Northeast Power Coordinating Council
Multi-Area Probabilistic Reliability Assessment
For
Summer 2007

April 20, 2007

Conducted by the
CP-8 Working Group
The CP-8 Working Group acknowledges the efforts of Messrs. Glenn Haringa, GE Energy, Andrew Ford, the PJM Interconnection, and Paul Metsa, Hydro-Québec TransÉnergie, and thanks them for their assistance in this analysis.
FOREWORD

Use of operating procedures designed to mitigate resource shortages (specifically, reducing 30-minute reserve, voltage reduction, reducing 10-minute reserve, and public appeals) is not expected for the Northeast Power Coordinating Council, Inc. (NPCC) geographic areas (Areas) during the 2007 summer period under Base Case, expected load assumptions. The expected load level is the probability-weighted average of the seven load levels assumed. Recently added capacity in the NPCC Areas, in addition to the Demand Response Programs and transmission projects planned to be available this year are contributing factors that tend to reduce the need for the use of these operating procedures in 2007.

If reductions in anticipated resources, delay of expected transmission projects and/or additional transmission limitations into NPCC materialize coincident with higher than expected loads, New York and New England may experience conditions during the summer of 2007 that require the use of their operating procedures designed to mitigate resource shortages.
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EXECUTIVE SUMMARY

Introduction
This study assessed NPCC Area reliability for the year 2007 by estimating the annual Loss of Load Expectation (LOLE) and projected use of Area Operating Procedures designed to mitigate resource shortages for the summer of 2007 (May through September). The CP-8 Working Group closely coordinated its efforts with those of the CO-12 Working Group’s study, "NPCC Reliability Assessment for Summer 2007", April 2007.¹

General Electric’s (GE) Multi-Area Reliability Simulation (MARS) program was selected for the analysis. GE Energy was retained by the Working Group to conduct the simulations.

Results
All NPCC Areas demonstrated an annual LOLE of 0.1 days/year or less, under the Base Case assumptions for the expected load (the expected load is the weighted average of seven load levels, weighted by the probabilities assumed for each).

For the May - September 2007 period, Figure EX-1 shows the expected use of the indicated operating procedures under Base Case, expected load assumptions. The expected load level results were based on the probability-weighted average of the seven load levels simulated.

¹ See: http://www.npcc.org/seasonal.asp?Folder=CurrentYear
For the May - September 2007 period, Figure EX-2 shows the expected use of the indicated operating procedures under the Severe Case assumptions for the extreme load level (which represents the second to highest load level, having approximately a 6% chance of occurring).

Conclusions
As shown in Figure EX-1, use of the indicated operating procedures designed to mitigate resource shortages (specifically, reducing 30-minute reserve, voltage reduction, reducing 10-minute reserve, and public appeals) is not expected for the NPCC Areas during the 2007 summer period under the Base Case, expected load assumptions. The expected load level is the probability-weighted average of the seven load levels assumed. The expected usage of these operating procedures is significantly less than one occurrence. Recently added capacity in the NPCC Areas, in addition to the Demand Response Programs and transmission projects planned to be available this year are contributing factors that tend to reduce the need for the use of these operating procedures in 2007.

As shown in Figure EX-2, if reductions in anticipated resources, delay of expected transmission projects and/or additional transmission limitations into NPCC materialize coincident with higher than expected loads, New York and New England may experience conditions during the summer of 2007 that require the use of their operating procedures designed to mitigate resource shortages.
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Assuming higher than expected (having approximately a 6% chance of occurring) load and severe conditions (for example, the 660 MW Neptune Cable Project to Long Island NY not in-service, the New England to Long Island Cross Sound Cable available only for emergency transfers, demand-side programs impacts reduced by 50%, among other assumptions), the potential use of these operating procedures is more likely to be required in New York City and Long Island, NY, and, to a lesser extent, in Boston, MA, and southwestern CT.

INTRODUCTION

This study assessed the short-term reliability of Northeast Power Coordinating Council, Inc. (NPCC) for the year 2007 by estimating the annual Loss of Load Expectation and use of Area operating procedures to mitigate resource shortages for the summer (June through August) and shoulder (May and September) months. The Working Group closely coordinated its efforts with the CO-12 Working Group’s study, "NPCC Reliability Assessment for Summer 2006", April 2007.

The development of this Working Group was in response to recommendation (5) from the "June 1999 Heat Wave – NPCC Final Report", August 1999 that states:

“The NPCC Task Force on Coordination of Planning (TFCP) should explore the use of a multi-area reliability study tool as a part of an annual resource adequacy review to gain insight into the effects of maintenance schedules and transmission constraints on regional reliability.”

The database developed by the NPCC CP-8 Working Group's "NPCC Interregional Long Range Adequacy Overview", November 28, 2006, 2 was used as the starting point for this analysis. Working Group members reviewed the existing data and made revisions to reflect the conditions expected for the year 2007 assessment period.

This report is organized in the following manner: after a brief Introduction, specific Model Assumptions are presented, followed by an Analysis of the results based on the scenarios simulated. The Working Group's Objective and Scope of Work is shown in Appendix A. Tables presenting the corresponding results for the Base Case and Severe Case simulations are listed in Appendix B. Appendix C provides an overview of General Electric's Multi-Area Reliability Simulation (MARS) Program.

---

Load Representation
The loads for each Area were modeled on an hourly, chronological basis. The MARS program modified the input hourly loads through time to meet each Area's specified annual or monthly peaks and energies. Table 1 summarizes each Area's summer peak load assumptions for the year 2007. The values shown for Québec and the Maritimes Area show both their actual summer peak and the peak during the period of NPCC’s peak.

Table 1
Assumed NPCC 2007 Summer Peak Loads – MW

<table>
<thead>
<tr>
<th>Area</th>
<th>2002 Load Shape</th>
<th>Expected Peak</th>
<th>Extreme Peak</th>
<th>Month</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Québec (Q)</td>
<td></td>
<td>22,231</td>
<td>23,454</td>
<td>May</td>
</tr>
<tr>
<td></td>
<td></td>
<td>21,331</td>
<td>22,611</td>
<td>August</td>
</tr>
<tr>
<td>Maritimes Area 3</td>
<td>(MT)</td>
<td>3,915</td>
<td>4,307</td>
<td>May</td>
</tr>
<tr>
<td></td>
<td></td>
<td>3,624</td>
<td>3,986</td>
<td>July</td>
</tr>
<tr>
<td>New England (NE)</td>
<td></td>
<td>27,360</td>
<td>30,082</td>
<td>August</td>
</tr>
<tr>
<td>New York (NY)</td>
<td></td>
<td>33,447</td>
<td>35,822</td>
<td>August</td>
</tr>
<tr>
<td>Ontario (ON)</td>
<td></td>
<td>25,762</td>
<td>27,570</td>
<td>July</td>
</tr>
</tbody>
</table>

An explanation of each Area’s expected load forecast and methodology can be found in the companion NPCC CO-12 Working Group Report, “NPCC Reliability Assessment for Summer 2007”, April 2007.

NPCC Areas have different definitions for their extreme peak load forecasts. A brief summary of the basis of each NPCC Area's extreme peak load forecasts follows.

Québec
Québec doesn't forecast "extreme load" per se. Its reliability model includes a load forecast uncertainty which takes into account weather, economic, demographic and alternative heating fuels uncertainties.

Maritimes Area
The Maritimes Area doesn’t forecast “extreme load”; however, load forecast uncertainty is modeled in its reliability analysis. The load forecast uncertainty factors are developed by comparing the historical forecast values of load to the actual loads experienced.

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3 The Maritimes Area represents New Brunswick, Nova Scotia, Prince Edward Island, and the area administrated by the Northern Maine Independent System Administrator (NMISA).
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New England
The Independent System Operator of New England (ISO-NE) forecasts an extreme peak value having a 10% chance of being exceeded. ISO-NE assumes a weather condition that is defined by a three day weighted temperature-humidity index (WTHI) to forecast its summer peak load. The reference case value of the WTHI (80.1) is the 50th percentile of the portion of a WTHI distribution that encompasses the range of WTHI values at which the seasonal peak would occur. The extreme case value of the WTHI (82.0) is the 90th percentile of that distribution.

Although it is difficult to characterize a "normal" dry bulb temperature and the dew point temperature (because the three day weighting of the WTHI can be any number of combinations of temperature and humidity), a reasonable approximation would be 90 degrees F with a dew point of 70.

New York
The New York Independent System Operator (NYISO) bases its extreme load forecast on “one in 15 year” weather extreme for high temperature. The NYISO characterizes extreme weather conditions in terms of the NYISO summer index, which incorporates dry bulb and dew point values (temperature and humidity), as well as a build-up effect (through lagged elements in the equation).

Ontario
Ontario’s Independent Electricity System Operator (IESO) uses a multivariate econometric model to forecast energy and peak demand on the IESO controlled grid. Demand is defined as loads plus losses and peak demand refers to the highest hourly value.

The IESO does not directly provide a forecast of "extreme load" for this assessment. The IESO determines a value for load forecast uncertainty representing one standard deviation in demand, derived from the impact of temperature, humidity, cloud cover and wind speed on peak demand. The IESO expected demand and IESO load forecast uncertainty values were provided as input to this assessment.

