# NEW YORK
# CONTROL AREA
# INSTALLED CAPACITY
# REQUIREMENT

*For The Period*
*May 2002 – April 2003*

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

***Executive Committee Resolution***
***And***
***Technical Study Report***

***December 14, 2001***

**NEW YORK STATE RELIABILITY COUNCIL, L.L.C.**
APPROVAL OF NEW YORK CONTROL AREA
INSTALLED CAPACITY REQUIREMENT FOR THE PERIOD
MAY 1, 2002 THROUGH APRIL 30, 2003

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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 14, 2001, conducted by the NYSRC Installed Capacity (ICAP) Working Group, show that the required NYCA installed reserve margin (IRM) for the May 1, 2002 through April 30, 2003 capability year is 18.0% under base case conditions; and

6. WHEREAS, in light of the Technical Study results, improved modeling and assumptions to more accurately 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, 2002 through April 30, 2003 capability year, which equates to an Installed Capacity Requirement of 1.18 times the forecasted NYCA 2002 peak load.

Adopted by the NYSRC Executive Committee on December 14, 2001.

# TECHNICAL STUDY REPORT

**December 14, 2001**
**New York State Reliability Council, L.L.C.**
**ICAP Working Group**

# TABLE OF CONTENTS



## APPENDIX A
## ICAP RELIABILITY MODEL AND ASSUMPTIONS



## APPENDIX B
## STUDY PROCEDURE, METHODOLOGY AND RESULTS

## INTRODUCTION

Section 3.03 of the New York State Reliability Council (NYSRC) Agreement states that the NYSRC shall establish the statewide annual 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 an engineering study conducted by the NYSRC for determining the appropriate NYCA required installed reserve margin (IRM) for the period May 2002 through April 2003 (year 2002) in compliance with the NYSRC Agreement. The ICR relates to the IRM through the following equation:

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

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 will also translate the required IRM to an "unforced capacity" basis, in accordance with a recent FERC filing. This concept is described later in the report.

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.

## EXECUTIVE SUMMARY

The technical NYSRC study described in this report shows that the required year 2002 statewide IRM requirement to be 18.0%[1] using base case assumptions. The study also showed that for various scenarios (some of them extreme) testing the required IRM sensitivity to changes in several key study assumptions, the required IRM would vary from 14.7% to 24.8%.

The study utilized improved inter-control area emergency assistance and resource capacity modeling representations to better simulate actual operating conditions. Further, the actual performance of the NYCA system during the 2001 summer peak period verified study assumptions regarding special case resources, emergency operating procedures (EOPs), and control area reserve sharing agreements. In addition, operating experience during the two years since formation of the NYISO and electric industry restructuring has given the NYSRC more confidence that the reliability model used for this study properly reflects NYCA system performance. The above factors have led to our conclusion that there is less uncertainty in this study's results than in the previous 2000 and 2001 IRM studies.

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[1] At the 99% confidence level, the IRMs calculated for this study have a bandwidth of ± 0.5%.

## STUDY PROCEDURE

This study used a probabilistic approach for determining required reserves. The technique commonly used in the electric power industry for such studies calculates the probabilities of outages of generating units, together with a model of daily peak-hour loads to determine the number of days per year of expected capacity shortages. The resulting measure, termed the "loss-of-load expectation" (LOLE) index, provides a consistent measure of generation system reliability. The acceptable LOLE in New York is stated in the NYSRC Reliability Rules. NYSRC Reliability Rule A-R1, Statewide Installed Reserve Margin Requirements, states:

> "Adequate resource capacity shall exist in the New York Control Area (NYCA) such that, after due allowance for scheduled outages and deratings, forced outages and deratings, assistance from neighboring systems, NYCA transmission 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 years."

This NYSRC Reliability Rule is consistent with NPCC Standards. The NPCC resource adequacy design criterion is as follows:

> "Each Area's resources will be planned in such a manner that, after due allowance for scheduled outages and deratings, forced outages and deratings, assistance over interconnections with neighboring Areas and regions, and capacity and/or load relief from available operating procedures, the probability of disconnecting non-interruptible customers due to resource deficiencies, on the average, will be no more than once in ten years."

The results of the study determine a required IRM; however, in day-to-day operations the actual available operating reserve may be more or less than this IRM.

The probabilistic analysis used a state-of-the-art computer model called the Multi-Area Reliability Simulation (MARS) Program. The MARS model is described in detail in Appendix A. This model includes a detailed load, generation, and transmission capacity representation of the NYCA, as well as the four external control areas interconnected to New York. Appendix A also addresses the key parameters and assumptions used in the study.

Appendix B provides details of the study results.

## STUDY RESULTS

The results of this study show that under the base case assumptions, the statewide required IRM is 18.0% for the year 2002. The MARS analysis using base case study assumptions is described in Appendix A. Maintaining a minimum installed reserve of 18.0% over the forecast NYCA 2002 summer peak would achieve applicable NYSRC and NPCC reliability criteria under these study assumptions. A description of the cases prepared for this study is shown in Appendix B, Table B-1.

The major parameters that affect NYCA IRM requirements are described below:

- *Interconnection Support During Emergencies.* The reliability of the NYCA is improved by receiving emergency assistance support from interconnected control areas, in accordance with control area reserve sharing agreements, during emergency conditions. This permits a required NYCA IRM that is 6.8 percentage points lower than otherwise required, under base case study assumptions (Table B-1, Case 1 – Case 2). These assumptions include external installed capacity (ICAP) purchases from Hydro-Quebec, ISO New England, and PJM (see "External ICAP" section below) that have the effect of reducing emergency assistance to the NYCA over direct ties from these control areas.

  The MARS model was enhanced in 2001 to better simulate reserve sharing agreements between NYCA and its interconnected control areas. Analysis using this more realistic reserve sharing representation to reflect actual operations, showed generally reduced emergency assistance available to NYCA compared to previous studies, which resulted in an increased IRM requirement of 1.6 percentage points (Table B-1, Case 1 - Case 20).

- *Load Forecast Uncertainty.* It is recognized that some uncertainty exists relative to forecast NYCA loads for any given year. This uncertainty was represented using a load forecast probability distribution (this probability distribution includes a range of loads from 27,800 MW to 32,430 MW) based on an analysis of the sensitivity of load levels to different weather conditions, as well as load forecasting error. The impact of representing this load forecast probability distribution in the base case, instead of a single point representation, results in a required IRM increase of 3.3 percentage points (Table B-1, Case 1 – Case 8).

- *Resource Capacity Availability.* IRM requirements are highly dependent on the availability of generating units and other types of resource capacity. A detailed analysis was performed to update the forced, partial, and scheduled maintenance representations of the NYCA generating units included in the model to reflect 1991-2000 availability performance.

  Also, in recognition that high ambient temperature and adverse water conditions have an impact on gas turbine and hydro capacity deratings, respectively, new models were developed to better represent the capacity of these types of resources under those abnormal conditions. These model improvements reduce capacity uncertainties that were noted in previous studies. Appendix A provides additional details on these models. Application of the new gas turbine and hydro models in this study increased IRM requirements by 1.4 percentage points (Table B-1, Case 1 – Case 19). In the 2001 IRM study, an adder of one percentage point was included in the base case IRM requirement of 17.1 percent to account for uncertainties related to resource capacity modeling. Because of the improved resource capacity modeling representation in this year's study, as described above, the need for this adder has been eliminated.

- *Locational Installed Capacity Requirements.* The MARS model used in this study provided an assessment of the adequacy of the NYCA transmission system to deliver energy from one zone to another for meeting load requirements. Previous studies found that, under the conditions assumed, there are transmission constraints into the New York City and Long Island zones that could impact the LOLE of these zones, as well as the statewide LOLE.

  To minimize these potential LOLE impacts, NYISO studies have shown that a minimum resource ICAP, i.e., locational ICAP, must be maintained in each of the New York City and Long Island zones. These locational ICAP requirements, recognized by NYSRC Reliability Rule A-R2 and monitored by the NYISO, supplement the statewide IRM requirement covered in this report. The most recent NYISO study (*Locational Installed Capacity Requirements Study,* dated February 14, 2001) determined that the LSEs serving the New York City and Long Island zones must maintain a minimum ICAP to load ratios of 0.80 and 0.98, respectively, for these zones. These minimum locational ICAP requirements were recognized in this NYSRC IRM study's base case representation.

  A planned New England to Long Island 330 MW HVDC tie, scheduled for 2002, is included as a sensitivity case in this year's study because of the uncertainty that its actual service date will meet the 2002 summer peak period. The sensitivity case indicated a 0.2 percentage point decrease in NYCA's required IRM as a result of the installation of the tie (Table B-1, Case 1 - Case18).

- *NYCA Installed Capacity Located in Neighboring Control Areas (External ICAP).* Locating a portion of the NYCA's required installed capacity in neighboring control areas without increasing interconnection capacity, has the effect of reducing the amount of interconnection support available during emergencies, thus increasing the required IRM. The base case assumed an expected NYCA external ICAP of 1672 MW, comprised of 1200 MW from HQ, 355 MW from ISO New England, and 117 MW from PJM. This is 581 MW less than was assumed in last year's study.

  The external ICAP transactions, as represented in this study, have the effect of increasing the required IRM by 1.6 percentage points (Table B-1, Case 1 - Case 3).

- *Special Case Resources.* Special case resources (SCRs) are energy limited ICAP resources that include loads that are capable of being interrupted and distributed generation that may be activated on demand. SCRs are used to supplement other NYCA ICAP resources for meeting peak loads during July and August. Because SCRs are energy limited, their reliability value is somewhat less than the same capacity of typical generation. The 2002 IRM study assumed that 515 MW of SCR capacity will be available during the 2002 summer period (see Appendix A).

