Northeast Power Coordinating Council
Multi-Area Probabilistic Reliability Assessment
For
Winter 2005/06

November 18, 2005

Conducted by the
NPCC CP-8 Working Group
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The CP-8 Working Group acknowledges the efforts of Mr. Glenn Haringa, GE Energy, Mr. Andrew Ford, the PJM Interconnection, Messrs. Scott Hodgdon and Fei Zeng, ISO-New England, 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 less than one occurrence for the NPCC Areas during the 2005/06 winter period for the expected load level under the Base and Severe Case conditions simulated. The expected load level results were based on the probability-weighted average of the seven load levels simulated.

However, if reductions in anticipated resources and/or additional transmission limitations into NPCC materialize coincident with higher than expected loads, Ontario, New England, Québec and the Maritimes Areas may experience conditions during the winter of 2005/06 that require the use of their operating procedures designed to mitigate resource shortages.

This winter, a significant amount of natural gas production may not be available to interstate pipelines serving the Atlantic seaboard, due to the effects of Hurricanes Katrina and Rita on Gulf Coast energy production. While New England has diverse natural gas supplies, including strong pipeline connections with Canada and imported liquefied natural gas, New England depends on two major interstate pipelines to bring in Gulf Coast natural gas. To the extent supply or delivery constraints arise, most of New England’s gas-only fired power plants could be adversely affected as a result of the “non-firm” character of their gas supply and transportation services.

ISO New England has plans\(^1\) to mitigate the reliability impact of this winter’s natural gas situation, in part by increased use of oil-fired power plants. Supplies of fuel oil available to power plants and storage facilities accessible by barge or tanker ships are likely to be adequate for the winter. However, harsh winter weather could pose logistical challenges for truck-transported fuel oil shipments to some power plants, thereby affecting the reliability of fuel deliveries. Commercial demand reduction, such as demand response as well as residential energy efficiency and conservation initiatives, will also play an integral part in ensuring the reliability of the region’s bulk power system for the 2005-2006 heating season.

In order to address the possibility that severe cold weather conditions this winter may exacerbate fuel supply and pricing issues for New England generating Resources, ISO-NE has developed a contingency plan for this winter (the “Winter 2005/2006 Action Plan”). The Winter 2005/2006 Action Plan includes the following objectives:

- Communicating the need to reduce consumption in all hours to conserve fuel;
- Encouraging the utilization of dual-fuel generating capability;
- Expanding demand-side management programs in New England in order to help maintain needed Operating Reserves; and,
- Developing Emergency Energy procedures and Market Rules to complement the cold weather procedures set forth in Appendix H of Market Rule 1 to maintain reliability this winter during cold weather conditions.

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EXECUTIVE SUMMARY

Introduction
This study estimated the use of NPCC Area Operating Procedures designed to mitigate resource shortages for the winter of 2005/06 (November 2005 through March 2006). The CP-8 Working Group closely coordinated its efforts with those of the CO-12 Working Group’s study, "NPCC Reliability Assessment for Winter 2005/06", November 2005.

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
For the November 2005 - March 2006 period, Figure EX-1 displays the range of results for the expected load level (the expected load level results were based on the probability-weighted average of the seven load levels simulated) under the Base Case and Severe Case assumptions.

Figure EX-1

Maritimes Area initiates interruptible loads instead of voltage reduction
For the November 2005 - March 2006 period, Figure EX-2 shows the estimated use of the indicated operating procedures under the Severe Case assumptions for the extreme load level (representing the second to highest load level, having approximately a 6% chance of being exceeded).

**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 less than one occurrence for the NPCC Areas during the 2005/06 winter period for the expected load level under the Base and Severe Case conditions. The expected load level results were based on the probability-weighted average of the seven load levels simulated.

As shown in Figure EX-2, if reductions in anticipated resources and/or additional transmission limitations into NPCC materialize coincident with higher than expected loads, Québec, Ontario, New England and the Maritimes Areas are expected to use these operating procedures under extreme load level conditions (represents the second to highest load level, having approximately a 6% chance of being exceeded).

The impact of Hurricanes Katrina and Rita on Gulf Coast energy production has limited the exploration, production and refining capacity of the oil and gas supply from that region. In order to assess the extent of this situation, ISO-NE initiated a study with...
Levitan and Associates, Inc.\textsuperscript{2} to assess the potential impact of Hurricanes Katrina and Rita on the coming winter.

This winter, a significant amount of natural gas production may not be available to interstate pipelines serving the Atlantic seaboard. New England has diverse natural gas supplies, including strong pipeline connections with Canada and imported liquefied natural gas (LNG). However, the region depends on two major interstate pipelines to bring in Gulf Coast natural gas. To the extent supply or delivery constraints arise, most of the region’s gas-fired power plants could be adversely affected as a result of the “non-firm” character of their gas supply and transportation services.

ISO New England has plans\textsuperscript{3} to mitigate the reliability impact of this winter’s natural gas situation, in part by increased use of oil-fired power plants. Supplies of fuel oil available to power plants and storage facilities accessible by barge or tanker ships are likely to be adequate for the winter. However, harsh winter weather could pose logistical challenges for truck-transported fuel oil shipments to some power plants, thereby affecting the reliability of fuel deliveries. Commercial demand reduction, such as demand response as well as residential energy efficiency and conservation initiatives, will also play an integral part in ensuring the reliability of the region’s bulk power system for the 2005-2006 heating season.