Load Shape
In previous analyses, the Working Group has used two load shape assumptions for the analysis; the 1995 load shape 4 and the 2002 load shape. That selection was based on the review of the weather characteristics and corresponding loads for the years from 1988 through 2002. Based on comparison of the results from the previous analyses, and recent

weather experience, the Working Group concluded that the 2002 load shape was representative of a reasonable expected coincidence of Area load for summer 2007.

The growth rate in each month’s peak was used to escalate Area loads to match the Area's year 2007 demand and energy forecasts for both load shapes. The impacts of Demand-Side Management programs were included in each Area's load forecast. Figure 1(a) shows the diversity in the NPCC area load shapes used in this analysis for the 2002 load shape assumption.

![Figure 1(a) - 2007 Projected Monthly Expected Peak Loads for NPCC Areas 2002 Load Shape](image)

Figure 1(b) show the forecast daily summer peaks (June through August) modeled for the summer-peaking NPCC Areas (New England, New York, and Ontario) assuming the 2002 load shape. New England and New York closely track each other, while Ontario shows a similar pattern but with a bit more variation.
Load Forecast Uncertainty
Load forecast uncertainty was also modeled. The effects on reliability of uncertainties in the load forecast, due to weather and economic conditions, were captured through the load forecast uncertainty model in MARS. The program computes the reliability indices at each of the specified load levels (for this study, seven load levels were modeled) and calculates weighted-average values based on input probabilities of occurrence.

While the per unit variations in Area and sub Area load can vary on a monthly basis, Table 2 shows the values assumed for August, corresponding to the assumed occurrence of the NPCC system peak load (assuming the 2002 load shape). Table 2 also shows the probability of occurrence assumed for each of the seven load levels modeled.

In computing the reliability indices, all of the Areas were evaluated simultaneously at the corresponding load level, the assumption being that the factors giving rise to the
uncertainty affect all of the Areas at the same time. The amount of the effect can vary according to the variations in the load levels.

For this study, reliability measures are reported for two load conditions: expected and extreme. The values for the expected load conditions are derived from computing the reliability at each of the seven load levels, and computing a weighted-average expected value based on the specified probabilities of occurrence. The indices for the extreme load conditions provide a measure of the reliability in the event of higher than expected loads, and were computed for the second-to-highest load level. These values are shaded in Table 2.

### Table 2
**Per Unit Variation in Load Assumed for the Month of August 2007**

<table>
<thead>
<tr>
<th>Area</th>
<th>Per-Unit Variation in Load</th>
</tr>
</thead>
<tbody>
<tr>
<td>Q</td>
<td>1.0800 1.0600 1.0400 1.0000 0.9600 0.9450 0.9300</td>
</tr>
<tr>
<td>MT</td>
<td>1.1000 1.1000 1.0500 1.0000 0.9500 0.9000 0.9000</td>
</tr>
<tr>
<td>NE</td>
<td>1.2253 1.0995 1.0030 0.9289 0.9064 0.8792 0.8587</td>
</tr>
<tr>
<td>NY5</td>
<td>1.1049 1.0710 1.0283 0.9871 0.9411 0.8944 0.8582</td>
</tr>
<tr>
<td>ON</td>
<td>1.0706 1.0471 1.0235 1.0000 0.9765 0.9529 0.9294</td>
</tr>
<tr>
<td>Prob.</td>
<td>0.0062 0.0606 0.2417 0.3830 0.2417 0.0606 0.0062</td>
</tr>
</tbody>
</table>

### Generation
Tables 3 (a) and 3 (b) summarize the summer 2007 capacity assumptions for the NPCC Areas used in the analysis for the Base Case and the Severe Case Scenario, respectively. Also shown in Table 3 (a) is each Area’s annual weighted average unit availability percentage, based on each Area’s capacity according to the following relationship:

Annual Weighted Average Availability (%) = (1 - P.O.R.) x (1 - F.O.R.)

Where: P.O.R. = Total Hours on Planned Outage/Total Number of Hours
F.O.R. = Total Hours on Forced Outage/Total Number of Hours not on Planned Outage

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5 New York assumes different multipliers for Zone I, New York City (Zone J) and Long Island (Zone K). Values shown represent the weighted average value based on coincident zonal peak load.
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Table 3 (a)
NPCC Capacity and Load Assumptions for indicated Summer 2007 peak period - MW
Base Case - Expected Load

<table>
<thead>
<tr>
<th></th>
<th>Q (August)</th>
<th>MT (July)</th>
<th>NE (August)</th>
<th>NY (August)</th>
<th>ON (July)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Assumed Capacity</td>
<td>28,353</td>
<td>6,702</td>
<td>30,531</td>
<td>38,838</td>
<td>31,487</td>
</tr>
<tr>
<td>Net Purchase (+)/Sale (-)</td>
<td>2,658</td>
<td>-200</td>
<td>71</td>
<td>2,903</td>
<td>0</td>
</tr>
<tr>
<td>Peak Load³</td>
<td>21,331</td>
<td>3,624</td>
<td>27,360</td>
<td>33,447</td>
<td>25,762</td>
</tr>
<tr>
<td>Reserve (%)</td>
<td>45</td>
<td>79</td>
<td>12</td>
<td>25</td>
<td>22</td>
</tr>
<tr>
<td>Annual Weighted Average Unit Availability (%)</td>
<td>98.98</td>
<td>87.37</td>
<td>88.27</td>
<td>85.37⁹</td>
<td>80.31</td>
</tr>
<tr>
<td>Scheduled Maintenance ¹⁰</td>
<td>0</td>
<td>747</td>
<td>36</td>
<td>140</td>
<td>393</td>
</tr>
</tbody>
</table>

Table 3 (b)
NPCC Capacity and Load Assumptions for indicated Summer 2007 peak period - MW
Severe Assumptions Scenario - Extreme Load

<table>
<thead>
<tr>
<th></th>
<th>Q (August)</th>
<th>MT (July)</th>
<th>NE (August)</th>
<th>NY (August)</th>
<th>ON (July)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Assumed Capacity</td>
<td>28,353</td>
<td>6,702</td>
<td>30,531</td>
<td>38,607</td>
<td>30,585</td>
</tr>
<tr>
<td>Net Purchase (+)/Sale (-)</td>
<td>2,658</td>
<td>-200</td>
<td>401</td>
<td>1,913</td>
<td>0</td>
</tr>
<tr>
<td>Peak Load³</td>
<td>22,611</td>
<td>3,986</td>
<td>30,082</td>
<td>35,822</td>
<td>27,570</td>
</tr>
<tr>
<td>Reserve (%)</td>
<td>37</td>
<td>63</td>
<td>3</td>
<td>13</td>
<td>11</td>
</tr>
<tr>
<td>Scheduled Maintenance ¹⁰</td>
<td>0</td>
<td>747</td>
<td>36</td>
<td>1,118</td>
<td>503</td>
</tr>
</tbody>
</table>

Unit Availability

Details regarding the NPCC Area’s assumptions for generator unit availability are described in the respective Area’s most recent "NPCC Triennial Review of Resource Adequacy”,¹¹ updated for the 2007 summer period as described below.

6 Capacity shown for Québec adjusted for scheduled maintenance. Annual Weighted Average Unit Availability for Québec does not include scheduled maintenance.
7 Capacity shown for Ontario has been seasonally adjusted.
8 Based on the 2002 Load Shape assumption.
10 Maintenance shown is for the week of the monthly peak load.
Ontario’s generating unit availability was modeled as described in the IESO “18-Month Outlook: An Assessment of the Reliability of the Ontario Electricity System” (dated March 9, 2007).  

Ontario market participants provided the majority of generation data. F.O.R. and P.O.R. were based on forecast values for generating units, which reflect past experience and future expectations based on recent maintenance activities. However, for some of the generating units F.O.R. and P.O.R. values were based on North American Reliability Council (NERC) Generator Availability Data System (GADs) data for similar type units.

New England
This probabilistic assessment reflects New England generating unit availability assumptions based upon historical performance over the prior five-year period. Unit availability modeled reflects the projected scheduled maintenance and forced outages. Individual generating unit maintenance assumptions are based upon each unit’s historical five-year average of scheduled maintenance. Individual generating unit forced outage assumptions were based on the unit’s historical data and North American Reliability Council (NERC) average data for the same class of unit. A more detailed description of the modeling assumptions can be found at the ISO New England Web site.

New York

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11 See: [http://www.npcc.org/adequacy.cfm](http://www.npcc.org/adequacy.cfm)
14 These unit availability assumptions were used to develop New England Installed Capacity Requirements (ICR), which were filed with the Federal Energy Regulatory Commission on December 22, 2006. See: [http://www.iso-ne.com/regulatory/ferc/filings/2006/dec/er07-365-000.pdf](http://www.iso-ne.com/regulatory/ferc/filings/2006/dec/er07-365-000.pdf)
Transfer Limits
Figure 2 depicts the system that was represented in this Assessment, showing Area and assumed Base Case transfer limits for the year 2007. New York Area internal transmission representation was consistent with the assumptions used in the New York ISO February 16, 2007 Technical Study Report 16 - "Locational Installed Capacity Requirements Study covering the New York Control Area for the 2007 – 2008 Capability Year" and the “New York Control Area Installed Capacity Requirement for the Period May 2007 – April 2008” New York State Reliability Council, January 5, 2007 report. 17

New England internal transmission representation is consistent with the initial draft assumptions being developed through ISO-NE’s stakeholder process for their 2007 Regional System Plan. 18

Phase angle regulators (PARs) are installed on the Michigan - Ontario interconnection but are not available to regulate flows except in emergencies, pending agreement by the International Transmission Company in Michigan to permit full regulation.