The incremental amount of 361 MW of SCRs added to this year's study resulted in an increase in the required IRM of 1.0 percentage point (Table B-1, Case 1 - Case 22).

The appropriate IRM required for meeting reliability criteria depends on the study assumptions used in the analysis in addition to the many factors that influence the reliability of the system. Use of assumptions different than those used in the base case yields different required IRM outcomes. Figure 1 shows the sensitivity of required IRM results to several alternate assumptions. The sensitivity study results in this figure show a required IRM range of 14.7% to 24.8%.

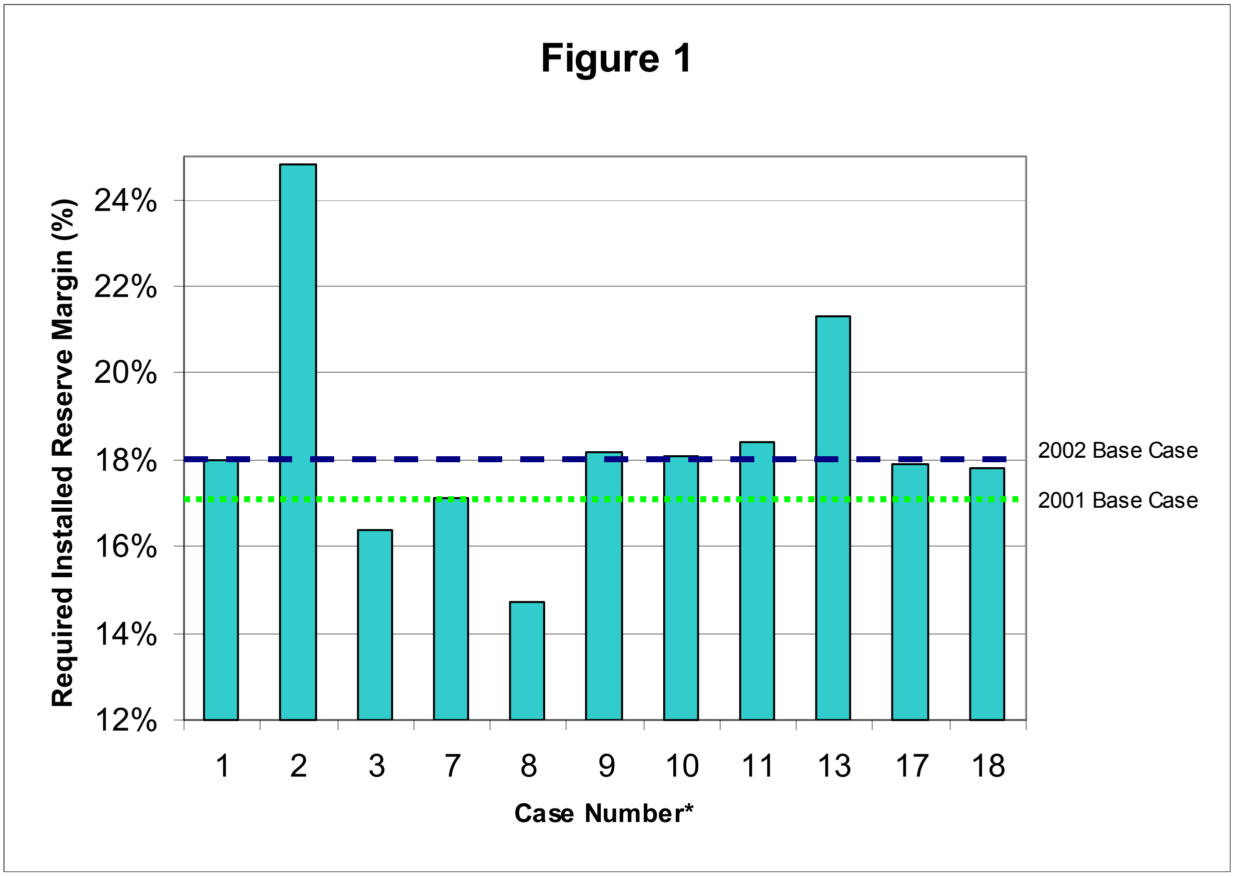
The NYISO will implement emergency operating procedures (EOPs) as required to minimize customer disconnections. The study indicates that if a 18.0% IRM is maintained under base case conditions, then on average, firm load disconnection due to inadequate resources will occur not more than once in every ten years in accordance with NYSRC and NPCC criteria (see Appendix B, Table B-2 for expected average use of voltage reductions and other EOPs).

## UNFORCED CAPACITY

The NYISO has filed tariff changes at FERC that will make fundamental changes to its capacity markets. In its July 2001 filing, the NYISO has proposed to value capacity sold and purchased in the market in a manner that considers the forced outage rates of individual units. This is referred to as "UCAP" which is intended to stand for "unforced capacity." In order to maintain consistency between the rating of a unit (UCAP) and the statewide reserve margin, the reserve margin must be translated to an unforced capacity basis. The conversion to UCAP is, essentially, a translation from one index to another and not a reduction of actual on-line resources, so no real degradation in reliability is foreseen. A difference in resource accounting may occur due to the different periods used for UCAP versus IRM transition rate calculations. Theoretically, the conversion to unforced capacity should provide financial incentives to decrease the forced outage rates, thus actually improving reliability.

## COMPARISON TO 2001 STUDY

The results of this study show a required statewide IRM, using base case assumptions, that is higher than that shown in the previous study, which was conducted for the 2001-2002 capability year. Table 1 shows a comparison of the required IRM impacts of key parameters associated with these two studies. The table shows that the primary factors increasing the IRM requirements are new gas turbine and hydro capacity derating models and reserve sharing modeling improvements, which are mostly offset by the updated scheduled maintenance representation. The net effect of these factors, along with the others listed in Table 1, is a required base case statewide IRM that is 0.9 percentage points higher than determined in the previous study.




* Refers to Appendix B, Table B-1

Sensitivities – changes from Base Case Assumptions:

| Case # | Description |
|---|---|
| 1 | Base Case |
| 2 | NYCA Isolated |
| 3 | No external ICAP |
| 7 | Grandfathered External ICAP Only |
| 8 | No Load Forecast Uncertainty |
| 9 | Without New Units (Units Installed during 2001) |
| 10 | Without planned units for 2002 |
| 11 | Reduce All Internal Transfer Limits by 10% |
| 13 | No Emergency Assistance from PJM |
| 17 | Additional 204 MW of combustion turbines on LI |
| 18 | Additional 330 MW HVDC tie from NE to LI |

**Table 1**

**COMPARISON WITH 2001 STUDY***

| Parameter | IRM % Change | IRM % |
|---|---|---|
| **Previous Study IRM (2001 Study)** | | **17.1** |
| MODEL IMPROVEMENTS IN 2002 STUDY*: | | |
| -- New gas turbine and hydro capacity derating models | + 1.4 | |
| -- Reserve sharing modeling enhancement | + 1.6 | |
| -- Remove generating capacity uncertainty IRM adder | - 1.0 | |
| -- Other modeling improvements | +0.3 | |
| | | |
| Net IRM Change from 2001 Study | + 2.3 | |
| **New Study IRM (2002 Study*) - Impact of Model Improvement Only** | | **19.4** |
| | | |
| UPDATED ASSUMPTIONS IN 2002 STUDY*: | | |
| -- Updated expected external ICAP representation | - 0.9 | |
| -- Updated forced outage rate representation | +1.1 | |
| -- Updated scheduled maintenance representation | -2.5 | |
| -- New generating units and other resource capacity | -0.2 | |
| -- Updated special case resource capacity | +1.0 | |
| -- Updated EOPs | -0.4 | |
| -- New load forecast | -0.3 | |
| -- Updated load forecast uncertainty representation | +0.7 | |
| -- Updated interconnected control area representation | +0.1 | |
| | | |
| Net IRM Change from 2001 Study | -1.4 | |
| **New Study IRM (2002 Study) - Impact of Model Improvements and Updated Assumptions** | | **18.0** |

*See report titled " New York Control Area Installed Capacity Requirements for the period May 2001 through April 2002", dated December 14, 2000, for 2001 study model description and assumptions.