In order to address the possibility that severe cold weather conditions this winter may exacerbate fuel supply and pricing issues for New England generating Resources, ISO-NE has developed a contingency plan for this winter (the “Winter 2005/2006 Action Plan”). The Winter 2005/2006 Action Plan includes the following objectives:

\begin{itemize}
  \item Communicating the need to reduce consumption in all hours to conserve fuel;
  \item Encouraging the utilization of dual-fuel generating capability;
  \item Expanding demand-side management programs in New England in order to help maintain needed Operating Reserves; and,
  \item Developing Emergency Energy procedures and Market Rules to complement the cold weather procedures set forth in Appendix H of Market Rule 1 to maintain reliability this winter during cold weather conditions.
\end{itemize}

\textsuperscript{3} See: http://www.iso-ne.com/regulatory/ferc/filings/2005/oct/er06-___winter_project_filing2_10-28-05.pdf
INTRODUCTION

This study estimated the use of NPCC Area operating procedures to mitigate resource shortages for November 2005 through March 2006. The Working Group closely coordinated its efforts with the NPCC CO-12 Working Group’s study, "NPCC Reliability Assessment for Winter 2005/06", November 2005.

The development of this Working Group was in response to the following recommendation from the "NPCC Reliability Assessment for Winter 2004/05", December 2004:

“The CO-12 assessment of the Summer Operating Period is accompanied by a corresponding multi area probabilistic assessment of Loss of Load Expectations and of the projected use of Operating Procedures designed to mitigate resource shortages. This assessment was not performed for this Winter Operating Period. For completeness in the assessment of the Winter Operating Period, the CO-12 Working Group recommends that TFCO and TFCP review the merits of having this assessment performed for future Winter Operating Periods.”

The database developed by the previous NPCC CP-8 Working Group's "NPCC Summer 2005 Multi-Area Probabilistic Reliability Assessment", April 2005, 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 winter 2005/06 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.
MODEL ASSUMPTIONS

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 NPCC Area's winter peak load assumptions for the winter 2005/06.

Table 1
Assumed NPCC 2005/06 Winter Peak Loads – MW

<table>
<thead>
<tr>
<th>Area</th>
<th>2002/03 Load Shape</th>
<th>2003/04 Load Shape</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Expected Peak</td>
<td>Extreme Peak *</td>
</tr>
<tr>
<td>Québec</td>
<td>36,463</td>
<td>39,876</td>
</tr>
<tr>
<td>Maritimes Area**</td>
<td>5,553</td>
<td>6,108</td>
</tr>
<tr>
<td>New England</td>
<td>22,830</td>
<td>23,861</td>
</tr>
<tr>
<td>New York</td>
<td>26,021</td>
<td>26,828</td>
</tr>
<tr>
<td>Ontario</td>
<td>24,272</td>
<td>26,124</td>
</tr>
</tbody>
</table>

* Extreme Peak represents the second to highest load level, having approximately a 6% chance of being exceeded.

** Maritimes Area represents New Brunswick, Nova Scotia, Prince Edward Island, and the area administrated by the Northern Maine Independent System Administrator (NMISA).

Load Shape
The Working Group used two load shape assumptions for this analysis. The 2002/03 load shape represents a winter weather pattern with a typical expectation of cold days; the 2003/04 load shape represents a weather pattern that includes a consecutive period of cold days.

The growth rate in each month’s peak was used to escalate Area loads to match the Area's winter 2005/06 demand and energy forecasts for both load shapes. The impacts of Demand-Side Management programs were included in each Area's load forecast for both load shapes.

Figures 1(a) and 1(b) show the diversity in the NPCC area load shapes used in this analysis for the 2002/2003 and 2003/04 load shape assumptions, respectively.
The two load shapes generally show the same trend with respect to coincidence and illustrate the degree of seasonal diversity.
Load Forecast Uncertainty

Peak load forecast uncertainty was also modeled. The effects on reliability of uncertainties in the peak load forecast, due to weather and/or 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 the load can vary on a monthly basis, Table 2 shows the values assumed for January 2006. 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>
<thead>
<tr>
<th>Area</th>
<th>Per-Unit Variation in Load</th>
</tr>
</thead>
<tbody>
<tr>
<td>Q</td>
<td>1.0936 1.0936 1.0468 1.0000 0.9532 0.9064 0.9064</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>1.1061 1.0447 0.9972 0.9615 0.9276 0.9125 0.8500</td>
</tr>
<tr>
<td>NY</td>
<td>1.0430 1.0310 1.0160 0.9980 0.9750 0.9440 0.9050</td>
</tr>
<tr>
<td>ON</td>
<td>1.1145 1.0763 1.0382 1.0000 0.9618 0.9237 0.8855</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 winter 2005/06 capacity assumptions for the NPCC Areas used in the analysis for the Base Case and the Severe Case Scenario, respectively. Base Case conditions were chosen to be consistent with the assumptions used in the companion report by the NPCC CO-12 Working Group, "NPCC Reliability Assessment for Winter 2005/06", November 2005.
NPCC WINTER 2005/06
MULTI-AREA PROBABILISTIC RELIABILITY ASSESSMENT

Table 3 (a)
NPCC Capacity and Load Assumptions for January 2006 - MW
Base Case - Expected Load

