)</u>**
- Far Rockaway GT2 – 54 MW, Long Island
- Greenport GT1 – 46 MW, Long Island
- Athens Generating Station – 1080 MW, Zone F

- **<u>Planned Units for 2004</u>:** (These units had a signed interconnection agreement by August 1, 2003.)
  KeySpan Ravenswood – 250 MW, NY City
  Freeport 1 – 47 MW, Long Island
  EQQUS Freeport – 44 MW, Long Island
  Flat Rock Wind Power – 240 MW, Zone E is modeled as a sensitivity because the in service date is the fall of 2004 (preliminary data).

This section describes how each resource type is modeled in 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 2003 NYCA Load and Capacity Report, issued by the NYISO, is the source of those generating units and their ratings included on the capacity model. This year the Athens power station is modeled as multiple units. The modeling of the Athens units also incorporates the modeling of dynamic transmission interface limits.

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. The source of this data is outage data collected by the NYISO from generator owners using availability data reporting requirements in the NYISO Installed Capacity Manual. The multi-state model for each unit is derived from ten years of historic events if it is available. For units with less then ten years of historic events, the three 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 ten-year average NERC - Generating Availability Data System (GADS) outage data collected by NYPP and the NYISO for the years 1993 through 2002. 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 MARS program.

A detailed analysis of all the NYCA units' equivalent forced outage rates was performed and confirmed that the continuing use of the ten-year historic forced outage rate data was appropriate. There is no obvious difference in any trends when looking at the five and ten year data. Using ten years of data is more likely to capture uncertainties in the forced outage rates.

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 period used to determine EFORd averages.

Figure A-5

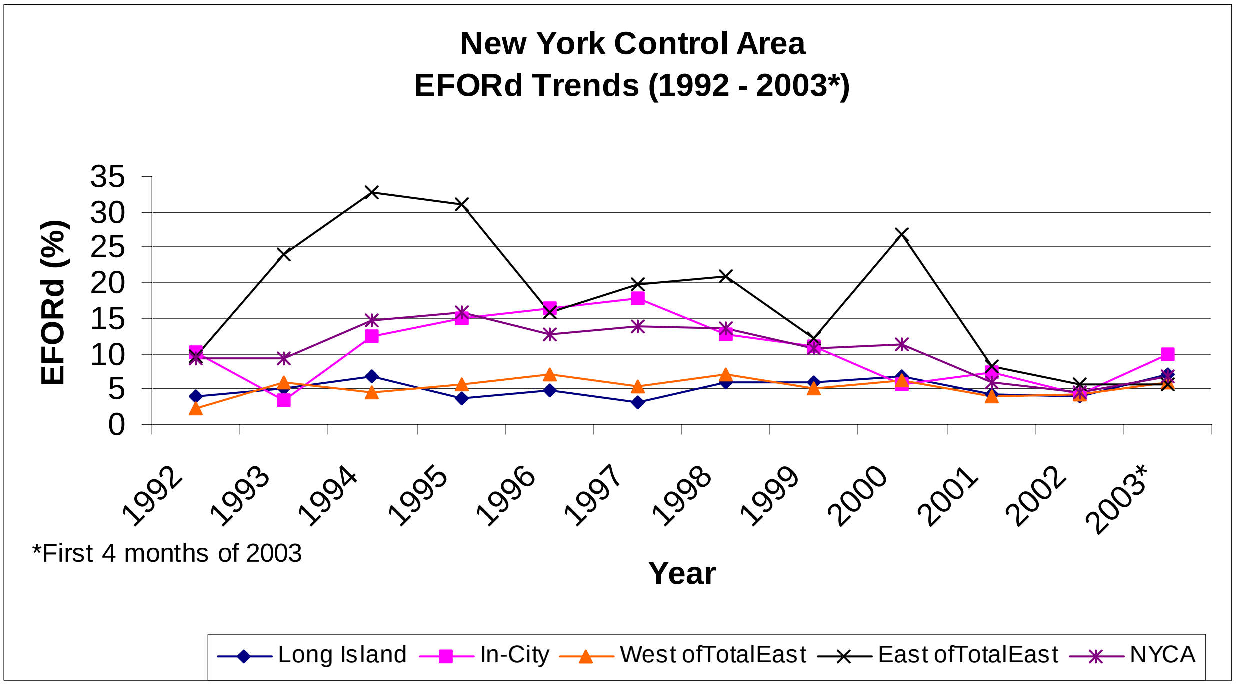


Figure A-5 provides a graph of Equivalent Forced Outage Rates under Demand (EFORd) from 1993 through the first four months of 2003. The graph presents unit weighted averages for four Zones within the NYCA along with a NYCA total aggregate. Due to a slight increase in EFORd during the first part of 2003, the ICS decided to continue with a ten-year historic outage rate period. Another factor supporting this decision was the consideration of unrecorded transmission outages such as those arising from step up transformers and radial generator exits.

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 are no significant upward or downward trends for the types of generator units modeled in the study. Therefore, the Working Group concluded that the ten-year historic outage rates are appropriate for this study.