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# APPENDIX A

# ICAP RELIABILITY MODEL
# AND
# ASSUMPTIONS

**MARS**
**Capacity Models - Units, FORs, Maintenance, Etc.**
**Load Models**
**Uncertainty Models: Load, FOR**
**Transmission Capacity Model**

## INTRODUCTION

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

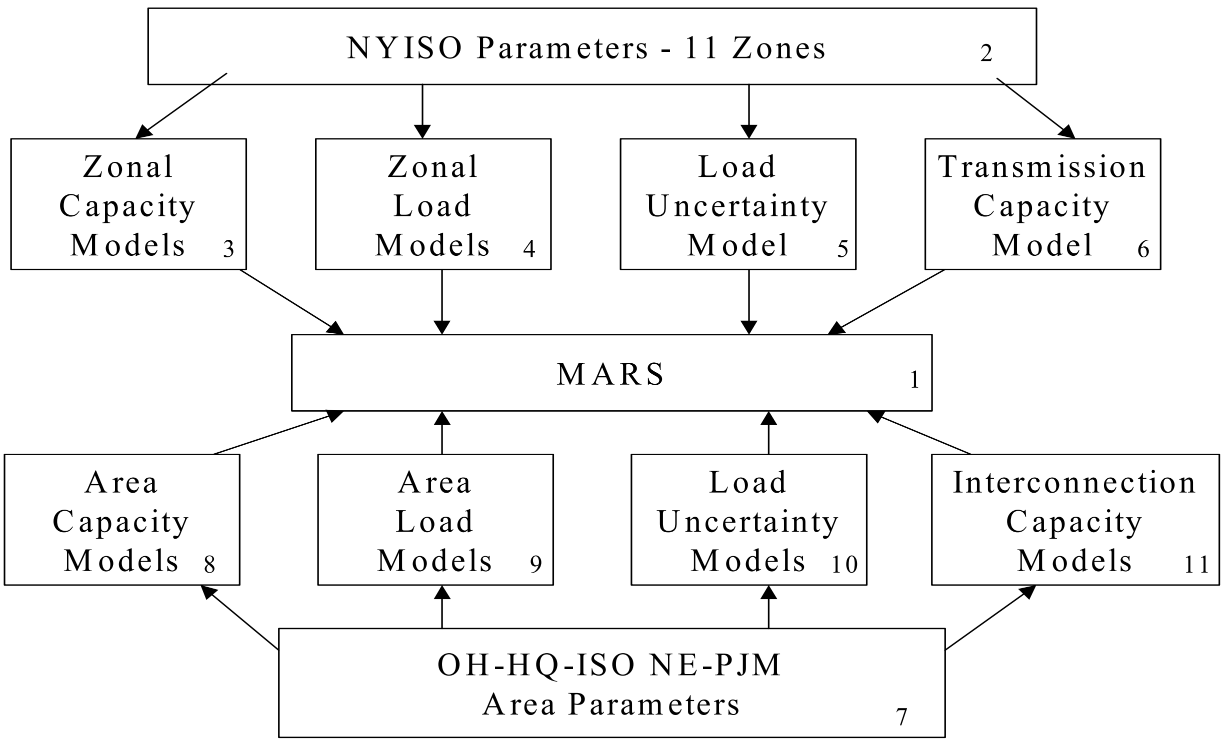
Table A-1 lists the study parameters in the Figure A-1 models, the source for the study assumptions, and where in Appendix A the assumptions are described. Figure A-1 depicts the computer program and related load, capacity and transmission models used for the study.

Finally, the last page of Appendix A compares the assumptions used in the 2001 and 2002 IRM reports.

# Table A-1
# Details on ICAP Modeling

| 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 16 |
| | | Generating Availability. | GADS Data | See page 18 |
| | | Unit Ratings. | 2001 Gold Book | |
| | Emergency Operating Procedures | Reduces load during emergency conditions to maintain operating reserves. | NYISO | See page 29 |
| 4 | Zone Load Models | Hourly loads | NYPP Historical load shape for 1995. | See page 25 |
| | | | NYISO peak forecasts. | 30,650 MW ISO Staff Forecast as of 8/20 |
| 5 | Load Uncertainty Model | Account for forecast errors due to weather and economic conditions. | Historical Data | See page 27 |
| 6 | Transmission Capacity Model | Emergency transfer limits of transmission interfaces between zones. | NYPP & NYISO transmission studies | See page 30 |
| 7 | IMO, HQ, ISO-NE, PJM control area Parameters | See the following items 8-11. | | |
| 8 | Control area Capacity Models | Generator Models in neighboring control areas | NPCC CP-8 study for NPCC Areas. MAAC Report and NERC Average outage rates for PJM | See page 33 |
| 9 | Control area Load Models | Hourly Loads | NPCC CP-8 study for NPCC Areas PJM Web site. | See page 25 |
| 10 | Load Uncertainty Models | Account for forecast errors due to weather and economic conditions | NPCC CP-8 Study | See page 27 |
| 11 | Interconnection Capacity Models | Emergency transfer limits of transmission interfaces between control areas. | NPCC CP-8 Study | See page 30 |

# Figure A-1
# NYCA ICAP Modeling



## MULTI-AREA RELIABILITY SIMULATION PROGRAM (MARS)

The General Electric Company's MARS program, which was jointly developed by General Electric and Associated Power Analysts as an Empire State Electric Energy Research Corporation (ESEERCO) project managed by New York Power Pool (NYPP) staff, enables the electric utility planner to quickly and accurately assess the ability of a power system, comprised of any number of interconnected areas, to adequately satisfy customer load requirements.

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, on an area and pool basis, the standard reliability indices of daily and hourly Loss of Load Expectation (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). To model the impact of emergency operating procedures, the program also calculates the expected number of days per year at specified positive and negative margin states.

In addition to calculating the expected values for the reliability indices, MARS (through a separate post-processor program) also produces probability distributions that show the actual yearly variations in reliability that the system could be expected to experience.

### Monte Carlo Simulation for Reliability Evaluations

In determining the reliability of a utility system, there are several types of randomly occurring events that must be taken into consideration. Among these are the forced outages of generating units, the forced outages of transmission capacity, and deviations from the forecasted loads. Monte Carlo simulation is a widely accepted technique for modeling the effects of such random events.

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, it cannot accurately model issues that involve time correlations, such as unit starting times or postponable unplanned 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 hour is dependent on its state in previous hours and influences its state in future hours. It thus requires the 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 historical 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 | 3 |
| 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 of each other state.

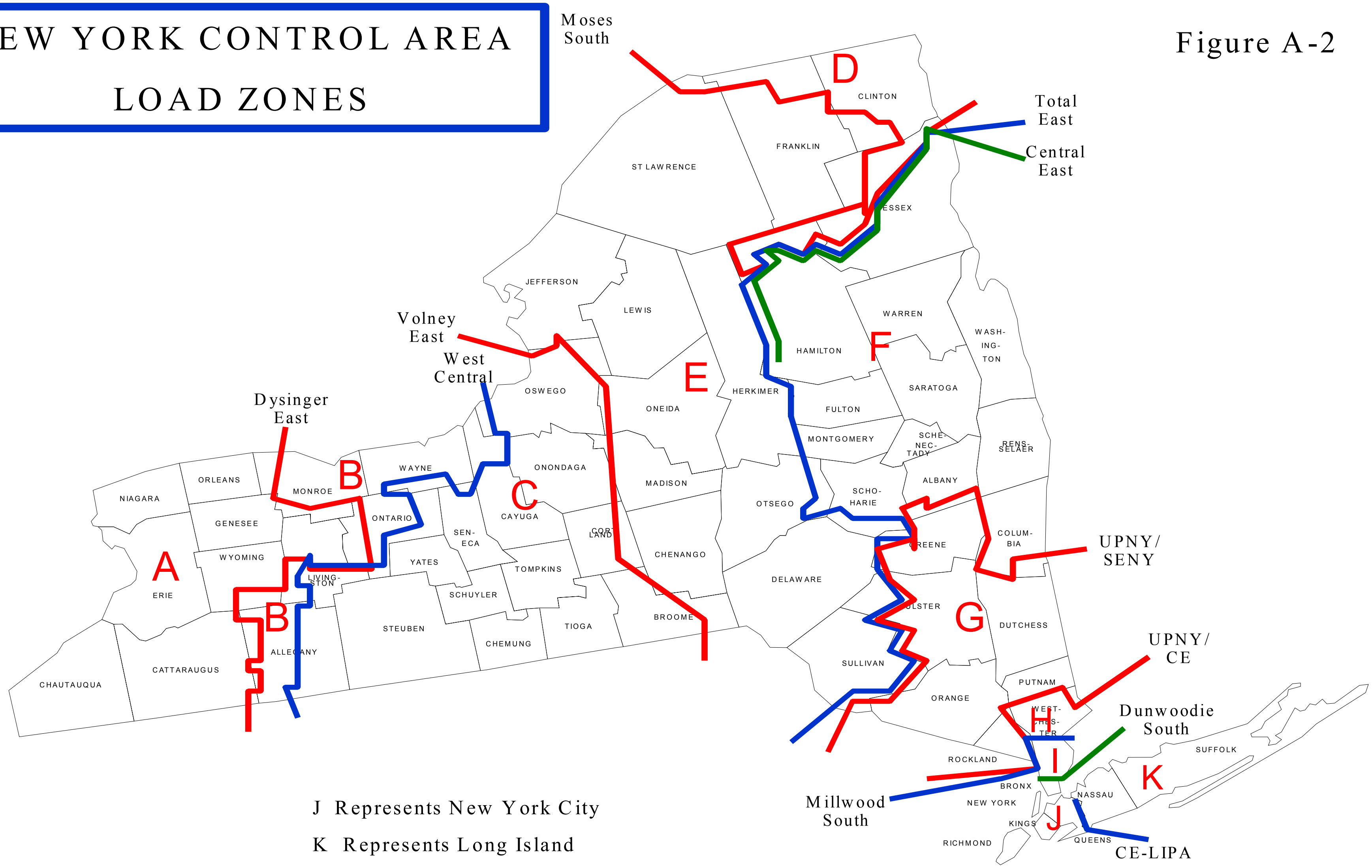
Whenever a unit changes capacity states, two random numbers are generated. The first is used to calculate the amount of time that the unit will spend in the current state; it is assumed that the time in a state is exponentially distributed, with a mean as computed from the transition rates. This time in state is added to the current simulation time to calculate when then 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 standard error places a confidence interval of ninety-five percent around the LOLE estimate. Twenty seven hundred and thirty (2,730) replications were simulated in the Base Case.

Figure A-2

# NEW YORK CONTROL AREA LOAD ZONES




J Represents New York City

K Represents Long Island

## NEW YORK CONTROL AREA

### CAPACITY MODELS

The capacity model includes unit ratings, full and partial forced outage representation, maintenance outages, Emergency Operating Procedures (EOPs) and firm transactions. For this study, all units located within NYCA, including those without capacity contracts, were included. These assumptions provided a total of 37,306 MW of capacity.