<table>
<thead>
<tr>
<th></th>
<th>Q 4</th>
<th>MT</th>
<th>NE</th>
<th>NY</th>
<th>ON 5</th>
</tr>
</thead>
<tbody>
<tr>
<td>Assumed Capacity</td>
<td>38,254</td>
<td>6,898</td>
<td>27,624</td>
<td>40,896</td>
<td>30,185</td>
</tr>
<tr>
<td>Purchase/Sale</td>
<td>480</td>
<td>-200</td>
<td>-243</td>
<td>970</td>
<td>0</td>
</tr>
<tr>
<td>Peak Load 6</td>
<td>36,463</td>
<td>5,553</td>
<td>22,830</td>
<td>26,021</td>
<td>24,272</td>
</tr>
<tr>
<td>Scheduled Maintenance 7</td>
<td>0</td>
<td>165 8</td>
<td>1,436</td>
<td>1,449</td>
<td>844</td>
</tr>
</tbody>
</table>

Table 3 (b)
NPCC Capacity and Load Assumptions for January 2006 - MW
Severe Assumptions Scenario - Extreme Load

<table>
<thead>
<tr>
<th></th>
<th>Q 4</th>
<th>MT</th>
<th>NE</th>
<th>NY</th>
<th>ON 5</th>
</tr>
</thead>
<tbody>
<tr>
<td>Assumed Capacity</td>
<td>37,487</td>
<td>6,898</td>
<td>24,618</td>
<td>40,554</td>
<td>29,650</td>
</tr>
<tr>
<td>Purchase/Sale</td>
<td>480</td>
<td>-200</td>
<td>-503</td>
<td>1,230</td>
<td>0</td>
</tr>
<tr>
<td>Peak Load 6</td>
<td>39,876</td>
<td>6,108</td>
<td>23,861</td>
<td>26,828</td>
<td>26,124</td>
</tr>
<tr>
<td>Scheduled Maintenance 7</td>
<td>0</td>
<td>165 8</td>
<td>1,436</td>
<td>1,449</td>
<td>1,601</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". In addition, the following Areas provided the following:

Québec
The planned outages for the winter 2005-2006 period are reflected in this assessment. The volume of planned outages is consistent with historical volumes.

Ontario
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 October 24, 2005).

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

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4 Capacity shown for Québec adjusted for scheduled maintenance.
5 Capacity shown for Ontario has been seasonally adjusted.
6 Based on 2002/03Load Shape assumption.
7 Maintenance shown is for the week of the monthly peak load.
8 Includes scheduled maintenance, deratings, and units on lay-up.
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 ¹¹ (GADs) data for similar type
units.

New England
This probabilistic assessment reflects New England generating unit availability
assumptions ¹² 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. In the previous years’ reliability
assessments, generating unit Equivalent Forced Outage Rate (EFOR) were used to
represent the forced unavailability of the generating units. In this assessment, Equivalent
Forced Outage Rate Demand (EFORD) was used to represent the forced unavailability of
the units. A description of the EFOR and EFORD parameters and their differences can be
found at the ISO New England Web site. ¹³

New York
Detailed availability assumptions used for the New York units can be found in the New
York ISO February 17, 2005 report ¹⁴ - "Locational Installed Capacity Requirements
Study covering the New York Control Area for the 2005 – 2006 Capability Year” and the
“New York Control Area Installed Capacity Requirement for the Period May 2005 –
April 2006” New York State Reliability Council, December 10, 2004 report. ¹⁵

Transfer Limits
Figure 2 depicts the system that was represented in this Assessment, showing Area and
assumed Base Case transfer limits for the winter 2005/06 period. New York Area
internal transmission representation was consistent with the assumptions used in the New
York ISO February 17, 2005 report ¹⁴ - "Locational Installed Capacity Requirements
Study covering the New York Control Area for the 2005 – 2006 Capability Year” and the
“New York Control Area Installed Capacity Requirement for the Period May 2005 –
April 2006” New York State Reliability Council, December 10, 2004 report. ¹⁵

New England internal transmission representation was consistent with the assumptions
detailed in the ISO-NE Regional System Plan 2005. ¹⁶

¹¹ See: http://www.nerc.com/~gads/
¹² These unit availability assumptions were used to develop ISO New England 2005/2006 Power Year
Installed Capacity Requirements (Objective Capability Values), which were filed with the Federal
¹³ See: http://www.iso-ne.com/regulatory/ferc/filings/2005/mar/ER05_3_21_05.pdf
¹⁴ See: http://www.nyiso.com/public/webdocs/services/planning/resource_adequacy/locational_installed_capacity
requirement_study_032005.pdf
¹⁵ See: http://www.nysrc.org/pdf/Documents/12-10-04IRMstudy.pdf
¹⁶ See: http://www.iso-ne.com/trans/rsp/index.html
Tie transfer limits between Areas are indicated in Figure 2 with seasonal ratings (S-summer, W-winter) where appropriate. The acronyms and notes used in Figure 2 are defined as follows:

Chur - Churchill Falls  
NOR - Norwalk – Stamford  
NM - Northern Maine  
MANIT - Manitoba  
BHE - Bangor Hydro Electric  
NB - New Brunswick  
ND - Nicolet-Des Cantons  
SW - Southwest (Québec)  
PEI - Prince Edward Island  
JB - James Bay  
CMA - Central MA  
CT - Connecticut  
MN - Minnesota  
W MA - Western MA  
NS - Nova Scotia  
CN - Côte-Nord  
NB - New Brunswick  
NE - Northeast (Ontario)  
VT - Vermont  

17 The phase angle regulator (PAR) installation on the Michigan-Ontario Interface (PS4 on 230 kV circuit L4D) is in-service and at neutral tap position. The 230 kV PAR on circuit L51D (PS51) is also available and at neutral tap position. Agreement of the involved transmission owners, Hydro One and International Transmission Company, is critical in achieving full PAR control on the Ontario-Michigan interconnections. Until necessary agreements are in place PS4 and PS51 will only be operated off neutral tap to prevent 5% voltage reduction in Ontario or Michigan, to prevent shedding firm load or for testing. Therefore it was assumed that the Michigan - Ontario Ties will remain free flowing for the study period. Due to a forced outage, 230 kV circuit B3N (230 kV Scott - Bunce Creek circuit) is expected to be unavailable through the study period.