The inability to regulate flows combined with limiting ratings on the PAR equipment can result in significant congestion of imports from Michigan. This was experienced in summer 2005. Before summer 2006, the IESO, the Midwest ISO, Hydro One and International Transmission Company, agreed to temporarily bypass the phase angle regulators for normal operation until an agreement is reached to make full use of their regulating capability. Bypassing the PARs increases Ontario’s transfer capability to and from Michigan by 300 to 350 MW in the summer and by about 400 MW in the winter.

Full regulating capability on the Michigan interface combined with increased import capability from the Niagara direction following completion of the Niagara expansion project, will provide a significant increase in the combined import capability from New York and Michigan. At this time, it is uncertain whether these improvements will occur within the period covered by this report.

The 230 kV interconnection line, B3N, between Scott TS in Ontario and Bunce Creek in Michigan was recently returned to service thus restoring the Michigan Ontario interconnection to its full capability under the current configuration with the PARs bypassed.

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Transfer limits between and within some Areas are indicated in Figure 2 with seasonal ratings (S- summer, W- winter) where appropriate. Details regarding the sub-Area representation for Ontario 12, New York 17, and New England 18 are provided in the respective references. The acronyms and notes used in Figure 2 are defined as follows:

Chur. - Churchill Falls
MANIT - Manitoba
ND - Nicolet-Des Cantons
BJ - Bay James
MAN - Manicouagan
NE - Northeast (Ontario)
MRO - Midwest Reliability Organization
NOR - Norwalk – Stamford
BHE - Bangor Hydro Electric
Mtl - Montréal
C MA - Central MA
W MA - Western MA
NBM - Millbank
Que - Québec Centre
NM - Northern Maine
NB - New Brunswick
PEI - Prince Edward Island
CT - Connecticut
NS - Nova Scotia
NW - Northwest (Ontario)
RFC - Reliability First Corp.
Operating Procedures to Mitigate Resource Shortages
Each NPCC Area takes defined steps as their reserve levels approach critical levels. These steps consist of those load control and generation supplements that can be implemented before firm load has to be disconnected. Load control measures could include disconnecting or reducing interruptible loads, making public appeals to reduce demand, and/or implementing voltage reductions. Other measures could include calling on generation available under emergency conditions, and/or reducing operating reserves.

The need for an Area to begin these operating procedures is modeled in MARS by evaluating the daily probabilistic expectation at specified margin states. The user specifies these margin states for each area in terms of the benefits realized from each emergency measure, which can be expressed in MW, as a per unit of the original or modified load, and as a per unit of the available capacity for the hour.

Table 4 summarizes the load relief assumptions modeled for each NPCC Area. The Working Group recognizes that Areas may invoke these actions in any order, depending on the situation faced at the time; however, it was agreed that modeling the actions as in the order indicated in Table 4 was a reasonable approximation for this analysis.

<table>
<thead>
<tr>
<th>Actions</th>
<th>Q</th>
<th>MT</th>
<th>NE</th>
<th>NY</th>
<th>ON</th>
</tr>
</thead>
<tbody>
<tr>
<td>1. Curtail Load / Utility Surplus</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>188</td>
</tr>
<tr>
<td>Appeals</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>1%</td>
</tr>
<tr>
<td>LRP/SCR/EDRP</td>
<td>0</td>
<td>0</td>
<td>616</td>
<td>1,220</td>
<td>0</td>
</tr>
<tr>
<td>Manual Voltage Reduction</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0.54 of load</td>
<td>0</td>
</tr>
<tr>
<td>2. No 30-min Reserves</td>
<td>500</td>
<td>233</td>
<td>578</td>
<td>600</td>
<td>473</td>
</tr>
<tr>
<td>3. Voltage Reduction or Interruptible Loads</td>
<td>0</td>
<td>566</td>
<td>1.86% of load</td>
<td>1.45% of load</td>
<td>2.60% of load</td>
</tr>
<tr>
<td>ELRP 21</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>159</td>
</tr>
<tr>
<td>4. No 10-min Reserves</td>
<td>750</td>
<td>625</td>
<td>1,000</td>
<td>0</td>
<td>895</td>
</tr>
<tr>
<td>General Public Appeals</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>264</td>
<td>0</td>
</tr>
<tr>
<td>5. EDRP</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>115</td>
</tr>
<tr>
<td>No 10-min Reserves</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>1,200</td>
<td>0</td>
</tr>
</tbody>
</table>

19 Derated value shown accounts for assumed availability.
20 Interruptible Loads for Maritimes Area (implemented only for the Area), Voltage Reduction for all others.
21 Emergency Load Reduction Program.
Assistance Priority

Table 5 indicates the priority order followed when allocating reserves and assistance to Control Areas with a resource deficiency. Areas listed with equal priority received assistance on a shared basis in proportion to their deficiency. In this analysis, each step was initiated simultaneously in all Areas and sub-Areas. It was assumed that PJM-RTO assists everyone with equal priority.

<table>
<thead>
<tr>
<th>Area Providing Assistance</th>
<th>Priority of Assistance</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>1&lt;sup&gt;ST&lt;/sup&gt;</td>
</tr>
<tr>
<td>Québec</td>
<td>MT ON NE NY</td>
</tr>
<tr>
<td>Maritimes Area</td>
<td>Q ON</td>
</tr>
<tr>
<td>New York</td>
<td>NE Q MT ON</td>
</tr>
<tr>
<td>New England</td>
<td>NY Q MT ON</td>
</tr>
<tr>
<td>Ontario</td>
<td>Q MT</td>
</tr>
<tr>
<td>Millbank Units</td>
<td>Q</td>
</tr>
<tr>
<td>PJM-RTO</td>
<td>NE NY</td>
</tr>
<tr>
<td>RFC-OTH</td>
<td>PJM-RTO</td>
</tr>
<tr>
<td>MRO-US</td>
<td>ON</td>
</tr>
</tbody>
</table>
Modeling of Neighboring Regions
For the scenarios studied, a detailed representation of the neighboring regions of RFC (ReliabilityFirst Corp.) and the MRO-US (Midwest Reliability Organization – US portion) was assumed. The assumptions are summarized in Table 6 and Figure 3.

<table>
<thead>
<tr>
<th></th>
<th>PJM-RTO</th>
<th>RFC-OTH</th>
<th>MRO-US</th>
</tr>
</thead>
<tbody>
<tr>
<td>Peak Load (MW)</td>
<td>137,235</td>
<td>109,618</td>
<td>34,112</td>
</tr>
<tr>
<td>Peak Month</td>
<td>July</td>
<td>August</td>
<td>July</td>
</tr>
<tr>
<td>Assumed Capacity (MW)</td>
<td>166,876</td>
<td>115,824</td>
<td>37,118</td>
</tr>
<tr>
<td>Reserve (%)</td>
<td>20</td>
<td>6</td>
<td>9</td>
</tr>
<tr>
<td>Weighted Unit Availability (%)</td>
<td>88.28</td>
<td>83.74</td>
<td>83.30</td>
</tr>
<tr>
<td>Operating Reserves</td>
<td>3,400</td>
<td>2,206</td>
<td>1,700</td>
</tr>
<tr>
<td>Voltage Reduction</td>
<td>1,673</td>
<td>2,000</td>
<td>1,666</td>
</tr>
<tr>
<td>No 30-min Reserves</td>
<td>2,100</td>
<td>1,470</td>
<td>1,200</td>
</tr>
<tr>
<td>Interruptible Load</td>
<td>2,201</td>
<td>0</td>
<td>1,100</td>
</tr>
<tr>
<td>No 10-min Reserves</td>
<td>1,300</td>
<td>736</td>
<td>500</td>
</tr>
<tr>
<td>Appeals</td>
<td>400</td>
<td>0</td>
<td>200</td>
</tr>
<tr>
<td>Load Forecast Uncertainty (%)</td>
<td>93.66 +/- 5.50, 11.00, 16.51</td>
<td>91.83 +/- 7.02, 14.04, 21.07</td>
<td>92.75 +/- 6.23, 12.47, 18.70</td>
</tr>
</tbody>
</table>

The diversity between the NPCC monthly peak loads and those of PJM-RTO, RFC-Other, and MRO-US are shown in Figure 3.

ReliabilityFirst is a newly formed not-for-profit company whose goal is to preserve and enhance electric service reliability and security for the interconnected electric systems within its territory. ReliabilityFirst was approved by the North American Electric Reliability Council (NERC) to become one of eight Regional Reliability Councils in North America and began operations on January 1, 2006.

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22 Load and capacity assumptions for RFC-Other based on NERC’s Electricity and Supply Database (ES&D) available at: [http://www.nerc.com/~esd/](http://www.nerc.com/~esd/)
ReliabilityFirst is the successor organization to three former NERC Regional Reliability Councils: the Mid-Atlantic Area Council (MAAC), the East Central Area Coordination (ECAR) Agreement, and the Mid-American Interconnected Network (MAIN) organizations. The year 2006 was a period of transition for the ECAR, MAAC and MAIN organizations, as their responsibilities were identified and transferred to ReliabilityFirst.