#### Existing and Planned Units

#### Ratings

The unit ratings were obtained from the NYISO "2001 Load & Capacity Data" (Gold Book). The following changes that were announced after the Gold Book was published are modeled in this study:

- **Retirements:**
  Jennison 1 and 2 and Hickling 1&2 for a total of -155 MW, Upstate
- **New Units: (Units installed during 2001)**
  Gowanus 5&6 79.9 – MW, NYC
  Binghamton Cogen - 40 MW, Zone C
  NYPA Brentwood - 47 MW, Long Island
  Harlem River 1 & 2 - 79.9 MW, NYC
  Hellgate 1&2 - 79.9 MW, NYC
  Hudson Ave. - 60 MW, NYC
  Kent GT 1 - 47 MW, NYC
  Pouch GT - 44 MW, NYC
  Vernon GT 2&3 79.9 MW, NYC
- **Planned Units for 2002:**
  SEF - 79.9 MW, NYC
  Fortistar 1&2 - 2 units at 79.9 MW each, NYC
  FP&L Far Rockaway - 44 MW, Long Island
  KeySpan Glenwood – 79.9 MW, Long Island
  Gotham – 79.9 MW, NYC
  PP&L Shoreham - 79.9 MW, Long Island
  JFK expansion - 45 MW, NYC
  East Coast Power Cogen upgrade - 15 MW, NYC

## Hydro Units

The Niagara and St. Lawrence hydroelectric projects are modeled with a probability capacity model that is based on historical water flows and unit performance. While energy production from the Niagara and St. Lawrence River projects is expected to be lower in 2002 due to below average water flows, the projects will still be able to achieve their maximum capacities in the event of a system emergency.

For other hydro facilities, a detailed analysis of annual hydro output variation was performed a number of years ago resulting in a hydro derate model for MARS. This analysis had set the hydro derating at approximately 25%. After an extreme derating of approximately 65% was observed during the summer 2001 period, it was decided that a derating of 45% would be appropriate.

## Special Case Resources and the Emergency Demand Response Program

Special Case Resources (SCRs) are loads capable of being interrupted on demand, and distributed generators, rated at 100 kW or higher, that are not visible to the NYISO's Market Information System. 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.

For this study, SCRs were modeled as energy limited resources capable of interrupting load for a maximum of twenty hours during the peak forecast months of July and August. The level of load modification was based on the summer 2001 experience of 515 MW.

## External Capacity From Contracts

There is 572 MW of grandfathered capacity modeled as firm purchases by NYCA, consisting of 400 MW from HQ, (summer only) 117 MW from PJM, and 55 MW summer and 90 MW winter from New England. There was also an additional firm winter purchase of 81 MW from Ontario Hydro. The Base Case assumes the following additional external ICAP: 800 MW (summer only) from HQ and 300 MW from New England. This totals 1,672 MW of expected external ICAP during the summer and 588 MW during the winter.

## Transactions

All firm sales are modeled as listed in the Gold Book for the year 2002.

## Generating Availability

## Forced and Partial Outages

The unit forced outage states for the majority of the large steam units was obtained from the ten year average NERC - Generating Availability Data System (GADS) outage data collected by NYPP and the NYISO for the years 1991 through 2000. 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 historical average forced outage rate data was appropriate. Figure A-3 provides a graph of Equivalent Forced Outage Rates under Demand (EFORd) over the 1991 through 2000 period. This means that the forced outage occurred at a time when the unit was required to operate. The graph presents unit aggregate averages for four zones with the NYCA and a NYCA total aggregate.

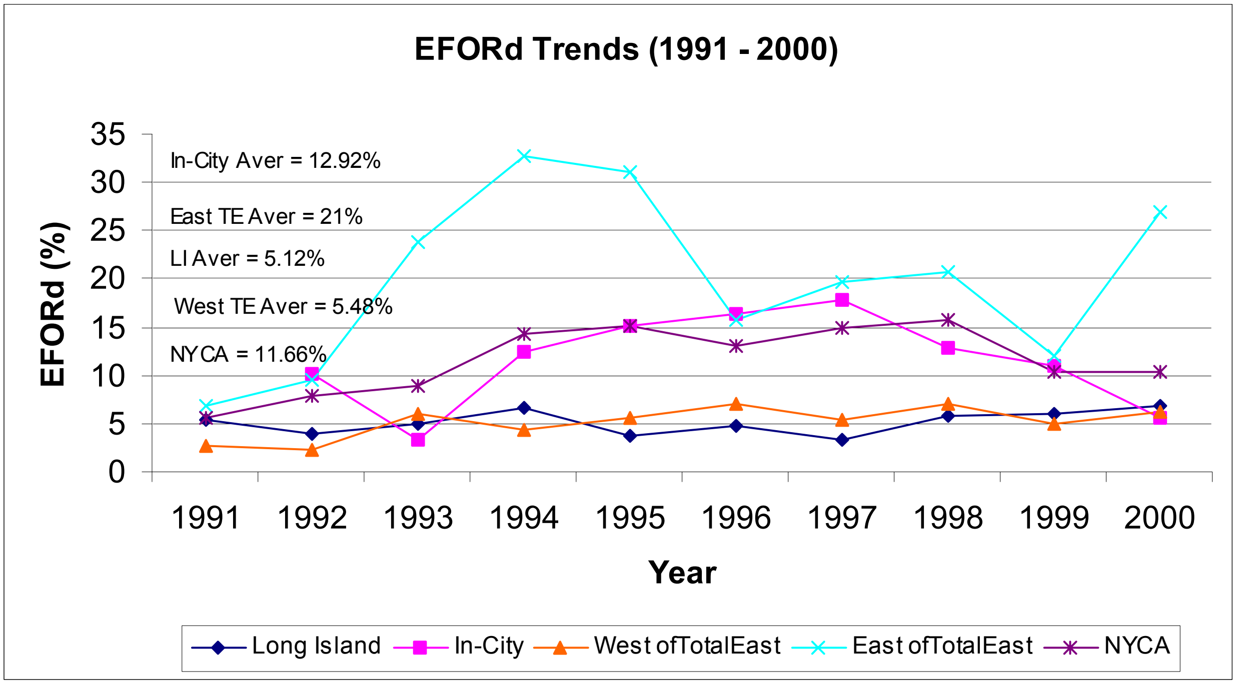
## Combustion Turbine Temperature Adjustments

A model of combustion turbine derating due to temperature in excess of DMNC test conditions was developed based on two parameters. The first parameter relates NYCA load to temperature and the second parameter relates combustion turbine derate 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.

An hourly derate model was developed that was active when the expected hourly load exceeded the normalized peak load forecast of 30,650 MW. Loads above this value would be simulated in the higher than forecast load uncertainty evaluation. The 80 MW per degree derate when weighted by the higher than expected peak load uncertainties and probabilities of occurrence produced an expected equivalent average derate of approximately 93 MW.

**Figure A-3**




## Scheduled Maintenance

The total amount of scheduled maintenance, which includes both planned and maintenance outages, was developed from a ten-year average of the same NERC-GADS data that was 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 historical outage time period. Figure A-4 provides a graph of scheduled outage trends over the 1991 through 2000 period for NYCA generators.