While NYCA data prior to the formation of the NYISO includes unit unavailability due to transmission outages, recent data collection does not include these elements—and may slightly overstate availability. The NYISO is currently developing procedures and software to incorporate outages associated with generator leads and Generator Step-Up (GSU) transformers.

Figure A-7 provides NERC-GADS data industry-wide. Again, there does not appear to be any significant upward or downward trend present. Note that the year 2002 data from NERC is not available at this date.

Figure A-6

NYCA EQUIVALENT AVAILABILITY

BASED ON NERC-GADS DATA FROM 1982 – 2002

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

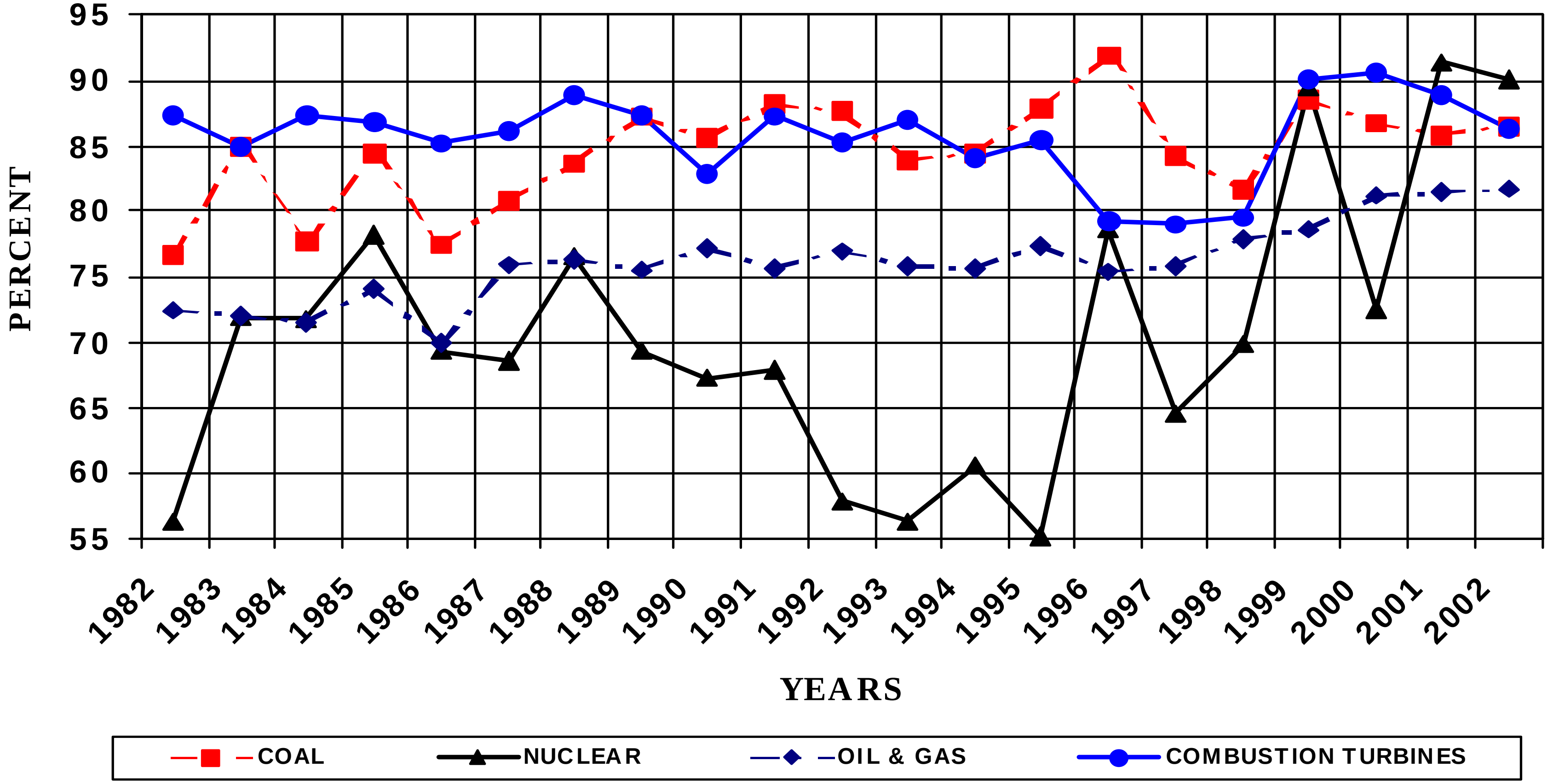
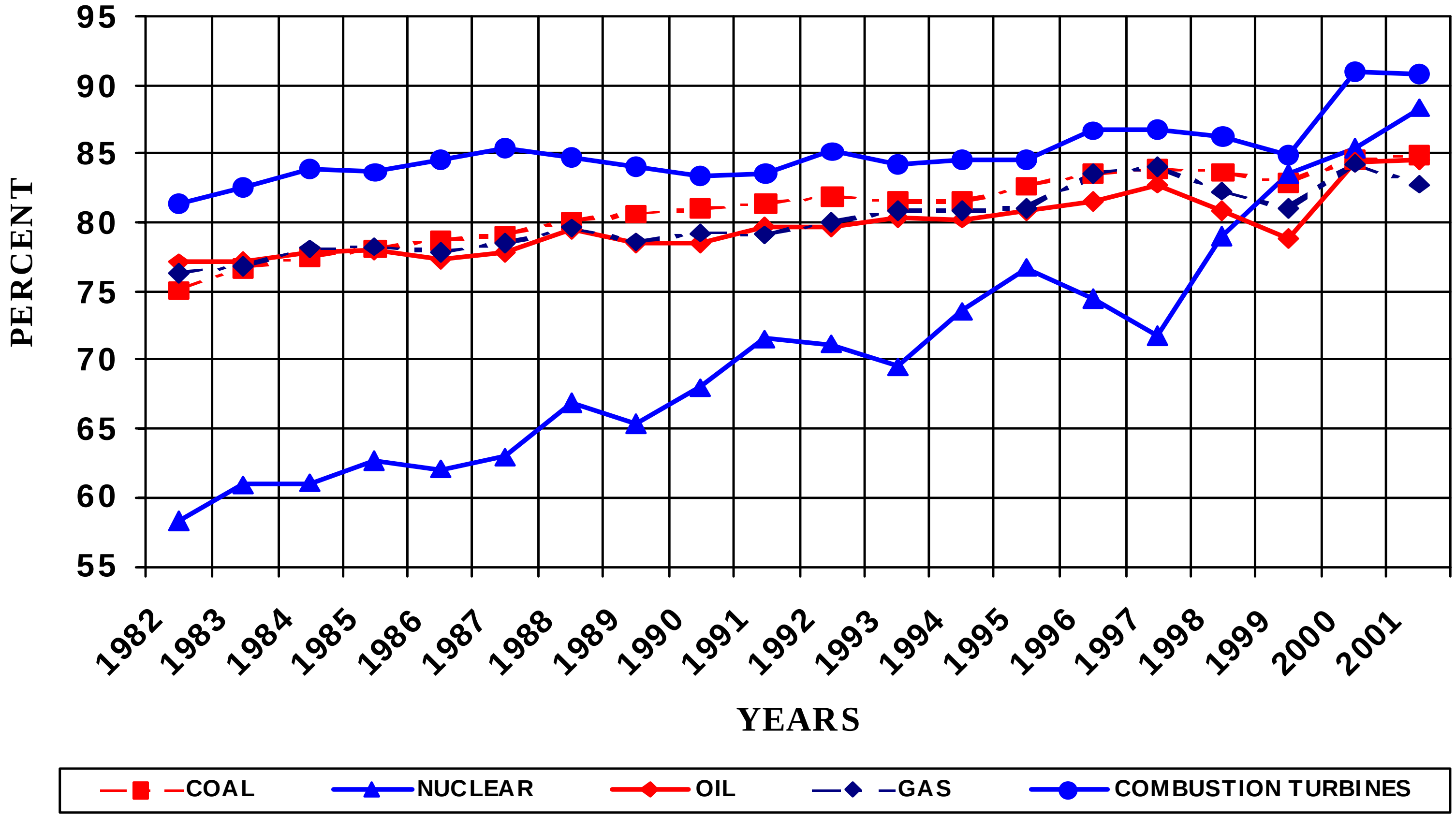