18 If necessary, transmission congestion between generation in New Brunswick and load in Northern Maine can be overcome by switching additional load in Northern Maine to be radially served from the New Brunswick grid.
Operating Procedures to Mitigate Resource Shortages

Each Control 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 load has to be actually disconnected. Load control measures could include disconnecting interruptible loads, public appeals to reduce demand, and voltage reductions. Other measures could include calling on generation available under emergency conditions, and/or reduced operating reserves.

The need for an Area to begin these operating procedures is modeled in MARS by evaluating the daily Loss of Load Expectation (LOLE) 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 LRP/SCR/EDRP</td>
<td>839</td>
<td>0</td>
<td>260</td>
<td>0</td>
<td>191</td>
</tr>
<tr>
<td>Manual Voltage Reduction</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>2. No 30-min Reserves</td>
<td>500</td>
<td>233</td>
<td>577</td>
<td>600</td>
<td>473</td>
</tr>
<tr>
<td>3. Voltage Reduction or Interruptible Loads *</td>
<td>300</td>
<td>508</td>
<td>1.50% of load</td>
<td>1.52% of load</td>
<td>2.80% of load</td>
</tr>
<tr>
<td>4. No 10-min Reserves</td>
<td>750</td>
<td>625</td>
<td>959</td>
<td>0</td>
<td>945</td>
</tr>
<tr>
<td>General Public Appeals</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>158</td>
<td>0</td>
</tr>
<tr>
<td>5. EDRP</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>1,200</td>
<td>300</td>
</tr>
<tr>
<td>General Public Appeals</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>No 10-min Reserves</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
</tbody>
</table>

* Interruptible Loads for Maritimes Area (implemented only for the Area), Voltage Reduction for all others

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 MAAC assists everyone with equal priority.

Table 5
Priority Order for Providing Area Emergency Assistance

<table>
<thead>
<tr>
<th>Area Providing Assistance</th>
<th>Priority of Assistance</th>
<th>1&lt;sup&gt;ST&lt;/sup&gt;</th>
<th>2&lt;sup&gt;ND&lt;/sup&gt;</th>
</tr>
</thead>
<tbody>
<tr>
<td>Québec</td>
<td></td>
<td>MT ON</td>
<td>NE NY</td>
</tr>
<tr>
<td>Maritimes Area</td>
<td></td>
<td>Q ON</td>
<td>NE NY</td>
</tr>
<tr>
<td>New England</td>
<td></td>
<td>NY</td>
<td>Q MT ON</td>
</tr>
<tr>
<td>New York</td>
<td></td>
<td>NE</td>
<td>Q MT ON</td>
</tr>
<tr>
<td>Ontario</td>
<td></td>
<td>Q MT</td>
<td>NE NY</td>
</tr>
<tr>
<td>Millbank Units</td>
<td></td>
<td>Q</td>
<td>MT</td>
</tr>
<tr>
<td>ECAR</td>
<td></td>
<td>ON</td>
<td>MAAC</td>
</tr>
</tbody>
</table>

Modeling of MAAC and ECAR
For the scenarios studied, a detailed representation of the neighboring regions of MAAC (Mid-Atlantic Area Council) and ECAR (East Central Area Reliability) was assumed. The assumptions are summarized in Table 6.

Table 6
MAAC and ECAR 2005/06 Assumptions

<table>
<thead>
<tr>
<th></th>
<th>MAAC</th>
<th>ECAR</th>
</tr>
</thead>
<tbody>
<tr>
<td>Peak Load (MW)</td>
<td>44,259</td>
<td>89,463</td>
</tr>
<tr>
<td>Peak Month</td>
<td>December</td>
<td>January</td>
</tr>
<tr>
<td>Assumed Capacity (MW)</td>
<td>75,457</td>
<td>127,148</td>
</tr>
<tr>
<td>Operating Reserves</td>
<td>5,700 MW</td>
<td>5% of load</td>
</tr>
<tr>
<td>Curtailable Load</td>
<td>1,300 MW</td>
<td>0</td>
</tr>
<tr>
<td>No 30-min Reserves</td>
<td>4,000 MW</td>
<td>1.7% of load</td>
</tr>
<tr>
<td>Voltage Reduction</td>
<td>800 MW</td>
<td>0</td>
</tr>
<tr>
<td>No 10-min Reserves</td>
<td>1,700 MW</td>
<td>3.3% of load</td>
</tr>
<tr>
<td>Appeals</td>
<td>300 MW</td>
<td>0</td>
</tr>
<tr>
<td>Load Forecast Uncertainty</td>
<td>+/- 4.6%, 9.2%, 13.8%</td>
<td>+/- 3%, 7%, 9%</td>
</tr>
</tbody>
</table>

19 Load and capacity assumptions for ECAR based on NERC’s Electricity, Supply and Demand Database (ES&D) available at: http://www.nerc.com/~esd/

20 Represents per unit variation in load.
The diversity between the NPCC monthly peak loads and those of MAAC and ECAR are shown in Figure 3.