## Figure A-4

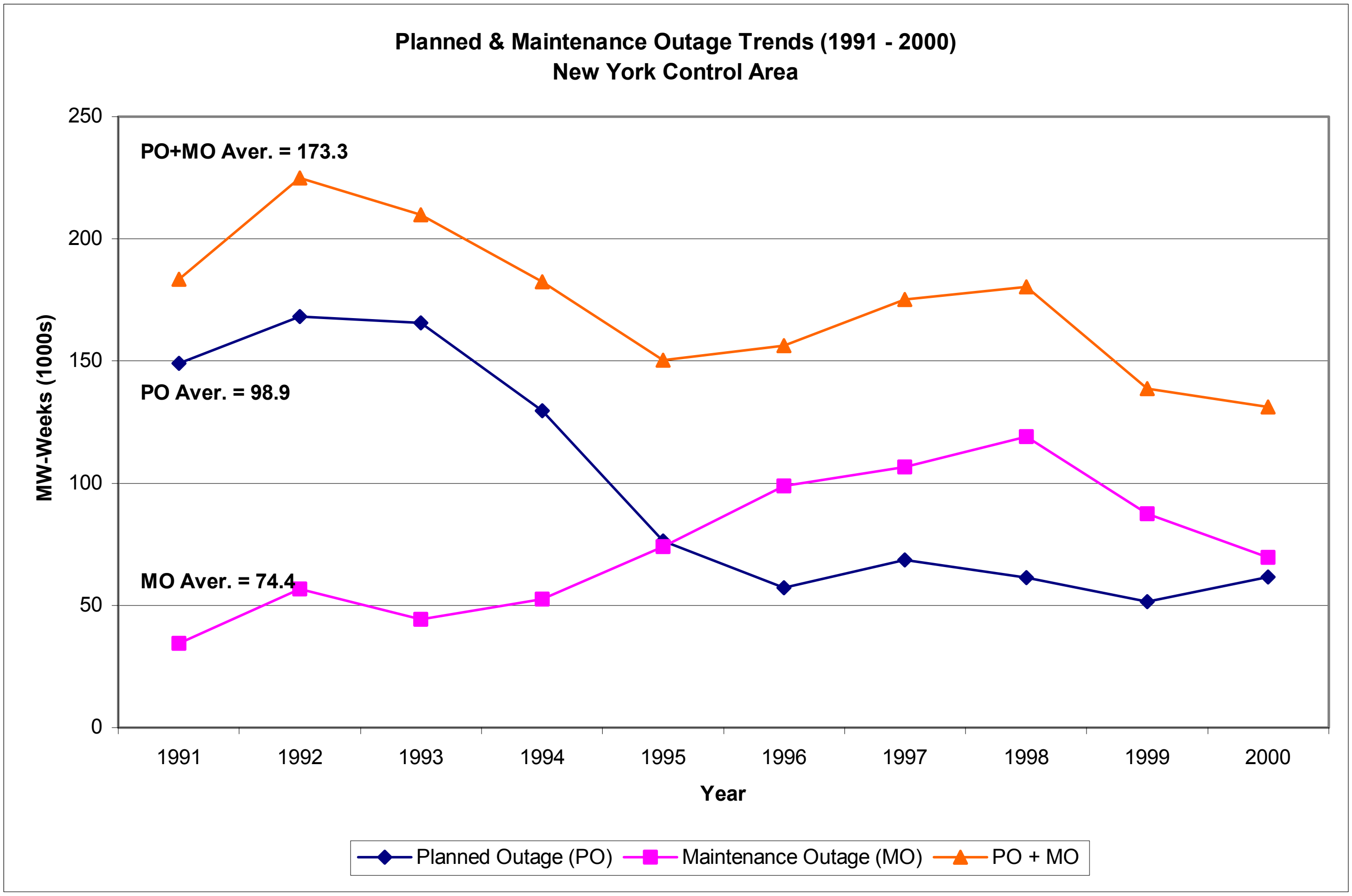
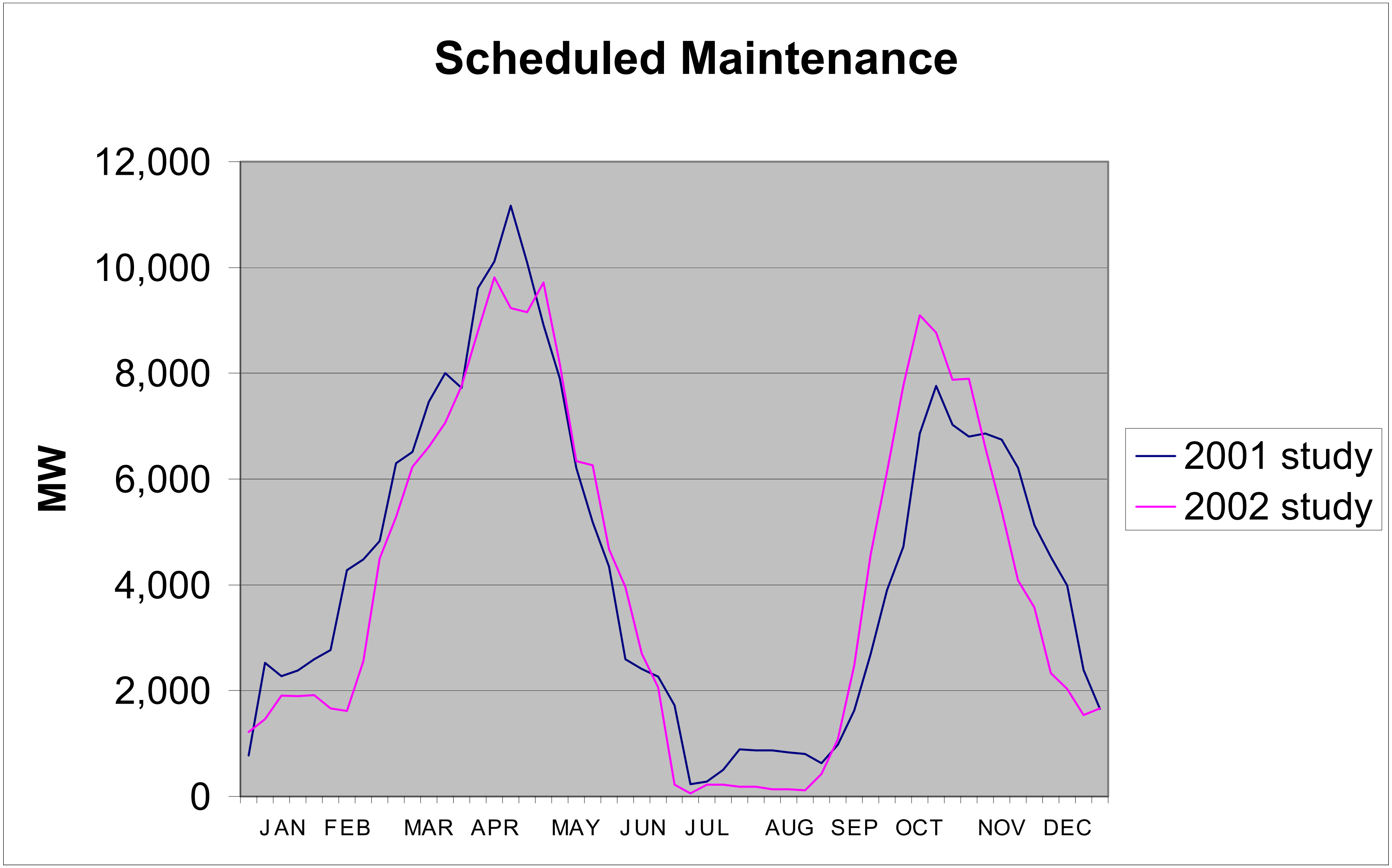



Figure A-5 shows the amount of capacity assumed to be on scheduled outages that was used in last year's study as well as that included in this year's study. The shift in maintenance out of the summer period has a significant impact on the results, but is consistent with the way scheduled outages are now being performed.

**Figure A-5**


Scheduled Maintenance
MW
12,000
10,000
8,000
6,000
4,000
2,000
0
JAN
FEB
MAR
APR
MAY
JUN
JUL
AUG
SEP
OCT
NOV
DEC
2001 study
2002 study

## 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.

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 2000 data from NERC is not available at this date.