Figure A-7

NERC EQUIVALENT AVAILABILITY

BASED ON NERC-GADS DATA FROM 1982 - 2001

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



Scheduled Maintenance. The total amount of scheduled maintenance including both planned and maintenance outages, was developed from a ten-year average of the same NERC-GADS data used to obtain the forced outage rates.

The forecast of the planned outages for the study period were obtained from the generation owners, and where necessary, the length of the outage was extended so that it equaled the ten-year historic outage time period. Figure A-8 provides a graph of scheduled outage trends over the 1993 through 2002 period for NYCA generators.

Figure A-8

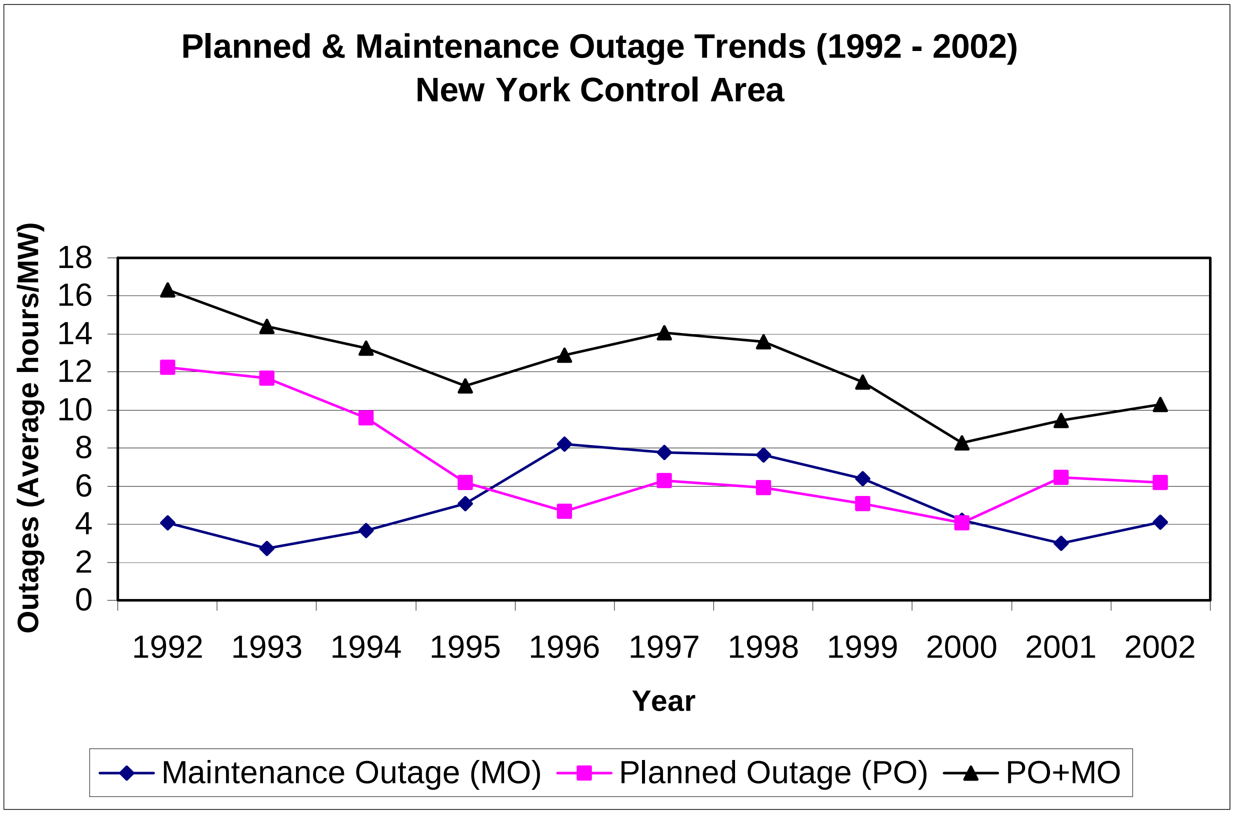
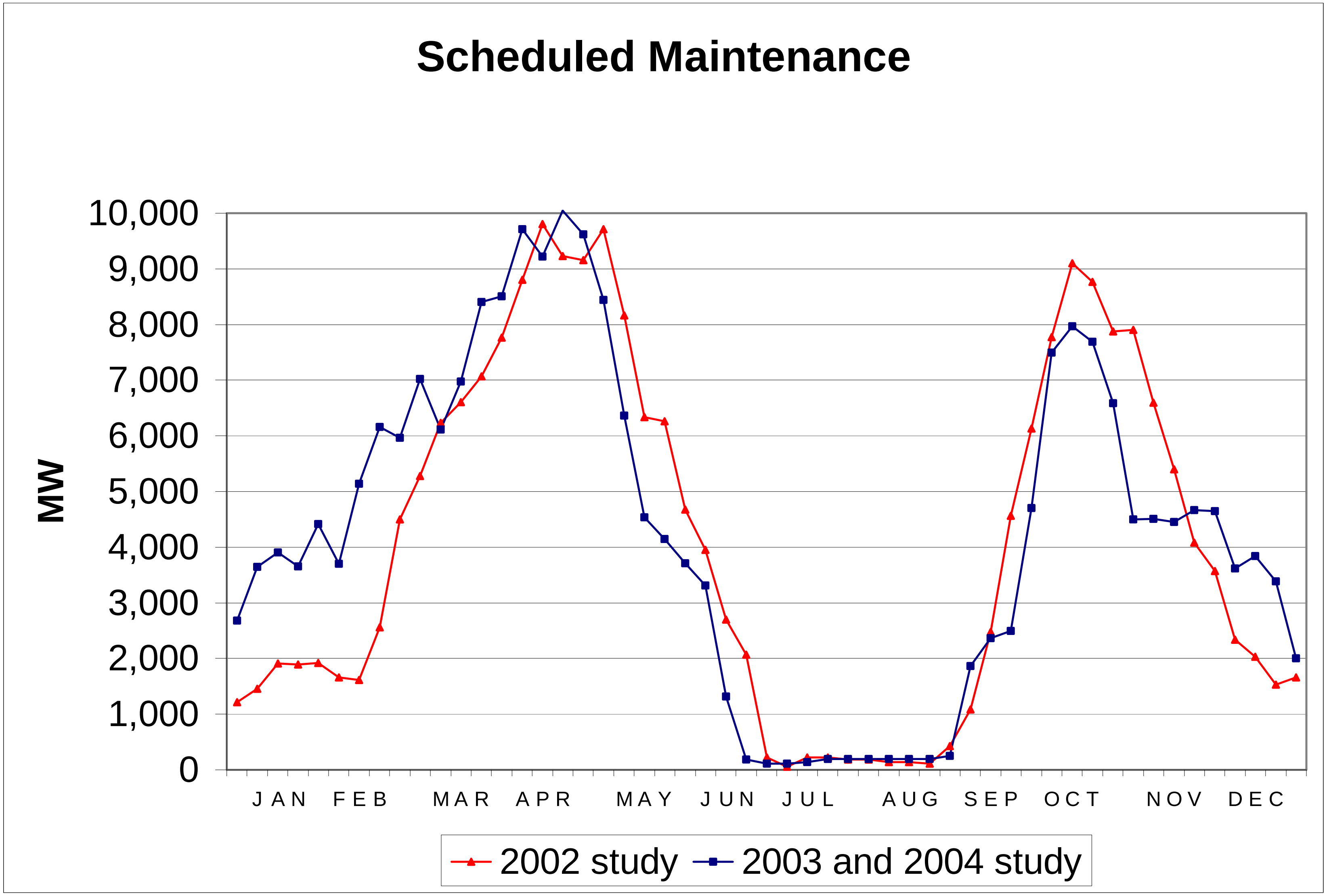