The RFC-Other area modeled in this analysis was intended to represent the non-PJM-RTO region data within RFC. The modeling of the RFC region is in transition due to changes in the regional boundaries between RFC, MRO, and SERC. This model was based on publicly available data from the 2005 NERC Electricity Supply & Demand (ES&D), which reported the data according to the old boundary definitions. The modeling of RFC-Other is expected to evolve for future studies as data reflecting the new regional boundaries becomes available. For now, the RFC-Other area is the non-PJM-RTO region that was formerly in either MAIN or ECAR. The MAIN and ECAR boundaries do not correctly define the new RFC boundaries, but this definition insures consistency within the use of the 2005 NERC ES&D data. The correct load and capacity for the non-PJM MAIN and ECAR region data are drawn out to model the reserves for this area.

Unit data was from the publicly available NERC data. From that data we represented each individual unit in the non-PJM RFC region, assigning each unit performance characteristics based on NERC class averages. The NERC class average characteristics
were obtained from the 2005 update of NERC pc-GAR application, using the latest five year period of 2000-2004 for the determination of the class average data.

**MRO**
The Midwest Reliability Organization (MRO) is a non-profit organization dedicated to ensuring the reliability of the bulk power system in the North Central part of North America. The primary focus of the MRO is ensuring compliance with regional and international reliability standards and criteria utilizing open, fair processes in the public interest.

Formation of the MRO was approved by the Mid-Continent Area Power Pool (MAPP) Executive Committee in November 2002. In 2005, this organization became operational and replaced the MAPP Regional Reliability Council of the North American Electric Reliability Council.

The U.S. portion of the MRO was modeled in this study, recognizing the strong transmission ties to the rest of the study system. This allowed a straightforward approach to develop the load and capacity data public sources such as the 2005 NERC ES&D data. From that data we represented each individual unit in the MRO-US area, assigning each unit performance characteristics based on NERC class averages. The NERC class average characteristics were obtained from the 2005 update of NERC pc-GAR application, using the latest five year period of 2000-2004 for determining of the class average data.

The MRO-US boundary definition was based on the NERC data which still included the MAIN region. Going forward, the NERC data boundaries will change due to the new RFC region and the corresponding boundary changes between RFC, MRO and SERC. For this model, the previous MRO, MAIN, ECAR and SERC boundaries applied with this expected to evolve for future studies as more current data becomes available.

**PJM-RTO**

**Load Model**
The load model used for the PJM-RTO corresponds to the PJM Planning division's technical methods to produce a load model of the 2007 forecast year. The hourly load shape is based on observed 2002 calendar year values, which reflects representative weather and economic conditions for a peak planning study. The hourly loads were then adjusted per the PJM Load Forecast Report, February 2006, for the forecast monthly loads. This study modeled load forecast uncertainty consistent with that used in recent probabilistic PJM models, per the above references, which reflects uncertainty for loads at a predetermined probability of occurrence. This load uncertainty typically reflects

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factors such as weather, economics, diversity (timing) of peak periods among internal
PJM zones or regions, the period years the model is based on, sampling size, and how
many years ahead in the future the load forecast.

**Expected Resources**
The generation resources correspond to the publicly available EIA-411 data, submitted on
or before April 1, 2006. Existing generation resources, planned additions, modifications,
and retirements are per the EIA-411 data submission and the PJM planning process.
Active Load Management (ALM) is reflected in this model's Emergency Operating
Procedure level 1, corresponding to the publicly available data on the PJM web site
modeling of Active Load Management corresponds to the PJM Operations Staff ability to
call up to 10 ALM events, in a peak period.

**Expected Transmission Projects**
The transfer values shown in the study are reflective of peak load flow model conditions.
PJM is a summer peaking area. The studies performed to determine these transfer values
are in line with the Regional Transmission Planning Process employed at PJM, of which
the Transmission Expansion Advisory Committee (TEAC) reviews these activities. All
activities of the TEAC can be found at the pjm.com web site. All transmission projects
are treated in aggregate, with the appropriate timing and transfer values changing in the
model, per the TEAC information available on the PJM web site. ²⁴

²⁴ See: http://www.pjm.com/committees/teac/teac.html
Summer 2006 Review
NPCC and neighboring Regions experienced sustained widespread, hot and humid conditions during the summer of 2006. New York, Ontario, New England and neighboring Areas’ summer peak demands (as compared against 2005 forecast assumptions in Table 7) exceeded their existing all-time peak demand.

Ontario Summary
Ontario set a new all-time record for electricity demand of 27,005 MW at 5:00 p.m., August 1st, exceeding the previous record of 26,160 MW set on July 13, 2005.

Due to high temperatures and high humidity levels, the IESO issued Power Warnings asking for consumers to reduce their use of electricity throughout the day on August 1st and 2nd. By comparison, the IESO issued 12 Power Warnings last year.

There were no activations of the ELRP or EDRP load reduction programs, and no voltage reductions for overall resource adequacy purposes.

There were 5% voltage reductions made on Monday, July 31, 2006 in the East and Ottawa zones due to the Adirondack – ONT flowgate exceeding the post contingency thermal limits.

Due to transmission circuit limit concerns, the IESO made emergency energy purchases from its neighbouring interconnections of 97 MWh on Friday, July 28, 2006 in hour 17, and 461 MWh on Monday, July 31, 2006 in hours 15 to 20.

At the time of the Aug 1st peak, economic exports of 5 MW were scheduled and economic imports of 1776 MW were scheduled.

New York Summary
A sustained heat wave resulted in a record demand for electricity in New York between 4:00 and 5:00 p.m. on Tuesday, August 1st; the NYISO recorded an hourly average peak load of 33,879 MW, surpassing a record 32,624 MW set on July 17th. New York then reached 33,939 MW on August 2nd, beating the August 1st record by 60 MW.

To avert a possible power reserve shortage in New York City and Long Island, the NYISO called on companies in its special case Resources (SCR) and emergency Demand response Program (EDRP) to curtail usage from 2:00 to 7:00 p.m. on August 1st. Additional calls occurred on August 2nd and 3rd in Upstate NY zones.

New England Summary
New England set a new record for electricity consumption August 2nd. The regional electricity use reached 28,127 MW at hour ending 3:00 p.m., surpassing the record of 27,401 MW, set August 1st. The previous record, 27,395 MW, was set on July 18, 2006.
The extreme temperature and humidity combined to drive electricity use to record levels. On August 1\textsuperscript{st} and 2\textsuperscript{nd}, ISO-NE implemented operating procedures to keep pace with this record consumption, including asking consumers across New England to conserve electricity, requesting large commercial users to interrupt usage through demand response programs, and bringing in emergency resources from neighboring systems.

OP-4 Action 6 (reduce 30-min reserve) was called on August 1\textsuperscript{st} and 2\textsuperscript{nd}. OP-4 Action 12 (voltage reduction) was called on August 2\textsuperscript{nd}. No OP-4 Actions were called on July 18\textsuperscript{th}.

### Table 7
NPCC 2006 Summer Peak Loads Actual versus Forecast – MW

<table>
<thead>
<tr>
<th>Area</th>
<th>Actual Peak</th>
<th>Date</th>
<th>Expected Peak</th>
<th>Extreme Peak</th>
<th>Shape</th>
<th>Expected Peak</th>
<th>Extreme Peak</th>
<th>Shape</th>
</tr>
</thead>
<tbody>
<tr>
<td>Québec</td>
<td>21,873</td>
<td>May 2</td>
<td>22,558</td>
<td>23,571</td>
<td>May</td>
<td>22,558</td>
<td>23,571</td>
<td>May</td>
</tr>
<tr>
<td></td>
<td>21,401</td>
<td>June 19</td>
<td>21,655</td>
<td>22,629</td>
<td>August</td>
<td>21,655</td>
<td>22,629</td>
<td>August</td>
</tr>
<tr>
<td></td>
<td>21,257</td>
<td>July 14</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>21,369</td>
<td>August 1</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Maritimes Area</td>
<td>3,385</td>
<td>May 3</td>
<td>4,018</td>
<td>4,420</td>
<td>July/August</td>
<td>4,088</td>
<td>4,497</td>
<td>May/August</td>
</tr>
<tr>
<td></td>
<td>3,286</td>
<td>June 29</td>
<td>3,626</td>
<td>4,000</td>
<td></td>
<td>3,676</td>
<td>4,044</td>
<td></td>
</tr>
<tr>
<td></td>
<td>3,356</td>
<td>July 17</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>3,309</td>
<td>August 21</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>New England</td>
<td>27,395</td>
<td>July 18</td>
<td>27,025</td>
<td>29,725</td>
<td>July</td>
<td>26,067</td>
<td>28,671</td>
<td>July</td>
</tr>
<tr>
<td></td>
<td>27,401</td>
<td>August 1</td>
<td>25,927</td>
<td>28,517</td>
<td>August</td>
<td>27,025</td>
<td>29,724</td>
<td>August</td>
</tr>
<tr>
<td></td>
<td>28,127</td>
<td>August 2</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>27,025</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>New York</td>
<td>32,624</td>
<td>July 17</td>
<td>32,424</td>
<td>34,042</td>
<td>July</td>
<td>32,793</td>
<td>34,429</td>
<td>July</td>
</tr>
<tr>
<td></td>
<td>33,879</td>
<td>August 1</td>
<td>33,295</td>
<td>34,956</td>
<td>August</td>
<td>33,295</td>
<td>34,956</td>
<td>August</td>
</tr>
<tr>
<td></td>
<td>33,939</td>
<td>August 2</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>26,160</td>
<td>July 13</td>
<td>25,674</td>
<td>27,238</td>
<td>July</td>
<td>25,674</td>
<td>27,238</td>
<td>July</td>
</tr>
<tr>
<td>Ontario</td>
<td>27,005</td>
<td>August 1</td>
<td>24,560</td>
<td>25,879</td>
<td>August</td>
<td>24,360</td>
<td>25,668</td>
<td>August</td>
</tr>
</tbody>
</table>

For the May - September 2006 period, Figure EX-1 (2006) (from last year’s assessment) \(^{25}\) shows the expected use of the indicated operating procedures under Base Case, expected load assumptions. The expected load level results were based on the probability-weighted average of the seven load levels simulated.