Figure A-6

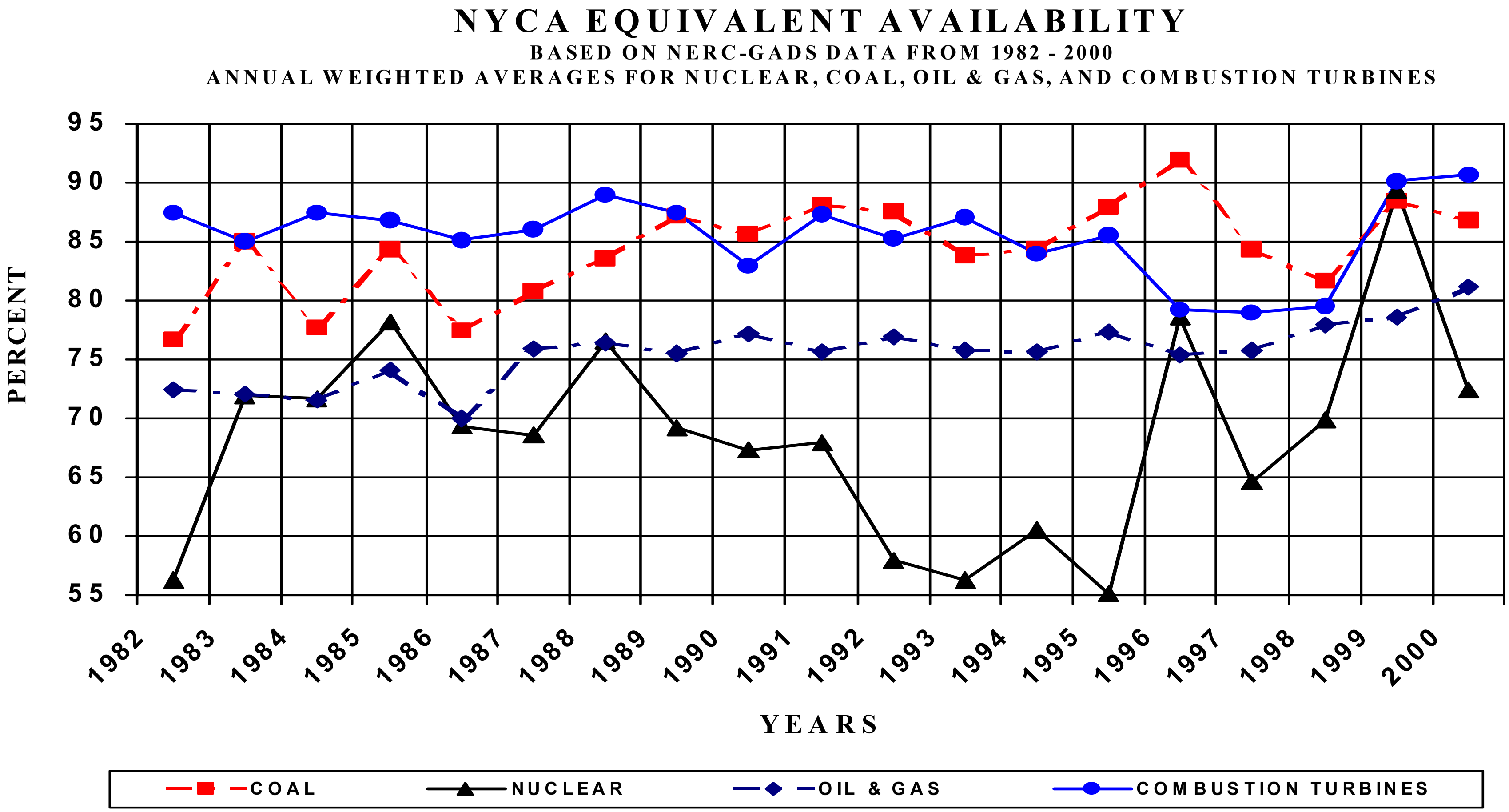
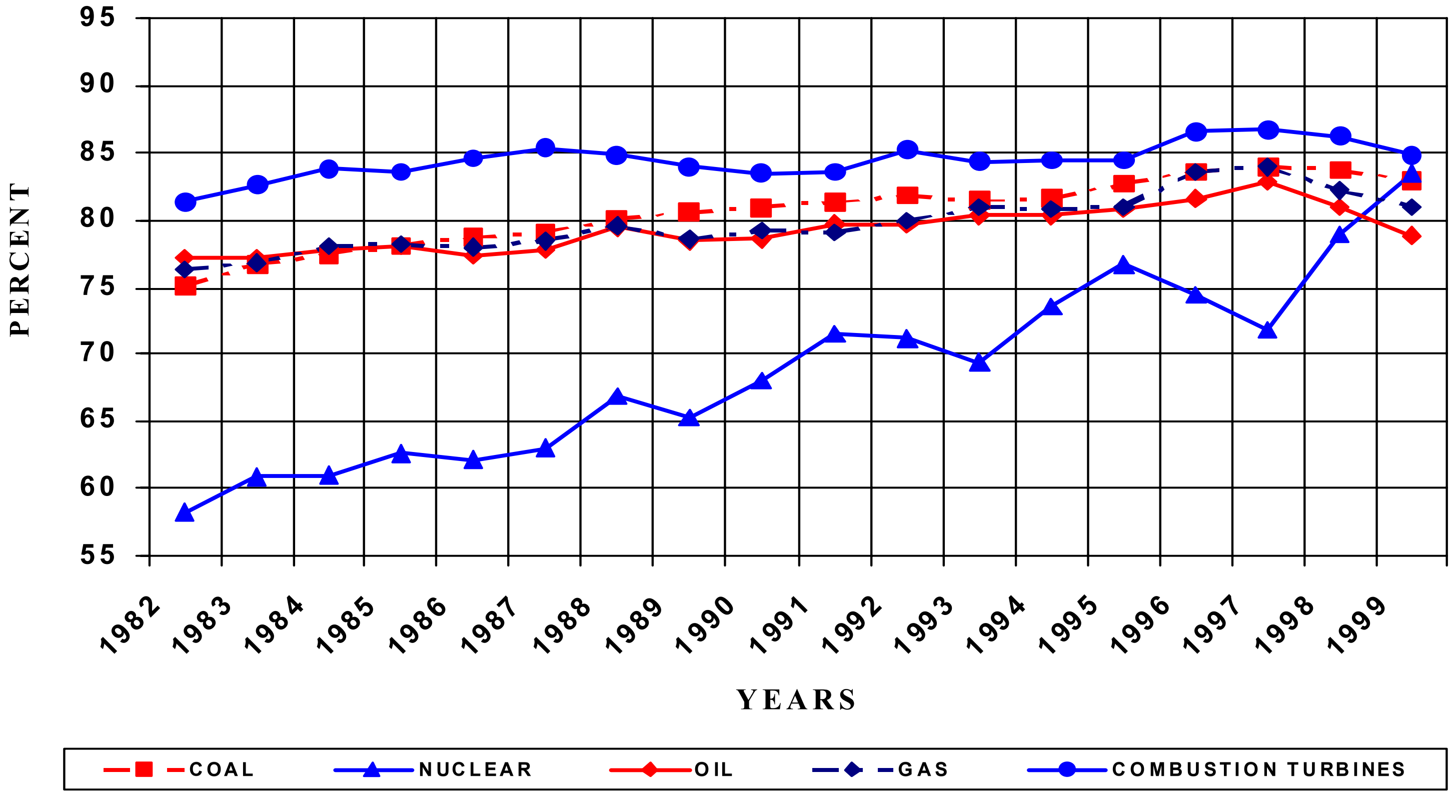

NYCA EQUIVALENT AVAILABILITY
BASED ON NERC-GADS DATA FROM 1982 - 2000
ANNUAL WEIGHTED AVERAGES FOR NUCLEAR, COAL, OIL & GAS, AND COMBUSTION TURBINES
PERCENT
95
90
85
80
75
70
65
60
55
1982
1983
1984
1985
1986
1987
1988
1989
1990
1991
1992
1993
1994
1995
1996
1997
1998
1999
2000
YEARS
COAL
NUCLEAR
OIL & GAS
COMBUSTION TURBINES

Figure A-7

# NERC EQUIVALENT AVAILABILITY

**BASED ON NERC-GADS DATA FROM 1982 - 1999**

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



## LOAD MODELS

An 8,760 chronological hourly model is input into the MARS program for each Control Area or zone modeled. The CP-8 study concluded that the historical year 1995 was a good load shape to use to represent the forecast year 2002. The 1995 load shape does not contain any extreme variations such as an extremely high peak that occurs for only a few hours, thus reducing exposure to potential LOLE events. The ICAP Working Group independently agreed to use the year 1995 load shape for this study.

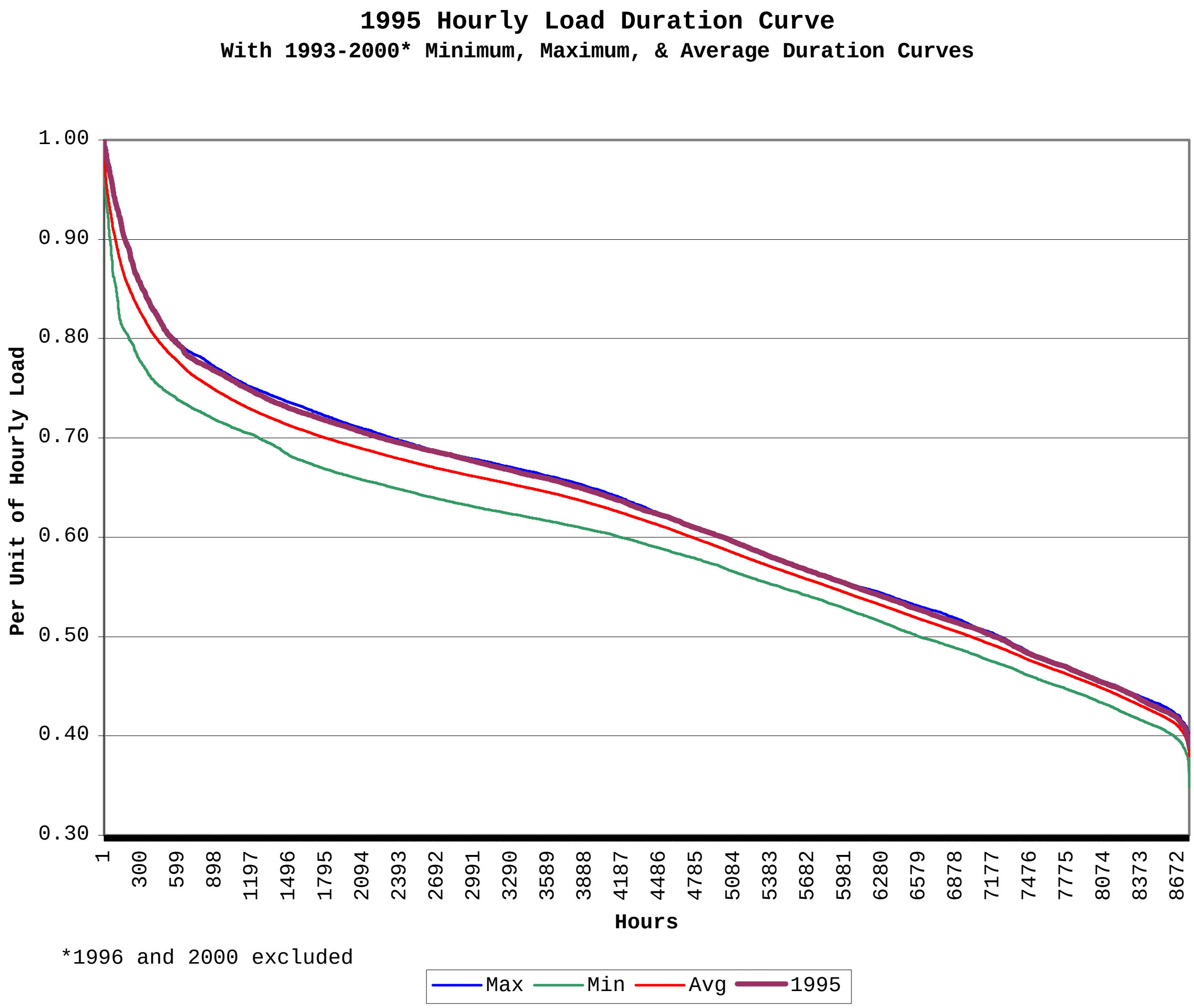
A measure of conservatism was added to the load model used in MARS by eliminating some peak load diversity. The 1995 loads were adjusted by moving each neighboring Control Area's loads in the calendar week in which that Control Area's peak load occurred to the calendar week of the NYCA peak. Also, each neighboring Control Area's loads in the calendar day in which that Control Area's peak load occurred were moved to the calendar day of the NYCA peak load. Even though Control Area peaks did not occur on the same day in 1995, different weather patterns could produce such an effect. Aligning Control Area peaks minimizes the amount of emergency assistance that may be available from neighboring Control Areas over system peak conditions.