Figure A-9 shows the amount of capacity assumed to be on scheduled outages in the 2002 and 2003 studies. Since no updates to the scheduled maintenance were available when this study was done, the 2003 data is being used for the 2004 study.

The planned outages in the current study over the 2004 summer period range from 114 MW to 253MW.

Figure A-9


Scheduled Maintenance
MW
10,000
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
2002 study
2003 and 2004 study

Combustion Turbine Units. An updated model of combustion turbine derating due to temperature in excess of DMNC test conditions was developed based on two parameters, the first relates NYCA load to temperature; the second relates combustion turbine deratings to temperatures above DMNC conditions.

The NYISO's Load Forecasting staff provided the NYCA load to temperature relationship. It was determined that the NYCA load increases by approximately 250 MW per degree above normal design conditions of 92° F. An analysis was performed to determine the derating of combustion turbine units based on higher then expected temperatures. It was determined that combustion turbines derates amounted to 640 MW due to the 100° F downstate temperatures experienced over the summer 2001 peak. DMNCs are normally set at normal design condition temperatures around 92° F. Thus, the 640 MW derate over an eight degree spread produces a derate of 80 MW per degree F. This same derate was found using the summer 2002 data. This value is still appropriate for use this year even though there are more combustion turbines. This is because 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.

This derate is captured in the model at those load levels above the system forecast peak of 31,890 MW. For example, all 640 MW of derate are modeled at the highest load level. A proportional amount is modeled at the two lower load levels that are below the highest yet above the unity load level.

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 hydro facilities are represented in MARS with a 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.

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

For this year's study the NYISO has recommended that SCRs be modeled as a 652 MW EOP step, discounted to 600 MW in July and August (and further discounted in other months proportionally to the monthly peak load). EDRP are modeled as a 225 MW EOP step with a limit of five calls per month. This EOP is discounted based on actual experience from the forecast registered amount of 900 MW.

It is noted that Appendix B, Table B-1 Case 13, shows a marginally lower IRM for the case where all SCRs where removed. This is attributable to slightly different availability and locational characteristics of SCR capacity relative to the existing NYCA capacity characteristics. This does not imply that SCRs increase the probability of disconnection when activated in operation. Conversely Appendix B, Table B-1 Case 13a, shows that when SCRs are added to transmission constrained Zones J & K the IRM is reduced.

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:

There is 227 MW of grandfathered summer capacity modeled as firm purchases by NYCA, consisting of 117 MW from PJM, and 55 MW from New England and 55MW from Ontario. The Base Case assumes the following additional summer external ICAP: 1200 MW from HQ, 345 MW from New England and 983 MW from PJM. The New England to Long Island (Cross Sound Cable) tie is modeled with a 305 MW firm purchase. This totals 3,060 MW of expected summer external ICAP (2,755 MW without the Cross Sound Cable tie). The expected amount of external ICAP for the winter is 2331 MW.

NYISO studies have indicated that the maximum external ICAP that can be purchased without impacting reliability is 3060 MW.

All firm sales are modeled as listed in the Gold Book for the year 2004.

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	652 MW*
2	Emergency Demand Response Prog.	Load relief	225 MW
3	5% manual voltage Reduction	Load relief	81 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	487 MW**
6	Curtail Company use	Load Relief)	60 MW
7	Voluntary industrial curtailment	Load relief	143 MW**
8	General public appeals	Load relief	10 MW
9	Emergency Purchases	Load relief	Varies
10	Ten-minute reserve to zero	Allow 10-minute reserve to decrease to zero	1200 MW
11	Customer disconnections	Load relief	As needed

* *The SCR's are modeled as 652 MW, however they are discounted to 600 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 2004 peak load of 31,890 MW.*

The above values are based on the year 2003 results associated with a 2004 peak load forecast of 31,890 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. In this year's study, the emergency purchases have been moved from step 1 to step 9 to more accurately reflect current actual emergency operation procedures.