\(^{25}\) See: [http://www.npcc.org/seasonal.cfm](http://www.npcc.org/seasonal.cfm)
SUMMER 2007 MULTI-AREA
PROBABILISTIC RELIABILITY ASSESSMENT

Figure EX-1 (2006)
Range of the Expected Use of Indicated Operating Procedures for Summer 2006
Considering Base Case Assumptions (May – September)
(Expected Load Level)

Figure EX-2 (2006)
Summer 2006 – Expected Use of the Indicated Operating Procedures
Severe Case Assumptions, Extreme Load Level
(May – September)
For the May - September 2006 period, Figure EX-2 (2006) (from last year’s assessment) shows the expected use of the indicated operating procedures under the Severe Case assumptions for the extreme load level (which represents the second to highest load level, having approximately a 6% chance of occurring).

When comparing actual occurrences with the estimates, it is important to recognize that Areas may invoke these actions in any order, depending on the situation faced at the time.

With this in mind, the Working Group believes that modeling and assumptions used in the analyses provided a reasonable estimate of the risk of calling on these procedures. Comparison with the results from the last year’s assessment shows that the actual occurrences were within the estimated range.

**PJM Summary**

The PJM Interconnection experienced a new peak demand record for electricity use on August 2nd – the second record in two days and the third for the summer. The new record demand of 144,796 MW occurred at 5:00 p.m. (EDT) on August 2nd and surpassed the record demand of 144,000 MW set on Tuesday, August 1st. PJM’s previous record demand was 139,746 MW set on July 17, 2006.

Market-based demand response contributed 270 MW of capacity during the peak hour on August 2nd. In PJM’s wholesale electricity market, electricity consumers can be paid the market price for electricity for reducing their use of electricity.

A request for voluntary conservation of electricity was in effect August 1st through August 3rd because of high temperatures and humidity. In addition, utility customers on interruptible or curtailable rates were told to reduce their electricity use. These customers agree to eliminate or significantly reduce their use of electricity when told to do so.
Summer 2007 Results
The Working Group modified the Working Group’s 2006 MARS database for the conditions expected for the year 2007. Table 8 shows the estimated annual Loss of Load Expectation (LOLE) calculated from the 2002 load shape for the expected load forecast under Base Case assumptions.

Table 8
Estimated Average Annual LOLE (days/year) - Base Case Assumptions

<table>
<thead>
<tr>
<th></th>
<th>Q</th>
<th>MT</th>
<th>NE</th>
<th>NY</th>
<th>ON</th>
</tr>
</thead>
<tbody>
<tr>
<td>LOLE</td>
<td>&lt;.0005</td>
<td>&lt;.0005</td>
<td>0.007</td>
<td>&lt;.0005</td>
<td>&lt;.0005</td>
</tr>
</tbody>
</table>

Table 10 (see Appendix B) shows the estimated need for the indicated operating procedures (in days/period) for May through September 2007 for the Base Case assumptions for all NPCC Areas for the 2002 load shape assumptions, respectively. Figure 7 shows the range of the expected use of the indicated operating procedures under the Base Case assumptions for the expected and extreme load level. The expected load level results were based on the probability-weighted average of the seven load levels simulated. The extreme load is the second to highest load level, having approximately a 6% chance of occurring.

Figure 7
Range of the Expected Use of the Indicated Operating Procedures for Summer 2007 Base Case Assumptions (May – September) (Expected and Extreme Load Levels)
SUMMER 2007 MULTI-AREA PROBABILISTIC RELIABILITY ASSESSMENT

Base Case Assumptions
The following summary of Base Case assumptions represents system conditions consistent with those assumed in the NPCC CO-12 Working Group's "Reliability Assessment for Summer 2007", April 2007. The Base Case assumptions are summarized below:

System
- As-Is System for the year 2007
- Transfers allowed between Areas
- Cross Sound Cable in-service (330 MW)
- Neptune Cable in-service July 1, 2007 (660 MW)
- 2002 Load Shape adjusted to Area’s year 2007 forecast (expected and extreme assumptions)

PJM-RTO
- As-Is System for the Summer 2007 period
- Neptune Cable in-service July 2007 (660 MW)
- Based on the PJM 2006 Reserve Requirement studies
- 2002 Load Shapes adjusted to the 2007 forecast provided by PJM
- Load forecast uncertainty of 93.66 % +/- 5.5%, 11%, and 16.5%
- Operating Reserve 3,400 MW
  (30-min. 2,765 MW; 10-min. 634 MW)

RFC ‘Other’
- As-Is System for the Summer 2007 period
- 2002 Load Shapes adjusted to the 2007 forecast provided by PJM
- Load forecast uncertainty of 91.83% +/- 7%, 14%, and 21%
- Operating Reserve 2,206 MW
  (30-min. 1,470 MW; 10-min. 736 MW)

MRO-US
- As-Is System for the Summer 2007 period
- 2002 Load Shapes adjusted to the 2007 forecast provided by PJM
- Load forecast uncertainty of 92.75% +/- 6.2 %, 12.5 %, and 18.7%
- Operating Reserve 1,700 MW
  (30-min. 1,200 MW; 10-min. 500 MW)

Ontario
- Forecast consistent with the IESO’s 2007Q1 18-Month Outlook published in March, 2007
- Goreway Station Phase 1 (485 MW) in-service 2007-Q2

26 See: http://www.pjm.com/committees/working-groups/rrawg/rrawg.html
SUMMER 2007 MULTI-AREA
PROBABILISTIC RELIABILITY ASSESSMENT

- Price Sensitive Demand Response (effective) ranges from 386 MW to 552 MW during the study period
- ~ 395 MW of installed Wind Generation
  (10% capacity on peak assumed)

New England
- All existing capacity modeled
- No additions and attrition assumed
- Approximately 762 MW Demand Response Program, including:
  Real-Time Demand Response
  Real-Time Profiled Response
- NSTAR 345 kV Phase I transmission reliability project assumed complete
  Boston Import Limit = 4,600 MW
- SWCT 345 kV Phase I transmission reliability project in-service
  SWCT Import Limit = 2,350 MW
  Norwalk/Stamford Import Limit = 1,300 MW

New York
- All cables in service
- Firm contracts across Cross Sound Cable
- Neptune Cable in-service July 2007
- Unit additions:
  180 MW of new wind generation
  (~11% capacity factor at summer peak hours)
  Maple Ridge Phase 2 - 100 MW
  80 MW Prattsburg Wind Park
- Retirements of 388 MW
- 2,903 MW of external Contracts, including:
  1,000 MW from Quebec
  330 MW from NE 27 (over the Cross Sound Cable)
  1,300 MW from PJM
- 1,220 MW of effective load reduction from SCR and EDRP

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27 Summer capacity auctions at this time have not provided any capacity other than 330 MW to New York from New England.
New York
The Base Case assumes that the New York City and Long Island localities will meet their locational installed capacity requirements as described in the February 16, 2007 New York ISO report \(^{28}\) - "Locational Installed Capacity Requirements Study covering the New York Control Area for the 2007 – 2008 Capability Year" and New York State will meet the capacity requirements described in the “New York Control Area Installed Capacity Requirements for the Period May 2007 – April 2008” New York State Reliability Council, January 5, 2007 Technical Study Report. \(^{29}\)

The New York unit ratings were obtained from the “2006 Load & Capacity Data of the NYISO” (Gold Book \(^{30}\)). The following changes (nominal ratings shown) announced after the Gold Book was published were modeled in this study:

**Existing Resources**
All in-service New York generation resources were modeled.

**Retirements:**

<table>
<thead>
<tr>
<th>Project Name</th>
<th>(MW)</th>
<th>Location</th>
</tr>
</thead>
<tbody>
<tr>
<td>Huntley 65 &amp; 66</td>
<td>165</td>
<td>Zone A</td>
</tr>
<tr>
<td>Lovett 3</td>
<td>47</td>
<td>Zone G</td>
</tr>
<tr>
<td>Lovett 5</td>
<td>176</td>
<td>Zone G</td>
</tr>
</tbody>
</table>

**New Units: (Units installed during 2006)**

<table>
<thead>
<tr>
<th>Project Name</th>
<th>(MW)</th>
<th>Location</th>
</tr>
</thead>
<tbody>
<tr>
<td>SCS Astoria</td>
<td>500</td>
<td>Zone J</td>
</tr>
<tr>
<td>Ginna Nuclear Plant Uprate</td>
<td>95</td>
<td>Zone B</td>
</tr>
</tbody>
</table>

**Planned Units for 2007**
These units had a signed interconnection agreement by August 1, 2006.

<table>
<thead>
<tr>
<th>Project Name</th>
<th>(Nameplate - MW)</th>
<th>Location</th>
</tr>
</thead>
<tbody>
<tr>
<td>Prattsburgh Wind Park</td>
<td>80</td>
<td>Zone B</td>
</tr>
<tr>
<td>Maple Ridge Wind Power Phase 2</td>
<td>100</td>
<td>Zone E</td>
</tr>
</tbody>
</table>

Wind generators were modeled as hourly load modifiers. For example, the New York ISO has stated that the output of the unit varies between 0 and 198 MW based on wind

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data collected near the Flat Rock site during 2002. This 2002 hourly wind data corresponds to the 2002 hourly load shape also used in this assessment. Characteristics of this data indicate an overall 30% capacity factor, with a capacity factor of approximately 11% during the summer peak hours.