**Figure 3 -2005/06 Projected Monthly Expected Peak Loads for NPCC, MAAC, and ECAR**
NPCC WINTER 2005/06
MULTI-AREA PROBABILISTIC RELIABILITY ASSESSMENT

ANALYSIS

Winter 2005/06 Results

Base Case Scenario
Tables 7(a) and 7(b) (see Appendix B) show the estimated need for the indicated operating procedures (in days/period) for November 2005 through March 2006 period for the Base Case assumptions for all NPCC Areas for the 2002/03 and 2003/04 load shape assumptions, respectively. Figure 7 shows the estimated range of the indicated operating procedures occurrences for the NPCC Areas for the expected load (the expected load level results were based on the probability-weighted average of the seven load levels simulated) and the extreme load (the second to highest load level, having approximately a 6% chance of being exceeded) for the Base Case assumptions.

Figure 7
Potential Range of Use of the Indicated Operating Procedures for Winter 2005/06
Base Case Assumptions (November 2005 – March 2006)
(Expected and Extreme Load Levels)
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 Winter 2005/06", November 2005. The Base Case assumptions are summarized below:

NPCC System
- As-Is System for the 2005/06 period
- Transfers allowed between Areas
- Cross Sound Cable in-service
- No imports from Manitoba or Minnesota
- 2002/03 Load Shape adjusted to Area’s year 2005/06 forecast
  - expected and extreme assumptions
- 2003/04 Load Shape adjusted to Area’s year 2005/06 forecast
  - expected and extreme assumptions

MAAC
- 2002 Load shape adjusted to the 2005/06 forecast provided by PJM
- Load forecast uncertainty of +/- 4.6%, 9.2%, and 13.8%

ECAR
- 2002 Load Shape adjusted to the 2005/06 NERC ES&D forecast
- Load forecast uncertainty of +/- 3%, 7%, and 9%
- Operating Reserve 5% of load (30-min 1.7%; 10-min 3.3%)

Ontario
- Pickering Unit 1 is assumed to come into service prior to the start of the winter study period (515 MW)
- 410 MW of dispatchable demand is forecast to be available at the time of the winter peak

New England
- 316 MW SWCT demand response program
- 5,700 MW of gas-only fired generation unavailable

New York
- All Long Island cables in-service
- 810 MW in-service as of Summer 2005, including:
  - 128 MW of new units on Long Island
  - 394 MW (additional) Bethlehem, NY
  - 288 MW of new units in New York City
- 1,165 MW of load reduction due to EDRP & SCR

---

Québec
To be consistent with the assumptions used by the NPCC CO-12 Working Group, internal purchases from independent power producers were included in the capacity. Internal purchases are discounted by a total of 700 MW based on operational experience or operational constraints. Load management programs are discounted to reflect operational constraints such as number of interruptions per day, week or year.

Hydroelectric unit capacity is adjusted to reflect the impact of reservoir level on the head available. Unit capacity is also discounted to take into account operational restrictions such as ice cover formation, run-of-the-river conditions.

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 New York ISO report 23 - "Locational Installed Capacity Requirements Study covering the New York Control Area for the 2005 – 2006 Capability Year" and New York State will meet the capacity requirements described in the “New York Control Area Installed Capacity Requirement for the Period May 2005 – April 2006” New York State Reliability Council, December 10, 2004 report. 24

The New York unit ratings were obtained from the “2005 Load & Capacity Data of the NYISO” (Gold Book 25). All in-service New York generation resources were modeled.

Special Case Resources and Emergency Demand Response Programs

<table>
<thead>
<tr>
<th>SCR</th>
<th>EDRP</th>
</tr>
</thead>
<tbody>
<tr>
<td>Sold/Modeled (MW)</td>
<td>Registered/Modeled (MW)</td>
</tr>
<tr>
<td>705/650</td>
<td>300/135</td>
</tr>
<tr>
<td>172/157</td>
<td>146/66</td>
</tr>
<tr>
<td>98/90</td>
<td>147/66</td>
</tr>
<tr>
<td>975/897</td>
<td>593/267</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.

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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 975 MW operating procedure step, discounted to 897 MW in July and August (and further discounted in other months proportionally to the monthly peak load).

The EDRPs were modeled as a 267 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 600 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

Demand Response Program (DRP)
It is anticipated that the New England DRP program will provide additional load relief utilizing market mechanisms in the New England System. As of April 1, 2005 there were 581 assets registered in the Demand Response program representing approximately 388 MW of possible load relief.

For this study, ISO-NE has assumed a total of 316 MW under the ISO-NE Load Response Program. This amount was derated and modeled as an unforced amount of 218 MW in this analysis. As NEPOOL Participants continue to sign up additional resources under the DRP, it is recognized that the actual amount of DRP 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
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 215 MW of SWCT load reduction.

28 See: http://www.iso-ne.com/genrion_resrcs/rfps/index.html
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 October 24, 2005, available from the IESO web site). All in-service Ontario generation resources were modeled.

2005 Resource Additions
Pickering G1 is assumed to come into service prior to the start of the winter study period (515 MW). The following resource additions are also forecast to come into service during the study period.