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 MARS program.

The values for the voluntary industrial curtailment and public appeals are reduced from those used last year to reflect the increase in the customers participating in the paid programs (SCR and EDRP).

A-5.4 Transmission Capacity Model

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 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 MARS program, a transportation algorithm is utilized with limits on the interface ties between the Areas and Zones represented in the model. Recent enhancements to the MARS program, such as interface tie groupings and dependent interface tie limits, have allowed for a simplification of the network topology employed in the MARS model. This simplification more closely resembles the standard eleven-Zone NYCA model and the standard interface ties and allows for the removal of the "Dummy Zones" that were employed in the past. 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 MARS representation. The new topology and interface limits are shown in Figure A-10.

The interface tie limits used in the 2003 IRM study were reviewed to assess the need to update the limits resulting from more recent studies and the recent topology simplification. The Summer 2002 and 2003 Operating Study Reports and databases, and the 2001 and 2002 Area Transmission Reviews and databases were used in the assessment. When the results in the above reports were not sufficient to make an assessment, additional analysis was done with the databases. Most of the limits reported in the above studies that differed from 2003 IRM diagram were different for base case conditions and study assumptions rather than a change in transfer capability, and thus do not need updating. Exceptions to the above include the following:

- The Rockland Electric Company (RECO) load was removed from the NYCA representation. Since this load is radially connected to the NYCA, its impact is reflected by a 400 MW reduction in the appropriate transfer limits.

- The Central East including Fraser-Gilboa limit (Zone E to Zone F) of 3250 MW was derived from the Central East Limit (2750 MW) minus the PV20 flow (150 MW) plus Fraser-Gilboa (650 MW limit based on relative shift factors to Central East).

- The CE group limit represents the simultaneous limit of Central East and Marcy South, and serves to limit an overly optimistic Central East plus Fraser-Gilboa distribution.

- The Total East Limit is the simultaneous limit of the grouping of all of the interface ties comprising Total East.

- The UPNY/SENY grouping was modified to only include the Zone F to G and Zone E to G interface ties. This limit was also made sensitive to the availability of the Athens Plant. The Athens Plant was modeled as three units, with a reduction of the grouping limit of 133 MWs per unit, for a total of a 400 MW decrease if Athens is fully available.

- The NE/SENY grouping limit represents an average flow distribution of 50% on the NE to G and 50% on the NE to F interface ties, and limits loop transfers through NE.

- The Total East grouping replaces most of the dummy Zones and summing junctions.