Each Control Area's (the IMO, HQ, ISO-NE and NYISO) load forecast for the study year is based on its 1995 load shape, updated to reflect its most recent peak load and energy forecast. The NYCA forecast 2002 peak load used for this study is the most recent estimate of 31,100 MW by NYISO staff, which was reduced to 30,650 MW to reflect the moving of the Rockland Electric Load to the PJM Control Area.

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

The Figure A-8 shows maximum, minimum, and average load duration curves, as well as the 1995 load duration curve. Points on the maximum curve show the highest values for each ordered hour for the years 1993-1999 with the exception of 1996. In other words, for the second highest point, the value on the maximum curve is the highest of all the second points of each load duration curve for 1993-1999. Similarly for the minimum and average curves. The years 1996 and 2000 were evaluated and rejected because of the unusually cool summers and flat load duration curves. 1995 has the conservative property of having relatively many hours near the maximum curve in the highest ranked hours. The use of the 1995 load shape as the basis for the study's load shape model, because of this characteristic, provides a relatively higher annual LOLE than alternative load shapes.

# Figure A-8


1995 Hourly Load Duration Curve
With 1993-2000* Minimum, Maximum, & Average Duration Curves
Per Unit of Hourly Load
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
1
300
599
898
1197
1496
1795
2094
2393
2692
2991
3290
3589
3888
4187
4486
4785
5084
5383
5682
5981
6280
6579
6878
7177
7476
7775
8074
8373
8672
Hours
*1996 and 2000 excluded
Max
Min
Avg
1995

## Load Forecast Uncertainty

Load forecast uncertainty covers both the uncertainties of weather and load growth as they affect the load forecast. The intent of the study is to determine a near-term installed reserve margin for NYCA (i.e. 2002-2003); and, therefore, weather uncertainty is the dominant effect compared to load growth uncertainty. A NYCA peak load forecast for 2002 of 30,650 MW (provided by NYISO staff as of 8/20/01) was used to translate the per-unit distributions into the seven-state load distributions.

**Combined Uncertainty**: The probability distribution used in last year's IRM study combined an independent weather uncertainty distribution and load growth uncertainty distribution. The result of this process, applied to a 2002 peak load forecast of 30,650 MW is the following distribution for load uncertainty one-year ahead:

| Prob. % | Per Unit of Peak Load Forecast | Load (MW) |
|---|---|---|
| 0.62 | 0.921 | 28230 |
| 6.06 | 0.937 | 28720 |
| 24.17 | 0.965 | 29580 |
| 38.30 | 0.997 | 30560 |
| 24.17 | 1.022 | 31320 |
| 6.06 | 1.044 | 32000 |
| 0.62 | 1.056 | 32370 |

(See the New York State Reliability Council's report "New York Control Area Installed Capacity Requirements for the Period May 2001 Through April 2002" for the derivation of this distribution.)

**Supplemental 2002 Error Uncertainty Analysis:** An analysis of the actual error observed for one year-ahead forecast since 1979 indicates that this distribution may not exhibit enough variance. A one year-ahead error distribution was obtained by comparing the actual summer peak of a given year with the peak forecasted for that year in the previous years' Gold Books. The standard deviation of that distribution is approximately 1.17 %, while that of the combined uncertainty distribution above is only 1.01%. However, the errors are not entirely comparable because the process used to generate the one year-ahead forecast has changed. The methodology currently employed is that described in the NYISO Load Forecasting Manual. Previously, various methodologies have been used in the annual Gold Book. The current methodology should yield more accurate, and less variable, year-ahead forecasts because 1) it is produced nearer in time to the peak period being forecast (within six months vs. twelve to fifteen months lead time previously) and 2) the current methodology formally imposes a degree of consistency on forecast assumptions that was not present earlier. Although two years of experience is too little from which to draw quantitative conclusions, the weather-normalized error for the 2000 summer peak forecast was zero and for 2001, 0.3%. This supports the hypothesis that, in the new forecast environment, errors will be smaller.

With this experience in mind, an error distribution was developed which includes the one used for the 2001 IRM study and the empirical one referred to above. The result is shown in the table below:

| Prob. % | Per Unit of Peak Load Forecast | Load (MW) |
|---|---|---|
| 0.62 | 0.907 | 27800 |
| 6.06 | 0.946 | 28990 |
| 24.17 | 0.977 | 29950 |
| 38.30 | 1.000 | 30650 |
| 24.17 | 1.025 | 31420 |
| 6.06 | 1.050 | 32180 |
| 0.62 | 1.058 | 32430 |

The resultant standard deviation from this analysis is 1.07 %.

## 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 NYISO experience.

# Table A-2

**Emergency Operating Procedures**

| Step | Procedure | Effect | Percentage of Load | MW Value |
|---|---|---|---|---|
| 1 | Purchase | Increase capacity | N/A | Varies |
| 2 | Cancel firm sales | Load relief | N/A | 0 MW |
| 3 | 5% manual voltage Reduction | Load relief | 0.26 | 80 MW* |
| 4 | Thirty-minute reserve to zero | Allow operating reserve to decrease to largest unit capacity (10-minute reserve) | N/A | 600 MW |
| 5 | 5% remote voltage reduction | Load relief | 1.53 | 470 MW* |
| 6 | 8% remote voltage reduction | Load relief | 0.47 | 144 MW** |
| 7 | Curtail Company use | Load relief | N/A | 48 MW |
| 8 | Voluntary industrial curtailment | Load relief | N/A | 320 MW |
| 9 | General public appeals | Load relief | N/A | 138 MW |
| 10 | Ten-minute reserve to zero | Allow 10-minute reserve to decrease to zero | N/A | 1200 MW |
| 11 | Customer disconnections | Load relief | N/A | As needed |

**  These EOPs are modeled in the program as a percentage. The associated MW value is based on a forecast 2002 peak load of 30,650 MW.*
*** If the 8% remote voltage reduction were included the Con Edison system could expect an additional 144 MW of load reduction.*

The above values are based on the year 2001 actual results associated with a peak load forecast of 30,650 MW.-Exclusion of Step 6 in the study results in an additional measure of conservatism. 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 (excluding Step 6) presented in Table A-2 were modeled in the MARS program.

## TRANSMISSION CAPACITY MODEL

The NYCA is divided into 11 Zones. The boundaries between these zones and between adjacent control Areas are called interfaces. The maximum value of power that can flow across these interfaces is modeled. Different limits can be modeled in each direction. See Figure A-9.

The values are the emergency transfer limits and were provided by the CP-8 database for external interfaces and NYCA transmission studies for internal interfaces. The NYPP values were taken from a letter from the NYPP Transmission Planning Advisory Subcommittee to the NYPP Resource Planning Subcommittee dated May 10, 1996.

Updates to the above transfer limits through the year 2000 are documented below:

- The Dysinger-East and West Central limits were revised based on the 1997 NYPP Summer Operating Study.
- The IMO and ISO-NE limit revisions are based on those reported in the NYISO Summer 2000 Operating Study report.
- The Hydro Quebec limit is based on the NYISO decision to respect a 1500 MW voltage limit on the interface with HQ.
- The interface limit with PJM reflects the more conservative assumptions of the NYISO Summer 2000 Operating Study report about availability over the Con Edison PARS.
- The Norwalk Harbor tie limit was increased to reflect work performed at Northport by LIPA.
- The LIPA import limit was increased to reflect operating to STE post contingency ratings, which would occur prior to shedding load.

The following changes are updates from last year's IRM study:

- An increase of the transfer limit into Long Island of 330 MW is being run as a sensitivity to reflect the installation of a new cable to ISO New England.
- NYPA's FACTS Phase I project consisting of two (2) Statcoms at Marcy and a capacitor bank at Oakdale was assumed in-service. This increased the normal operating Central East transfer limit by 60 MW. The emergency Central East transfer limit was not increased due to other offsetting effects.
- This study also reduces the transfer limit into Long Island from 1590 MW to 1540 MW to reflect elimination of dynamic rating capabilities of the Y-50 cable.

In these reliability studies, the upstate transfer limits are not reached as they are in the day-to-day operation of the NYCA. This is because day-to-day operations use normal transfer limits and reliability studies use emergency transfer limits, which are generally higher.

In the reliability studies, the downstate combustion turbines are dispatched to avoid capacity shortages (instead of economic imports), emergency purchases are made from NE-ISO and PJM (which are not based on economics) and the transfer limits used are the emergency limits instead of the normal limits. These three factors combine to make the limits into New York City and Long Island the limiting factors in the study.

The downstate cable systems were modeled with forced outages. This is because when a cable does fail it takes weeks to repair. These forced outages are modeled as a distribution of MW reduction in transfer limit and a probability of occurrence. The starting point transfer limit for Dunwoodie-South is approximately the sum of the normal ratings on the 345 kV and 138 kV cables from the North. This starting point transfer limit is possible because of the phase angle regulator control and generator quick start capability within the Con Edison system.