<table>
<thead>
<tr>
<th>Proponent/Project Name</th>
<th>Zone</th>
<th>Fuel Type</th>
<th>Installed Capacity MW</th>
<th>Assumed I/S Date</th>
</tr>
</thead>
<tbody>
<tr>
<td>Greater Toronto Airports Authority</td>
<td>Toronto</td>
<td>Gas</td>
<td>117</td>
<td>2005-Q4</td>
</tr>
<tr>
<td>Kingsbridge Wind Power Project</td>
<td>Southwest</td>
<td>Wind</td>
<td>40</td>
<td>2005-Q4</td>
</tr>
<tr>
<td>Melancthon Grey Wind Project</td>
<td>Southwest</td>
<td>Wind</td>
<td>68</td>
<td>2006-Q1</td>
</tr>
<tr>
<td>Erie Shores Wind Farm</td>
<td>Southwest</td>
<td>Wind</td>
<td>99</td>
<td>2006-Q1</td>
</tr>
</tbody>
</table>

The following other resources were assumed available:
- 191 MW Utility Surplus (a/k/a “Stretch” Capability)
- 300 MW Emergency Demand Response Program

Price Sensitive Demand Response was assumed to range from 383 MW to 410 MW during the study period.

Severe Case Scenario
Tables 8(a) and 8(b) (see Appendix B) show the estimated need for the indicated operating procedures (in days/period) during November 2005 through March 2006 period for the Severe Case Scenario for all NPCC Areas for the 2002/03 and 2003/04 load shape assumptions, respectively. The New England, Ontario, Québec and Maritimes Areas are expected to need to use these procedures in response to a capacity deficiency for this Scenario.

Figure 8 shows the indicated operating procedures occurrences for the NPCC Areas for the expected load (the expected load level results were based on the probability-weighted average of the seven load levels simulated) for the Severe Case assumptions. Figure 9 shows the corresponding results for the extreme load (representing the second to highest load level, having approximately a 6% chance of being exceeded).

---

Figure 8
Winter 2005/06 – Estimated Use of the Indicated Operating Procedures
Severe Case Assumptions, Expected Load Level
(November 2005 – March 2006)

Figure 9
Winter 2005/06 – Estimated Use of the Indicated Operating Procedures
Severe Case Assumptions, Extreme Load Level
(November 2005 – March 2006)
The Severe Case Scenario assumptions are summarized below:

NPCC System
- As-Is System for the year 2005
- Transfers allowed between Areas
- Transfer capability between NPCC and neighboring Areas reduced by 50%
- Cross Sound Cable assumed not-available
- No imports from Manitoba or Minnesota
- 2002/03 Load Shape adjusted to Area’s year 2005/06 forecast expected and extreme assumptions
- 2003/04 Load Shape adjusted to Area’s year 2005/06 forecast expected and extreme assumptions

MAAC
- 2002 Load shape adjusted to the 2005/06 forecast provided by PJM
- Load forecast uncertainty of +/- 4.6%, 9.2%, and 13.8%

ECAR
- 2002 Load Shape adjusted to the 2005/06 NERC ES&D forecast
- Load forecast uncertainty of +/- 3%, 7%, and 9%
- Operating Reserve 5% of load (30-min 1.7%; 10-min 3.3%)

Ontario
- Maintenance extended on two units (~ 750 MW reduction)
- 34 MW dispatchable demand participation does not materialize at the time of the winter peak
- Gas fired generation capability reduced (~ 500 MW reduction)
- 10% lower hydroelectric energy assumed

New England
- 8,700 MW of gas-only fired generation unavailable
- Increase firm capacity sales to New York (from 640 MW to 900 MW)

New York
- Flat Rock and Poletti in-service delayed (~ 542 MW reduction)

Québec
- Saint Marguerite 3 repairs yield less than anticipated (~ 124 MW)
- Maintenance extended (through January) on two units (~ 443 MW)

30 NERC’s Electricity and Supply Database (ES&D) available at: http://www.nerc.com/~esd/
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 less than one occurrence for the NPCC Areas during the 2005/06 winter period for the expected load level under the Base and Severe Case conditions. The expected load level results were based on the probability-weighted average of the seven load levels simulated.

If reductions in anticipated resources and/or additional transmission limitations into NPCC materialize coincident with higher than expected loads, the Québec, Ontario, New England and the Maritimes Areas are expected to use these operating procedures under extreme load level conditions (representing the second to highest load level, having approximately a 6% chance of being exceeded).

In order to assess New England’s dependence on various fuels used for bulk power generation, ISO-NE has conducted numerous studies on the availability of fuels and how potential shortages could impact the overall reliability of the electric system. In addition, studies on the constraints on natural gas and dual-fueled (oil and gas capability) units have been completed.

In addition to the studies completed, the impact of Hurricanes Katrina and Rita on Gulf Coast energy production has limited the exploration, production and refining capacity of the oil and gas supply from that region. In order to assess the extent of this situation, ISO-NE initiated a study with Levitan and Associates, Inc.\textsuperscript{31} to assess the potential impact of Hurricanes Katrina and Rita on the coming winter.

Several conclusions of the study were reached including:

- This winter, a significant amount of natural gas production may not be available to interstate pipelines serving the Atlantic seaboard. Consequently, natural gas and wholesale electricity prices will remain high throughout the heating season.
- New England has diverse natural gas supplies, including strong pipeline connections with Canada and imported liquefied natural gas (LNG). However, the region depends on two major interstate pipelines to bring in Gulf Coast natural gas. To the extent supply or delivery constraints arise, most of the region’s gas-fired power plants could be adversely affected as a result of the “non-firm” character of their gas supply and transportation services.
- ISO New England can mitigate this winter’s natural gas situation in part by increased use of oil-fired power plants. Supplies of fuel oil available to power plants and storage facilities accessible by barge or tanker ships are likely to be adequate for the winter. However, harsh winter weather could pose logistical challenges for truck-transported fuel oil shipments to some power plants, thereby affecting the reliability of fuel deliveries.