Cable Interfaces

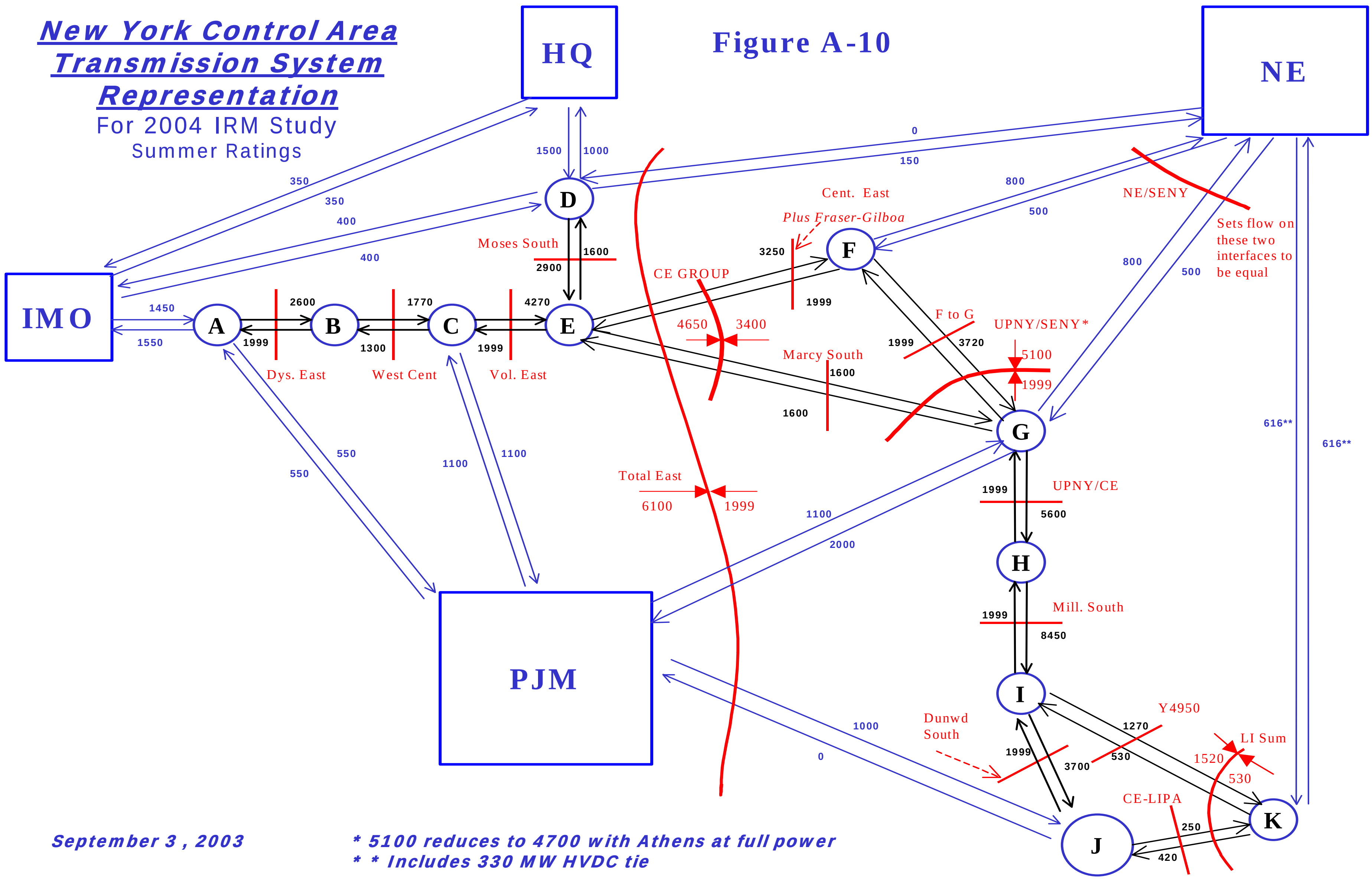
Failure rates for overhead lines and underground cables are similar but the repair time for an underground cable is much longer. Therefore, forced transmission outages are included in the MARS model for the underground cable system from surrounding Zones entering into New York City and Long Island. The 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, a failure rate for each cable is calculated on a per-mile basis using the entire Consolidated Edison underground electric system history from 1988 to the present on a voltage class basis. Typically, the more years included and 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. Industry standard data is used for a conservative estimate of expected failures on each transformer and phase angle regulator. 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 transition rates for the three transmission interfaces into New York City, and the Long Island – Con Edison interface were recalculated. In addition, a forced outage rated was introduced on the Long Island feeder #1385 intertie line to New England utilizing the above methodology. The transition rates associated with the New York City interfaces did not change from what was previously utilized. These assumptions remain valid and the failure rates and repair times are still considered accurate and conservative. Transition rates for the Long Island – Con Edison cable interface were revised to reflect increased unavailability of Long Island interties.

Interconnection Support During Emergencies

Base case assumptions considered the full capacity of transfer capability from external ISOs (adjusted for grandfathered contracts and estimated external capacity purchases) in determining the level of external emergency assistance. During 2003, an event occurred where the interface with New England was reduced for a significant period of time. The interface has been subsequently reinforced. Table B-1, Case # 11, presents the result of a sensitivity case with no external emergency assistance from New England and shows a 0.7 percentage point increase in the IRM.



New York Control Area
Transmission System
Representation
For 2004 IRM Study
Summer Ratings
Figure A-10
HQ
NE
IMO
PJM
A
B
C
D
E
F
G
H
I
J
K
Moses South
Dys. East
West Cent
Vol. East
CE GROUP
Cent. East
Plus Fraser-Gilboa
NE/SENY
Sets flow on these two interfaces to be equal
F to G
UPNY/SENY*
Marcy South
Total East
UPNY/CE
Mill. South
Dunwd South
Y4950
LI Sum
CE-LIPA
September 3 , 2003
* 5100 reduces to 4700 with Athens at full power
* * Includes 330 MW HVDC tie

A-5.5 Locational Capacity Requirements

The 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. The Locational Installed Capacity Requirements Study performed by NYISO determines LSEs requirements for affected Zones. These minimum locational ICAP requirements are recognized in the NYSRC IRM study base case representation. Currently these are 95% for Long Island and 80% for New York City.

Intra-zonal transmission constraints are addressed in the annual NYISO Locational Installed Capacity study for determining LSE ICAP requirements. The statewide ICR study considers intra-zonal transmission constraints through the modeling of locational capacity requirements of constrained Zones. This ensures that transmission constraints, both into a Zone and internally within a Zone, are considered and do not impact NYCA capacity requirements.

A-5.6 Outside World Load and Capacity Models

The reliability of NYCA depends on a large extent on emergency assistance from its interconnected Control Areas in NPCC and PJM, based on reserve sharing agreements with the Outside World Areas. Therefore, load and capacity models of the Outside World Areas are represented in the MARS analyses. The load and capacity models for ISO-NE, IMO and Hydro-Quebec are based on data received from the Outside World Areas, as well as NPCC sources. The PJM capacity model is based on data from the NERC Electric Supply and Demand database.

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. 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.

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 NPCC Control 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).