### Special Case Resources and Emergency Demand Response Programs

<table>
<thead>
<tr>
<th>SCR Registered (MW)</th>
<th>EDRP Modeled (MW)</th>
<th>Location</th>
</tr>
</thead>
<tbody>
<tr>
<td>605.8</td>
<td>124</td>
<td>upstate New York</td>
</tr>
<tr>
<td>324.6</td>
<td>42</td>
<td>New York City</td>
</tr>
<tr>
<td>149.6</td>
<td>62</td>
<td>Long Island</td>
</tr>
<tr>
<td><strong>1,080</strong></td>
<td><strong>228</strong></td>
<td><strong>Total</strong></td>
</tr>
</tbody>
</table>

Special Case Resources (SCRs) are loads capable of being interrupted on demand, and distributed generators, rated 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.

For this study, the New York ISO recommended that the SCR programs be modeled as a 1,080 MW operating procedure step, discounted to 994 MW in July and August (and further discounted in other months proportionally to the monthly peak load).

The EDRPs were modeled as a 228 MW operating procedure with a limit of five calls per month. Based on the operational experience of the NYISO with the EDRP programs, the amount modeled represents a discounted amount from the forecast registered amount of approximately 507 MW.

Since customer participation in these programs varies over time, it is recognized that the actual amount of SCR/EDRP resources available for this summer may be different than the amount assumed in this study. The New York ISO believes the value modeled in this study represents a reasonable approximation for this analysis.

### New England

The New England generating unit’s ratings were consistent with those used for the 2007/2008 Installed Capacity Requirement calculation. A summary of these assumptions follows:
Existing Resources
All in-service New England generation resources were modeled.

Retirements
No retirements and/or deactivations were assumed for this study.

2006 Resource Changes

<table>
<thead>
<tr>
<th>Name</th>
<th>MW</th>
<th>Modification</th>
</tr>
</thead>
<tbody>
<tr>
<td>Vermont Yankee</td>
<td>110</td>
<td>Nuclear uprate</td>
</tr>
<tr>
<td>Millstone 3</td>
<td>25</td>
<td>Nuclear uprate</td>
</tr>
<tr>
<td>Seabrook</td>
<td>22</td>
<td>Nuclear uprate</td>
</tr>
<tr>
<td>Devon 10</td>
<td>14</td>
<td>Reactivation</td>
</tr>
</tbody>
</table>

Units planned for operation in 2007
A total of 96 MW of new capacity is considered likely to be in-service during the summer of 2007 (7 MW by July and 89 MW by September). However, resources not in-service by June 1st were not included in this study.

Summer 2007 Load Response Program (LRP)
It is anticipated that the New England LRP 31 program will provide additional load relief utilizing market mechanisms in the summer of 2007. Per the ISO-NE Load Response Manual 32 (effective April 7, 2006), any assets enrolled within the Day-Ahead Load Response, Real-Time Demand Response, and Real-Time Profiled response programs are eligible to receive installed capability credit. Resources enrolled in these programs as of January 2007 and ready to respond were included in this study.

A total of 762 MW was been assumed by ISO-NE for this study (derated and modeled as an unforced amount of 616 MW) as one of the steps on the list of New England operating control actions. As market participants continue to sign up additional resources under the LRP, it is recognized that the actual amount of LRP resources may be different than the amount assumed in this study. ISO-NE believes the value modeled in this study represents a reasonable approximation for this analysis.

Southwest Connecticut Emergency Capability RFP

32 See: http://www.iso-ne.com/rules_proceds/isone_mnls/m_lrp_load_response_program (revision 9) 04 07 06.doc
SUMMER 2007 MULTI-AREA PROBABILISTIC RELIABILITY ASSESSMENT

In December 2003, ISO-NE issued a Request for Proposals (RFP) for up to 300 MW or more emergency supplemental capacity to meet critical near-term electric system reliability needs in southwestern Connecticut (SWCT). For this study, ISO-NE has modeled the response to the RFP as 255 MW (derated to account for the assumed availability) of SWCT load reduction.

Ontario

For the purposes of this study, the Base Case assumptions for Ontario are consistent with the IESO “18-Month Outlook: An Assessment of the Reliability of the Ontario Electricity System” (dated March 9, 2007, available from the IESO web site).

Existing Resources

All in-service Ontario generation resources were modeled.

2006 Resource Additions

The following significant generation addition came into service since the last summer assessment:

<table>
<thead>
<tr>
<th>Facility</th>
<th>Fuel Type</th>
<th>Capacity (MW)</th>
<th>In-Service Date</th>
</tr>
</thead>
<tbody>
<tr>
<td>Prince I Wind Farm</td>
<td>Wind</td>
<td>99</td>
<td>2006 Q3</td>
</tr>
<tr>
<td>Prince II Wind Power Project</td>
<td>Wind</td>
<td>90</td>
<td>2006 Q3</td>
</tr>
</tbody>
</table>

2007 Resource Additions

The following resources were assumed to be available for the summer of 2007:

<table>
<thead>
<tr>
<th>Facility</th>
<th>Zone</th>
<th>Fuel Type</th>
<th>Capacity (MW)</th>
<th>In-Service Date</th>
</tr>
</thead>
<tbody>
<tr>
<td>Abitibi Canyon</td>
<td>Northeast</td>
<td>Water</td>
<td>20 (upgrade)</td>
<td>2007 Q1</td>
</tr>
<tr>
<td>Trail Road Landfill Gas</td>
<td>Ottawa</td>
<td>Landfill Gas</td>
<td>5</td>
<td>2007 Q1</td>
</tr>
<tr>
<td>Goreway Station Phase I</td>
<td>Toronto</td>
<td>Gas</td>
<td>485</td>
<td>2007 Q2</td>
</tr>
</tbody>
</table>

For the purposes of this assessment, the IESO assumed that wind generation has a dependable contribution of 10% of the generation capacity listed above.

For Curtail Load/Utility Surplus, the IESO assumed 491 MW, consisting of 188 MW from Utility Surplus (a/k/a “Stretch” Capability) and 115 MW from the Emergency Demand Response Program.

Price Sensitive Demand Response was assumed to range from 386 MW to 552 MW during the summer 2007 study period (May to September).

33 See http://www.iso-ne.com/nwsssp/pr/2004/SWCT_RFP_041604.doc:
The IESO continues to facilitate the Emergency Load Response Program (ELRP). The ELRP is modeled as one of the steps on the list of operating control actions. The best estimate for this program is that about 159 MW of load will be available to respond if/when required.

Further information regarding the IESO’s ELRP program can be found on the IESO web-site. When reviewing information on this web-site, it should be recognized that the ELRP was initially named the Reliability Demand Response Program.

**Retirements**
None.

---

Severe Case Scenario

Table 9 shows the estimated annual Loss of Load Expectation (LOLE) calculated from the 2002 load shape for the expected load forecast under Severe Case assumptions.

Table 9
Estimated Average Annual LOLE (days/year)
Severe Assumptions Scenario

<table>
<thead>
<tr>
<th></th>
<th>Q</th>
<th>MT</th>
<th>NE</th>
<th>NY</th>
<th>ON</th>
</tr>
</thead>
<tbody>
<tr>
<td>LOLE</td>
<td>&lt;.0005</td>
<td>&lt;.0005</td>
<td>0.018</td>
<td>0.009</td>
<td>&lt;.0005</td>
</tr>
</tbody>
</table>

Table 12 (see Appendix B) show the estimated need for the indicated operating procedures (in days/period) during May through September 2007 for the Severe Case Scenario for all NPCC Areas for the 2002 load shape assumptions. The New England and New York Areas are expected to need to use these procedures in response to a capacity deficiency for this Scenario. Tables 12(a) and (b) show the corresponding results for the New York City, Boston, MA, and southwestern Connecticut localities, respectively (for the 2002 load shape assumption).

Figure 8 shows the expected use of the indicated operating procedures occurrences for under the Severe Case assumptions for the expected load. The expected load level results were based on the probability-weighted average of the seven load levels simulated.