Commercial demand reduction, such as demand response as well as residential energy efficiency and conservation initiatives, will also play an integral part in ensuring the reliability of the region’s bulk power system for the 2005-2006 heating season.

In response to the findings of the Levitan Report, and in order to address the possibility that severe cold weather conditions this winter may exacerbate fuel supply and pricing issues for New England generating Resources, ISO-NE developed a contingency plan for this winter (the “Winter 2005/2006 Action Plan”). The Winter 2005/2006 Action Plan includes the following objectives:

- Communicating the need to reduce consumption in all hours to conserve fuel;
- Encouraging the utilization of dual-fuel generating capability;
- Expanding demand-side management programs in New England in order to help maintain needed Operating Reserves; and,
- Developing Emergency Energy procedures and Market Rules to complement the cold weather procedures set forth in Appendix H of Market Rule 1 to maintain reliability this winter during cold weather conditions.

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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 2005 – 2006 winter period under Base Case and Severe Case assumptions, and summarize the range of results for the winter and shoulder season months (the period from November 2005 to March 2006).

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 years 2005 and 2006, 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 December 1, 2005. The assessment will:

   1. Review previous Area winter season’s actual 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. Incorporate, as appropriate, the reliability impacts that the evolving market rules may have on the assumptions.
### Table 7(a) - Base Case Assumptions (2002/03 Load Shape Assumption)

Expected Need for Indicated Operating Procedures (days/period)

(Occurrences 0.5 or greater are highlighted)

<table>
<thead>
<tr>
<th>Base Case</th>
<th>Quebec</th>
<th>Maritimes</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 Appeal</td>
<td>30-min VR</td>
<td>10-min Appeal</td>
<td>30-min VR</td>
</tr>
<tr>
<td>Nov</td>
<td>- - - -</td>
<td>- - - -</td>
<td>- - -</td>
<td>0.002</td>
<td>- -</td>
</tr>
<tr>
<td>Dec</td>
<td>0.002</td>
<td>- -</td>
<td>-</td>
<td>0.059</td>
<td>0.019</td>
</tr>
<tr>
<td>Jan</td>
<td>0.136</td>
<td>0.097</td>
<td>0.042</td>
<td>0.002</td>
<td>0.238</td>
</tr>
<tr>
<td>Feb</td>
<td>0.010</td>
<td>0.001</td>
<td>- -</td>
<td>0.106</td>
<td>0.031</td>
</tr>
<tr>
<td>Mar</td>
<td>- - -</td>
<td>-</td>
<td>0.003</td>
<td>0.001</td>
<td>-</td>
</tr>
<tr>
<td>Nov-Mar</td>
<td>0.148</td>
<td>0.098</td>
<td>0.042</td>
<td>0.002</td>
<td>0.406</td>
</tr>
<tr>
<td>02/03 Load Shape-Expected Load</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Nov</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>0.002</td>
<td>0.005</td>
</tr>
<tr>
<td>Dec</td>
<td>0.021</td>
<td>-</td>
<td>-</td>
<td>0.866</td>
<td>0.192</td>
</tr>
<tr>
<td>Jan</td>
<td>2.005</td>
<td>1.450</td>
<td>0.618</td>
<td>0.023</td>
<td>2.658</td>
</tr>
<tr>
<td>Feb</td>
<td>0.142</td>
<td>0.012</td>
<td>0.001</td>
<td>-</td>
<td>1.158</td>
</tr>
<tr>
<td>Mar</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>0.036</td>
<td>0.010</td>
</tr>
<tr>
<td>Nov-Mar</td>
<td>2.168</td>
<td>1.462</td>
<td>0.619</td>
<td>0.023</td>
<td>4.540</td>
</tr>
</tbody>
</table>

Notes:
- "30-min" - reduce 30-minute Reserve Requirement; "VR" - and initiate Voltage Reduction (Interruptible Loads for the Maritimes Area);
- "10-min" - and reduce 10-minute Reserve Requirement; "Appeal" - and initiate General Public Appeals; "Disc" - and disconnect customer load.
# APPENDIX B

## Table 7(b) - Base Case Assumptions (2003/04 Load Shape Assumption)

Expected Need for Indicated Operating Procedures (days/period)

(Occurrences 0.5 or greater are highlighted)

<table>
<thead>
<tr>
<th>Base Case</th>
<th>Quebec</th>
<th>Maritimes Area</th>
<th>New England</th>
<th>New York</th>
<th>Ontario</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>30-min</td>
<td>10-min</td>
<td>Appeal /Disc</td>
<td>30-min</td>
<td>10-min</td>
</tr>
<tr>
<td>03/04 Load Shape-Expected Load</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Nov</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>Dec</td>
<td>0.002</td>
<td>-</td>
<td>-</td>
<td>0.258</td>
<td>0.083</td>
</tr>
<tr>
<td>Jan</td>
<td>0.266</td>
<td>0.097</td>
<td>0.034 0.001</td>
<td>0.208</td>
<td>0.047</td>
</tr>
<tr>
<td>Feb</td>
<td>0.003</td>
<td>-</td>
<td>-</td>
<td>0.110</td>
<td>0.030</td>
</tr>
<tr>
<td>Mar</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>0.002</td>
<td>-</td>
</tr>
<tr>
<td>Nov-Mar</td>
<td>0.271</td>
<td>0.097</td>
<td>0.034 0.001</td>
<td>0.578</td>
<td>0.160</td>
</tr>
<tr>
<td>03/04 Load Shape-Extreme Load</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Nov</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>0.003</td>
<td>-</td>
</tr>
<tr>
<td>Dec</td>
<td>0.026</td>
<td>-</td>
<td>-</td>
<td>2.660</td>
<td>0.002</td>
</tr>
<tr>
<td>Jan</td>
<td>3.046</td>
<td>1.435</td>
<td>0.501 0.013</td>
<td>2.707</td>
<td>0.549</td>
</tr>
<tr>
<td>Feb</td>
<td>0.042</td>
<td>0.001</td>
<td>-</td>
<td>1.352</td>
<td>0.368</td>
</tr>
<tr>
<td>Mar</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>0.022</td>
<td>0.005</td>
</tr>
<tr>
<td>Nov-Mar</td>
<td>4.014</td>
<td>1.436</td>
<td>0.501 0.013</td>
<td>6.744</td>
<td>1.824</td>
</tr>
</tbody>
</table>