The PJM capacity model is based on the 1998 NERC Electric Supply and Demand database. Unit availabilities are based on Weighted Equivalent Availability Factors, by unit size and fuel type, from the NERC Generating Unit Statistical Brochure. PJM's load model is based on its actual 2002 load shape.

The EOPs were removed from the ISO-NE and IMO 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 is from the CP-8 study.

A-6 Assumption Summary

COMPARISON OF ASSUMPTIONS USED IN THE 2003AND 2004 REPORTS

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	2003 REPORT	2004 REPORT
NYCA Capacity	All Capacity in the NYCA	All Capacity in the NYCA
NYCA Unit Ratings	Based on 2002 Gold Book	Based on 2003 Gold Book
Planned Capacity	Updated to time of study	Current, See Page 20
Forced and partial outage rates	NERC-GADS 1992-2001	NERC-GADS 1993-2002. In most cases 3 year historic data has replaced NERC class average data
Planned outages	Based on schedules received by NYISO as of Sept. 2002 & adjusted for history	Same as last year. New information not available in time for study
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 – all except PJM	NPCC CP-8 2001 Study	NPCC CP-8 2001 Study
Neighboring Control area – PJM	Developed from public information	Same as last year
Load Model	Base Case NYCA shape (1995)	2002 NYCA shape
Peak Load Forecast	Gold Book forecast of 31,330 MW	Gold Book forecast of 31,890 MW
Load Model Uncertainty	Includes updated load growth uncertainty model	Includes improved uncertainty model that models three Areas of NYCA separately
External ICAP	Grandfathered plus 600 MW from HQ and a 500 MW wheel from HQ to New England	Grandfathered plus 1200 MW from HQ, 345 MW from New England and 983 MW from PJM
Emergency Operating Procedures	1824 MW load relief (Includes 560 MW SCRs and 354 MW EDRPs)	1658 MW load relief (Includes 652 MW SCRs and 225 MW EDRPs)
Locational Capacity Requirements	Used results from 2002 NYISO Locational Requirements Study	Used results from 2003 NYISO Locational Requirements Study
Transfer Limits	2002 NYISO Assessment	2003 NYISO Assessment

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APPENDIX B

DETAILS OF STUDY RESULTS

B-1 Introduction

Appendix B provides details of the MARS case results referenced in the body of this report. This includes results of the base case and various sensitivities cases, as well as an analysis of emergency operating procedures for the base case required IRM.

B-2 Base Case and Sensitivity Case Results

Table B-1 summarizes the 2004 capability year IRM requirements under base case assumptions, as well as under a range of assumption changes from the base case. The base case utilized the computer simulation, reliability model, and assumptions described in Appendix A. The sensitivity cases determined the extent of how the base case required IRM would change for assumption modifications, either one at a time, or in combination.

TABLE B-1
STUDY RESULTS

Case #	Description	NYCA Ext ICAP Rep.(MW)	IRM[1]
1	**Base Case [2]**	**3060**	**17.1 %**
2	NYCA Isolated	0	23.5 %
3	No External ICAP	0	17.1 %
4	Grandfathered External ICAP Only	227	17.1 %
5	No Load Forecast Uncertainty	3060	13.9 %
6	Without planned units for 2004	3060	17.5 %[3]
7	Reduce All Internal Transfer Limits by 10%	3060	18.5 %
8	Reduce unit forced outage rates by 10%	3060	16.1 %[4]
9	Include Flat Rock with an EFORd of 90% (240 MW)	3060	17.7 %
10	Include Flat Rock with an EFORd of 70% (240 MW)	3060	17.6 %
11	No Emergency Assistance from NE	3060	17.8 %
12	Remove all EDRPs	3060	17.7 %
13	Remove all SCRs[5]	3060	16.8 %
13a	Relocate all SCRs to Zones J and K	3060	16.6 %
14	Remove both EDRPs and SCRs	3060	17.5 %
15	IRM at an LOLE of 0.05 days/year (1/20)	3060	18.6 %
16	No voltage reductions	3060	19.2 %
17	IRM at an LOLE of 0.05 and no voltage reductions	3060	20.9 %

1 Installed Reserve Margin required to maintain NYSRC criterion of 0.1 days/year LOLE
2 Base Case model and assumptions are described in Appendix A.
3 Proposed Capacity is removed from NYC leaving the Capacity to Load ratio below 80%
4 Calculated outside of the MARS program.
5 The implementation and modeling of SCRs do not increase the probability of disconnecting load. See the Appendix A section on SCRs.

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 2.7 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 *
Base Case Assumptions (IRM = 17.1%)

Emergency Operating Procedure	Expected Implementation (Days/Year)
Require SCRs	4.4
Require EDRPs	3.1
5% manual voltage reduction	2.7
30 minute reserve to zero	2.6
5% remote control voltage reduction	1.7
Curtail Company use	1.2
Voluntary load curtailment	1.2
Public appeals	1.1
Emergency purchases	1.1
10 minute reserve to zero	0.5
Customer disconnections	0.1

* See Appendix A, Table A-2