Figure 9 shows the corresponding results for the extreme load (represents the second to highest load level, having approximately a 6% chance of occurring).
The Severe Case Scenario assumptions are summarized below:

**System**
- As-Is System for the year 2007
- Transfers allowed between Areas
- Transfer capability between NPCC and neighboring Areas reduced by 50%
- Cross Sound Cable assumed available w/o contracts
- Neptune Cable unavailable
- 2002 Load Shape adjusted to Area’s year 2007 forecast (expected and extreme assumptions)

**PJM-RTO**
- As-Is System for the Summer 2007 period
- Neptune Cable unavailable
- Based on the PJM 2006 Reserve Requirement studies
- 2002 Load Shapes adjusted to the 2007 forecast provided by PJM
- Load forecast uncertainty of 93.66 % +/- 5.5%, 11%, and 16.5%
- Operating Reserve 3,400 MW
  (30-min. 2,765 MW; 10-min. 634 MW)

36 See: [http://www.pjm.com/committees/working-groups/rrawg/rrawg.html](http://www.pjm.com/committees/working-groups/rrawg/rrawg.html)
RFC ‘Other’
- As-Is System for the Summer 2007 period
- 2002 Load Shapes adjusted to the 2007 forecast provided by PJM
- Load forecast uncertainty of 91.83% +/- 7%, 14%, and 21%
- Operating Reserve 2,206 MW
  (30-min. 1,470 MW; 10-min. 736 MW)

MRO-US
- As-Is System for the Summer 2007 period
- 2002 Load Shapes adjusted to the 2007 forecast provided by PJM
- Load forecast uncertainty of 92.75% +/- 6.2 %, 12.5 %, and 18.7%
- Operating Reserve 1,700 MW
  (30-min. 1,200 MW; 10-min. 500 MW)

Ontario
- ~750 MW of maintenance extended into the summer period
- ~307 MW of Price Sensitive Demand Response
  (~ 245 MW lower than the Base Case value)
- Goreway station in-service delayed beyond study period
- Hydro resource energy 20% lower than Base Case
  (5% reduction in capacity)

New England
- NSTAR 345 kV Phase I transmission reliability project partially delayed
  3164 cable already in service
  The other cable assumed delayed
- 50% reduction in Demand Response Program assumed
- Maintenance overrun by 4 weeks

New York
- Advance retirement of upstate units totaling 230 MW
- Extended maintenance of Nuclear Unit throughout summer
- Contracts totaling 1,913 MW
- Cross Sound Cable available only for emergency assistance
  (i.e., w/o firm contracts)
- Neptune Cable unavailable
- 50% reduction in effectiveness of SCR and EDRP programs
Conclusions
Use of the indicated operating procedures designed to mitigate resource shortages (specifically, reducing 30-minute reserve, voltage reduction, reducing 10-minute reserve, and public appeals) is not expected for the NPCC Areas during the 2007 summer period under the Base Case, expected load assumptions. The expected load level is the probability-weighted average of the seven load levels assumed. The expected usage of these operating procedures is significantly less than one occurrence.

Recently added capacity in the NPCC Areas, in addition to the Demand Response Programs and transmission projects planned to be available this year are contributing factors that tend to reduce the need for the use of these operating procedures in 2007.

If reductions in anticipated resources, delay of expected transmission projects and/or additional transmission limitations into NPCC materialize coincident with higher than expected loads, New York and New England may experience conditions during the summer of 2007 that require the use of their operating procedures designed to mitigate resource shortages.

Assuming higher than expected (having approximately a 6% chance of occurring) load and severe conditions (for example, the 660 MW Neptune Cable Project to Long Island NY not in-service, the New England to Long Island Cross Sound Cable available only for emergency transfers, demand-side programs impacts reduced by 50%, among other assumptions), the potential use of these operating procedures is more likely to be required in New York City and Long Island, NY, and, to a lesser extent, in Boston, MA, and southwestern CT.
Objective and Scope of Work

1. **Objective**
   Using the G.E. Multi-Area Reliability Simulation (MARS) program, review NPCC Area reliability resulting from the anticipated resource and transmission capacity reported for the year 2007 under Base Case and Severe Case assumptions, and summarize the range of results for the summer and shoulder season months (the period from May to September).

2. **Scope**
   In meeting this objective, the CP-8 Working Group will review the short-term resource adequacy of NPCC and neighboring Areas for the year 2007, recognizing uncertainty in forecasted demand, scheduled outages of transmission, forced and scheduled outages of generation facilities, and the impact of proposed load response programs. Reliability will be measured by calculating the Loss of Load Expectation (LOLE) and estimated use of Area emergency operating procedures. A report summarizing the results of the assessment will be published no later than May 4, 2007. The assessment will:

   1. Review last summer’s CP-8 Working Group Summer assessments with respect to actual Area experience;
   2. Consider the impacts of Sub-Area transmission constraints;
   3. Incorporate, to the extent possible, a detailed GE MARS reliability representation for the regions bordering NPCC;
   4. Coordinate assessment assumptions with the NPCC Task Force on Coordination of Operations; and,
   5. Examine any impact of evolving market rules on overall NPCC interconnection assistance and other assumptions.
## Table 10 - Base Case Assumptions

Expected Need for Indicated Operating Procedures (days/period)

(Occurrences 0.5 or greater are highlighted)

<table>
<thead>
<tr>
<th>Base Case</th>
<th>Hydro-Quebec</th>
<th>Maritimes</th>
<th>Area</th>
<th>New England</th>
<th>New York</th>
<th>Ontario</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>30-min VR</td>
<td>10-min</td>
<td>Appeal</td>
<td>30-min VR</td>
<td>10-min</td>
<td>Appeal</td>
</tr>
<tr>
<td>2002 Load Shape-Expected Load</td>
<td></td>
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<tr>
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</tr>
<tr>
<td>2002 Load Shape-Extreme Load</td>
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<td></td>
<td></td>
<td></td>
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<tr>
<td>May</td>
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<tr>
<td>May-Sept</td>
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</tr>
</tbody>
</table>

Notes:  
"30-min" - reduce 30-minute Reserve Requirement; "VR" - and initiate Voltage Reduction;  
"10-min" - and reduce 10-minute Reserve Requirement; "Appeal" - and initiate General Public Appeals; "Discon" - and disconnect customer load
### APPENDIX B

#### Table 11 - Severe Case Scenario

**- Expected Need for Indicated Operating Procedures (days/period)**

(Occurrences 0.5 or greater are highlighted)

<table>
<thead>
<tr>
<th>Severe Case Results</th>
<th>Hydro-Quebec</th>
<th>Maritimes Area</th>
<th>New England</th>
<th>New York</th>
<th>Ontario</th>
</tr>
</thead>
<tbody>
<tr>
<td>30-min VR</td>
<td>10-min Appeal</td>
<td>30-min VR</td>
<td>10-min Appeal</td>
<td>Discon</td>
<td>30-min VR</td>
</tr>
<tr>
<td>May</td>
<td>-</td>
<td>-</td>
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<td>-</td>
<td>-</td>
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<td>Jun</td>
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<td>Sept</td>
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<tr>
<td>May-Sept</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>2002 Load Shape-Expected Load</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>May</td>
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<td>Sept</td>
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<tr>
<td>May-Sept</td>
<td>-</td>
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<td>-</td>
</tr>
</tbody>
</table>

Notes:  
"30-min" - reduce 30-minute Reserve Requirement; "VR" - and initiate Voltage Reduction;  
"10-min" - and reduce 10-minute Reserve Requirement; "Appeal" - and initiate General Public Appeals; "Discon" - and disconnect customer load
## APPENDIX B

### Table 12 (a) - Severe Case Scenario – New York City Locality
- Expected Need for Indicated Operating Procedures (days/period)

(Occurrences 0.5 or greater are highlighted)

<table>
<thead>
<tr>
<th>Severe Case Results</th>
<th>Area - J (NYC)</th>
<th>Area K (LI)</th>
<th>New York</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>30-min</td>
<td>VR</td>
<td>Appeal</td>
</tr>
<tr>
<td>2002 Load Shape – Expected Load</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>May</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>Jun</td>
<td>0.002</td>
<td>0.001</td>
<td>-</td>
</tr>
<tr>
<td>Jul</td>
<td>0.269</td>
<td>0.147</td>
<td>0.057</td>
</tr>
<tr>
<td>Aug</td>
<td>0.195</td>
<td>0.097</td>
<td>0.033</td>
</tr>
<tr>
<td>Sept</td>
<td>0.001</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>May-Sept</td>
<td>0.467</td>
<td>0.245</td>
<td>0.090</td>
</tr>
<tr>
<td>2002 Load Shape – Extreme Load</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>May</td>
<td>0.001</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>Jun</td>
<td>0.021</td>
<td>0.002</td>
<td>0.001</td>
</tr>
<tr>
<td>Jul</td>
<td>2.481</td>
<td>1.542</td>
<td>0.592</td>
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<tr>
<td>Aug</td>
<td>1.737</td>
<td>0.871</td>
<td>0.304</td>
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<tr>
<td>Sept</td>
<td>0.005</td>
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<tr>
<td>May-Sept</td>
<td>4.245</td>
<td>2.415</td>
<td>0.897</td>
</tr>
</tbody>
</table>