Notes:  "30-min" - reduce 30-minute Reserve Requirement; "VR" - and initiate Voltage Reduction (Interruptible Loads for the Maritimes Area); "10-min" - and reduce 10-minute Reserve Requirement; "Appeal" - and initiate General Public Appeals; "Disc" - and disconnect customer load.
### Table 8(a) - Severe Case Scenario (2002/03 Load Shape Assumption)
- Expected Need for Indicated Operating Procedures (days/period)

(Occurrences 0.5 or greater are highlighted)

<table>
<thead>
<tr>
<th>Severe Case Results</th>
<th>Quebec</th>
<th>Maritimes</th>
<th>New England</th>
<th>New York</th>
<th>Ontario</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>30-min</td>
<td>10-min</td>
<td>Apl</td>
<td>Disc</td>
<td></td>
</tr>
<tr>
<td>02/03 Load Shape-Expected Load</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Nov</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>Dec</td>
<td>0.024</td>
<td>0.003</td>
<td>-</td>
<td>0.103</td>
<td>0.027</td>
</tr>
<tr>
<td>Jan</td>
<td>0.267</td>
<td>0.144</td>
<td>0.128</td>
<td>0.022</td>
<td>0.022</td>
</tr>
<tr>
<td>Feb</td>
<td>0.047</td>
<td>0.011</td>
<td>0.002</td>
<td>-</td>
<td>0.017</td>
</tr>
<tr>
<td>Mar</td>
<td>0.006</td>
<td>-</td>
<td>-</td>
<td>0.009</td>
<td>0.001</td>
</tr>
<tr>
<td>Nov-Mar</td>
<td>0.344</td>
<td>0.158</td>
<td>0.130</td>
<td>0.022</td>
<td>0.581</td>
</tr>
<tr>
<td>02/03 Load ShapeExtreme Load</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Nov</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>Dec</td>
<td>0.300</td>
<td>0.027</td>
<td>0.002</td>
<td>-</td>
<td>1.252</td>
</tr>
<tr>
<td>Jan</td>
<td>2.327</td>
<td>2.015</td>
<td>1.891</td>
<td>0.300</td>
<td>0.299</td>
</tr>
<tr>
<td>Feb</td>
<td>0.662</td>
<td>0.121</td>
<td>0.014</td>
<td>-</td>
<td>1.960</td>
</tr>
<tr>
<td>Mar</td>
<td>0.080</td>
<td>0.003</td>
<td>-</td>
<td>-</td>
<td>0.114</td>
</tr>
<tr>
<td>Nov-Mar</td>
<td>3.369</td>
<td>2.166</td>
<td>1.907</td>
<td>0.300</td>
<td>0.299</td>
</tr>
</tbody>
</table>

Notes: "30-min" - reduce 30-minute Reserve Requirement; "VR" - and initiate Voltage Reduction (Interruptible Loads for the Maritimes Area); "10-min" - and reduce 10-minute Reserve Requirement; "Apl" - and initiate General Public Appeals; "Disc" - and disconnect customer load.
### APPENDIX B

**Table 8(b) - Severe Case Scenario (2003/04 Load Shape Assumption)**

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

(Occurrences 0.5 or greater are highlighted)

<table>
<thead>
<tr>
<th>Severe Case Results</th>
<th>Quebec</th>
<th>Maritimes Ar Ea</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 Appeal Disc</td>
<td>30-min VR</td>
<td>10-min Appeal Disc</td>
<td>30-min VR</td>
</tr>
<tr>
<td>Nov-Mar</td>
<td>0.624 0.269 0.158 0.014</td>
<td>0.807 0.201 0.001</td>
<td>0.947 0.328 0.169 0.022 0.022</td>
<td>- - - -</td>
<td>0.226 0.067 0.016 0.001</td>
</tr>
<tr>
<td>03/04 Load Shape-Expected Load</td>
<td>0.624 0.269 0.158 0.014</td>
<td>0.807 0.201 0.001</td>
<td>0.947 0.328 0.169 0.022 0.022</td>
<td>- - - -</td>
<td>0.226 0.067 0.016 0.001</td>
</tr>
</tbody>
</table>

**Notes:**
- "30-min" - reduce 30-minute Reserve Requirement; "VR" - and initiate Voltage Reduction (Interruptible Loads for the Maritimes Area);
- "10-min" - and reduce 10-minute Reserve Requirement; "Appeal" - and initiate General Public Appeals; "Disc" - and disconnect customer load.
Multi-Area Reliability Simulation Program Description

General Electric’s Multi-Area Reliability Simulation (MARS) program 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:

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

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 curtable. 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. Curtable 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.