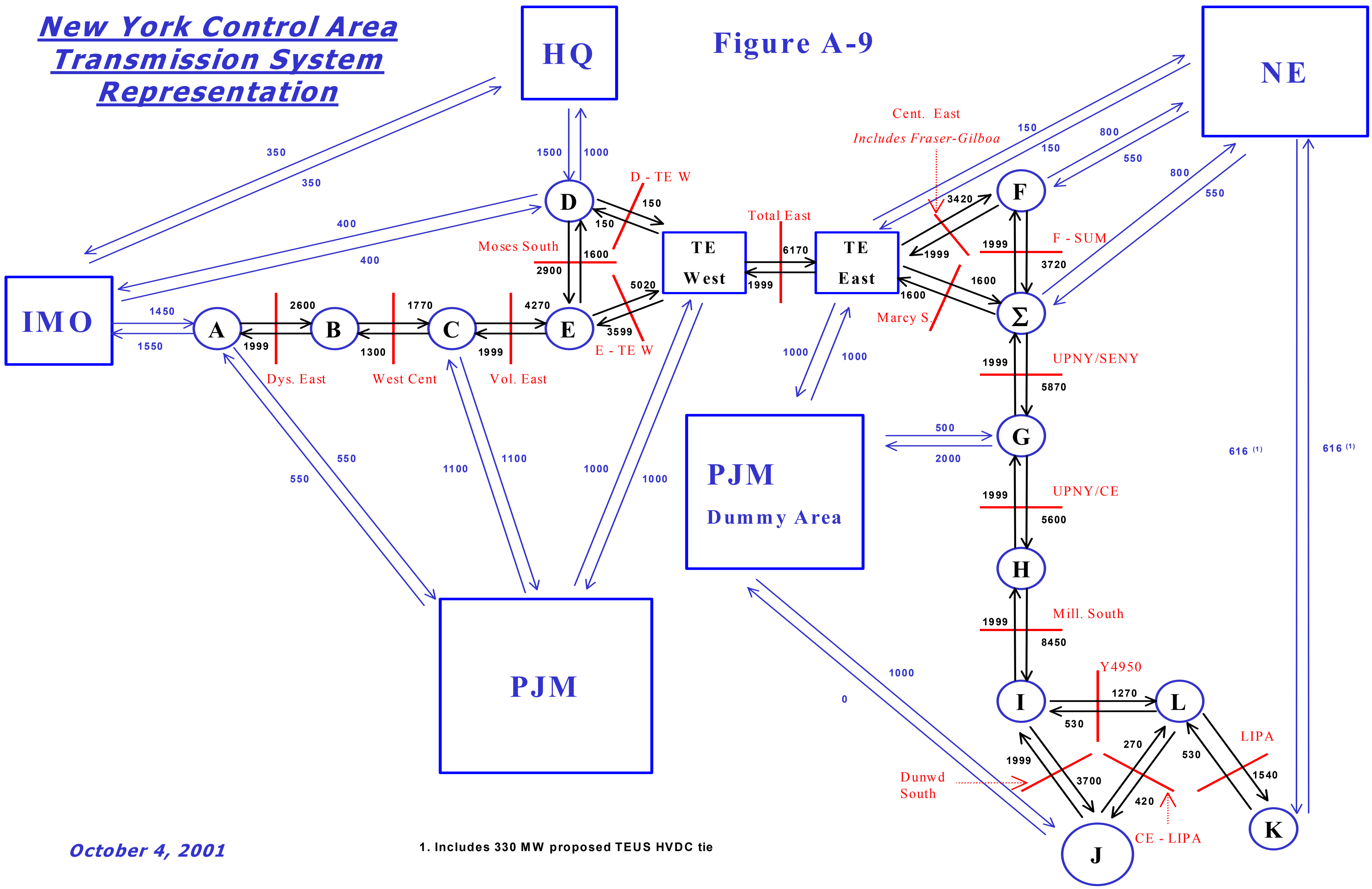
There are some explanations needed to clarify the above-mentioned diagram. All the power flows into New York City from PJM are set up to go through the Total East interface. The PJM Dummy area is set up to model the flows that can be allowed with the Con Edison/PJM phase shifters. While it is possible to have a flow of 3,500 MW into this dummy area, only 1,000 MW can reach area J through the two Hudson-Farragut and the Linden-Goethals phase shifters. This is based on the Con Ed – PSE&G contractual agreement.

The Σ area is also a dummy area that limits the total flow from upstate to downstate.

Area L is another dummy area that limits the flows between areas I, J and K.

# New York Control Area Transmission System Representation

Figure A-9




*October 4, 2001*

1. Includes 330 MW proposed TEUS HVDC tie

# NEIGHBORING CONTROL AREA REPRESENTATION

The NPCC members control area models are based on the models that they provided for the NPCC study "Summer 2001 Multi-Area Probabilistic Reliability Assessment" dated May 2001 (CP-8). The models for New England and Ontario Hydro have been updated. This study looked at the reliability models of the NPCC Control areas to be sure that the reliability of neighboring control areas was no better than that of the NYCA.

The representation of neighboring Control areas is done in a conservative manner to account for reserve sharing uncertainties. Installed reserve levels in neighboring control areas were assumed lower than required to meet their reliability criterion. This assumption lowers the emergency assistance to the NYCA from these control areas.

## Electric Supply and Demand Database

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 1995 load shape.

The EOPs were removed from the ISO-NE and IMO models (the only ones other then 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.

## ASSUMPTION SUMMARY

### COMPARISON OF ASSUMPTIONS USED IN THE 2001AND 2002 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 | 2001 REPORT | 2002 REPORT |
|---|---|---|
| NYCA Capacity | All Capacity in the NYCA | All Capacity in the NYCA |
| NYCA Unit Ratings | Based on 2000 Gold Book | Based on 2001 Gold Book |
| Planned Capacity | Updated to time of study | Current, See Page 15. A sensitivity case assumed 5 additional planned units on LI. |
| Unit Availability | NERC-GADS 1987-1996 | NERC-GADS 1991-2000 |
| Unit Maintenance Schedule | NERC-GADS 1987-1996 | Historical adjusted for forecasted time of year |
| Generating Capacity Uncertainty | +1.0% adder for temperature, environmental, etc. | None was used. |
| Neighboring Control areas – all except PJM | NPCC CP-8 Study | NPCC CP-8 Study |
| Neighboring Control area – PJM | Developed from public information | Used model developed for 2000 Report. |
| Load Model | 1995 NYCA shape | 1995 NYCA shape |
| Peak Load Forecast | 2000 Gold Book | ISO staff forecast of 30,650 MW (adjusted for loss of Rockland load.) |
| Load Model Uncertainty | Included weather and load growth uncertainty models | Includes updated load growth uncertainty model |
| External ICAP | Grandfathered plus 600 MW from HQ and 500 MW HQ to PJM | Grandfathered plus 300 MW from ISO-NE and 800 MW HQ |
| Emergency Operating Procedures | 934 MW load relief | 1056 MW load relief |
| Special Case Resources | 154 MW | 515 MW |
| Locational Capacity Requirements | Used results from 2000 NYSIO Locational Requirements Study | Used results from 2001 NYSIO Locational Requirements Study |
| Transfer Limits | Updated | Same as 2001 except for the reduction of LIPA import by 50 MW. A sensitivity case assumed the planned 330 MW tie to New England. |
| Inter-control Area reserve sharing priority | ---- | Updated |

# APPENDIX B

## DETAILS OF STUDY RESULTS

## 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.

## BASE CASE AND SENSITIVITY CASE RESULTS

Table B-1 summarizes the 2002 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) | NYCA Ext. Ties Rep.? | IRM * |
|---|---|---|---|---|
| **1** | **Base Case **** | **1672** | **Yes** | **18.0%** |
| 2 | NYCA Isolated | 0 | No | 24.8% |
| 3 | No External ICAP | 0 | Yes | 16.4% |
| 4 | 2001 Study Load Forecast Uncertainty | 1672 | Yes | 17.3% |
| 5 | 2001 Study EOPs | 1672 | Yes | 18.4% |
| 6 | 2001 Study Transfer Limits | 1672 | Yes | 18.0% |
| 7 | Grandfathered External ICAP Only | 572 | Yes | 17.1% |
| 8 | No Load Forecast Uncertainty | 1672 | Yes | 14.7% |
| 9 | Without New Units (Units Installed during 2001) | 1672 | Yes | 18.2% |
| 10 | Without planned units for 2002 | 1672 | Yes | 18.1% |
| 11 | Reduce All Internal Transfer Limits by 10% | 1672 | Yes | 18.4% |
| 12 | Test Locational Requirements | 1672 | Yes | 18.0% |
| 13 | No Emergency Assistance from PJM | 1672 | Yes | 21.3% |
| 14 | No Emergency Assistance from NE | 1672 | Yes | 18.4% |
| 15 | No Emergency Assistance from HQ | 1672 | Yes | 18.4% |
| 16 | No Emergency Assistance from IMO | 1672 | Yes | 18.4% |
| 17 | Include additional 204 MW of combustion turbines on LI | 1672 | Yes | 17.9% |
| 18 | Additional 330 MW HVDC tie from NE to LI | 1672 | Yes | 17.8% |
| 19 | Previous gas turbine and hydro capacity derating models | 1672 | Yes | 16.6% |
| 20 | Without reserve sharing modeling enhancement | 1672 | Yes | 16.4% |
| 21 | Hydro deratings to maximum observed 65% (667 MW) | 1672 | Yes | 18.6% |
| 22 | Without additional 361 MW (total 515) of Special Case Resources | 1672 | Yes | 17.0% |

* Installed reserve required to maintain NYSRC criterion of 0.1 days/year LOLE.
** Base Case model and assumptions are described in Appendix A.

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 two 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 = 18%)**

| Emergency Operating Procedure | Expected Implementation (Days/Year) |
|---|---|
| Emergency Purchases | 9.4 |
| 5% manual voltage reduction | 2.3 |
| 30 Minute reserve to zero | 2.2 |
| 5% remote control voltage reduction | 1.3 |
| Voluntary load curtailment | 0.4 |
| Public Appeals | 0.6 |
| 10 minute reserve to zero | 0.5 |
| Customer disconnections | 0.1 |

* See Appendix A, Table A-2