Notes: 
"30-min" - reduce 30-minute Reserve Requirement; "VR" – and initiate Voltage Reduction; 
"10-min" – and reduce 10-minute Reserve Requirement; "Appeal" - and initiate General Public Appeals; "Discon" – and disconnect customer load
### APPENDIX B

#### Table 12(b) - Severe Case Scenario – Boston, MA & Southwestern Connecticut
- Expected Need for Indicated Operating Procedures (days/period)

(Occurrences ≥0.5 or greater are highlighted)

<table>
<thead>
<tr>
<th>Severe</th>
<th>Case Results</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>SW CT</td>
</tr>
<tr>
<td></td>
<td>30-min</td>
</tr>
<tr>
<td></td>
<td></td>
</tr>
<tr>
<td>2002 Load Shape – Expected Load</td>
<td></td>
</tr>
<tr>
<td>May</td>
<td>0.001</td>
</tr>
<tr>
<td>Jun</td>
<td>0.042</td>
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<tr>
<td>Jul</td>
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<tr>
<td>Aug</td>
<td>0.082</td>
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<tr>
<td>Sept</td>
<td></td>
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<tr>
<td>May-Sept</td>
<td>0.125</td>
</tr>
<tr>
<td>2002 Load Shape - Extreme Load</td>
<td></td>
</tr>
<tr>
<td>May</td>
<td>0.003</td>
</tr>
<tr>
<td>Jun</td>
<td>0.181</td>
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<tr>
<td>Jul</td>
<td>0.002</td>
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<tr>
<td>Aug</td>
<td>0.509</td>
</tr>
<tr>
<td>Sept</td>
<td></td>
</tr>
<tr>
<td>May-Sept</td>
<td>0.693</td>
</tr>
</tbody>
</table>

Notes:
- "30-min" - reduce 30-minute Reserve Requirement; "VR" – and initiate Voltage Reduction;
- "10-min" – and reduce 10-minute Reserve Requirement; "Appeal" - and initiate General Public Appeals; "Discon" – and disconnect customer load
APPENDIX C

Multi-Area Reliability Simulation Program Description

General Electric’s Multi-Area Reliability Simulation (MARS) program 37 allows assessment of the reliability of a generation system comprised of any number of interconnected areas.

Modeling Technique

A sequential Monte Carlo simulation forms the basis for MARS. The Monte Carlo method allows for many different types of generation and demand-side options.

In the sequential Monte Carlo simulation, chronological system histories are developed by combining randomly generated operating histories of the generating units with the inter-area transfer limits and the hourly chronological loads. Consequently, the system can be modeled in great detail with accurate recognition of random events, such as equipment failures, as well as deterministic rules and policies that govern system operation.

Reliability Indices

The following reliability indices are available on both an isolated (zero ties between areas) and interconnected (using the input tie ratings between areas) basis:

- Daily Loss of Load Expectation (LOLE - days/year)
- Hourly LOLE (hours/year)
- Loss of Energy Expectation (LOEE -MWh/year)
- Frequency of outage (outages/year)
- Duration of outage (hours/outage)
- Need for initiating Operating Procedures (days/year or days/period)

The Working Group used both the daily LOLE and Operating Procedure indices for this analysis. The use of Monte Carlo simulation allows for the calculation of probability distributions, in addition to expected values, for all of the reliability indices. These values can be calculated both with and without load forecast uncertainty.

The MARS program probabilistically models uncertainty in forecast load and generator unit availability. The program calculates expected values of Loss of Load Expectation (LOLE) and can estimate each Area's expected exposure to their Emergency Operating Procedures. Scenario analysis is used to study the impacts of extreme weather conditions, variations in expected unit in-service dates, overruns in planned scheduled maintenance, or transmission limitations.

Resource Allocation Among Areas

The first step in calculating the reliability indices is to compute the area margins on an isolated basis, for each hour. This is done by subtracting from the total available capacity in the area for the hour the load demand for the hour. If an area has a positive or zero margin, then it has sufficient capacity to meet its load. If the area margin is negative, the load exceeds the capacity available to serve it, and the area is in a loss-of-load situation.

APPENDIX C

If there are any areas that have a negative margin after the isolated area margins have been adjusted for curtailable contracts, the program will attempt to satisfy those deficiencies with capacity from areas that have positive margins. Two methods are available for determining how the reserves from areas with excess capacity are allocated among the areas that are deficient. In the first approach, the user specifies the order in which an area with excess resources provides assistance to areas that are deficient. The second method shares the available excess reserves among the deficient areas in proportion to the size of their shortfalls. The user can also specify that areas within a pool will have priority over outside areas. In this case, an area must assist all deficient areas within the same pool, regardless of the order of areas in the priority list, before assisting areas outside of the pool. Pool-sharing agreements can also be modeled in which pools provide assistance to other pools according to a specified order.

Generation

MARS has the capability to model the following different types of resources:
- Thermal
- Energy-limited
- Cogeneration
- Energy-storage
- Demand-side management

An energy-limited unit can be modeled stochastically as a thermal unit with an energy probability distribution (Type 1 energy-limited unit), or deterministically as a load modifier (Type 2 energy-limited unit). Cogeneration units are modeled as thermal units with an associated hourly load demand. Energy-storage and demand-side management impacts are modeled as load modifiers.

For each unit modeled, the installation and retirement dates and planned maintenance requirements are specified. Other data such as maximum rating, available capacity states, state transition rates, and net modification of the hourly loads are input depending on the unit type.

The planned outages for all types of units in MARS can be specified by the user or automatically scheduled by the program on a weekly basis. The program schedules planned maintenance to levelize reserves on either an area, pool, or system basis. MARS also has the option of reading a maintenance schedule developed by a previous run and modifying it as specified by the user through any of the maintenance input data. This schedule can then be saved for use by subsequent runs.

Thermal Units

In addition to the data described previously, thermal units (including Type 1 energy-limited units and cogeneration) require data describing the available capacity states in which the unit can operate. This is input by specifying the maximum rating of each unit and the rating of each capacity state as a per unit of the unit's maximum rating. A maximum of eleven capacity states are allowed for each unit, representing decreasing amounts of available capacity as governed by the outages of various unit components.
APPENDIX C

Because MARS 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 you assume 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:

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

If detailed transition rate data for the units is not available, MARS can approximate the transition rates from the partial forced outage rates and an assumed number of transitions between pairs of capacity states. Transition rates calculated in this manner will give accurate results for LOLE and LOEE, but it is important to remember that the assumed number of transitions between states will have an impact on the time-correlated indices such as frequency and duration.

Energy-Limited Units

Type 1 energy-limited units are modeled as thermal units whose capacity is limited on a random basis for reasons other than the forced outages on the unit. This unit type can be used to model a thermal unit whose operation may be restricted due to the unavailability of fuel, or a hydro unit with limited water availability. It can also be used to model technologies such as wind or solar; the capacity may be available but the energy output is limited by weather conditions.

Type 2 energy-limited units are modeled as deterministic load modifiers. They are typically used to model conventional hydro units for which the available water is assumed to be known with little or no uncertainty. This type can also be used to model certain types of contracts. A Type 2 energy-limited unit is described by specifying a maximum rating, a minimum rating, and a monthly available energy. This data can be changed on a monthly basis. The unit is scheduled on a monthly basis with the unit's minimum rating dispatched for all of the hours in the month. The remaining capacity and energy can be scheduled in one of two ways. In the first method, it is scheduled deterministically so as to reduce the peak loads as much as possible. In the second approach, the peak-shaving portion of the unit is scheduled only in those hours in which the available thermal capacity is not sufficient to meet the load; if there is sufficient thermal capacity, the energy of the Type 2 energy-limited units will be saved for use in some future hour when it is needed.
APPENDIX C

Cogeneration
MARS models cogeneration as a thermal unit with an associated load demand. The difference between the unit's available capacity and its load requirements represents the amount of capacity that the unit can contribute to the system. The load demand is input by specifying the hourly loads for a typical week (168 hourly loads for Monday through Sunday). This load profile can be changed on a monthly basis. Two types of cogeneration are modeled in the program, the difference being whether or not the system provides back-up generation when the unit is unable to meet its native load demand.

Energy-Storage and DSM
Energy-storage units and demand-side management impacts are both modeled as deterministic load modifiers. For each such unit, the user specifies a net hourly load modification for a typical week which is subtracted from the hourly loads for the unit's area.

Transmission System
The transmission system between interconnected areas is modeled through transfer limits on the interfaces between pairs of areas. The transfer limits are specified for each direction of the interface and can be changed on a monthly basis. Random forced outages on the interfaces are modeled in the same manner as the outages on thermal units, through the use of state transition rates.

Contracts
Contracts are used to model scheduled interchanges of capacity between areas in the system. These interchanges are separate from those that are scheduled by the program as one area with excess capacity in a given hour provides emergency assistance to a deficient area.

Each contract can be identified as either firm or curtailable. Firm contracts will be scheduled regardless of whether or not the sending area has sufficient resources on an isolated basis, but they can be curtailed because of interface transfer limits. Curtailable contracts will be scheduled only to the extent that the sending Area has the necessary resources on its own or can obtain them as emergency assistance from other areas.