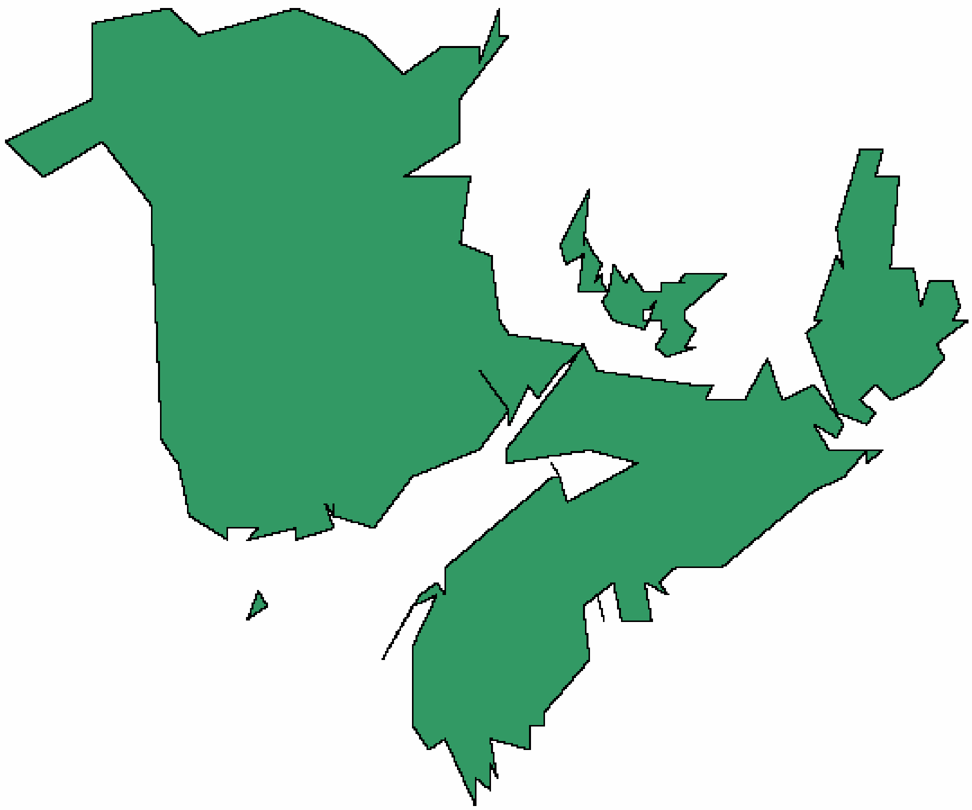
NPCC
MARITIMES AREA
TRIENNIAL REVIEW OF RESOURCE ADEQUACY



NEW BRUNSWICK SYSTEM OPERATOR
NOVA SCOTIA POWER INCORPORATED
MARITIME ELECTRIC COMPANY LIMITED
NORTHERN MAINE ISA, INC.

Approved by the RCC on March 9, 2005

December 2004

1.0 EXECUTIVE SUMMARY

The 2004 Maritimes Area Triennial Review of Resource Adequacy, covering the period January 2005 through December 2009, is the sixth such submission to the Northeast Power Coordinating Council (NPCC). The previous Triennial Review was approved in December 2001. The Maritimes Area is a winter peaking area that includes the New Brunswick System Operator (NBSO), Nova Scotia Power Inc. (NS Power), Maritime Electric Company Ltd. (MECL), and the Northern Maine Independent System Administrator, Inc (NMISA). MECL supplies the province of Prince Edward Island.

This Triennial Review replaces New Brunswick Power Corporation (NB Power) with the New Brunswick System Operator (NBSO). This change occurred due to the proclamation of New Brunswick’s new Electricity Act on Oct. 1, 2004.

The model for this Triennial Review has been adjusted to include the generation and load information of NMISA, whereas in previous reviews the NMISA system was not specifically included in the model. In previous Triennial Reviews, the impact of the NMISA system was accounted for through a projection of firm sales from New Brunswick to Northern Maine. This change in the model was made for the purpose of improving accuracy. The NMISA system is now modeled the same as the NBSO, NS Power, and MECL systems.

This Triennial Review includes an analysis of the capability of sub-areas within the Maritimes Area to meet the NPCC reliability criterion without exceeding inter-area transmission capacity limits. This analysis was not performed in previous Triennial Reviews, but it is now included to comply with the 2004 NPCC resource adequacy planning criteria.

The Maritimes Area’s combined load forecast for this review consists of the NBSO, NS Power, MECL, and NMISA 2004 forecasts. The coincident peak forecast for 2005 is 5561 MW. The 2005 forecast for NBSO, NS Power, and MECL is 5421 MW, which is 111 MW more than the forecasted peak for 2005 used in the 2001 review. The average annual growth in demand over the study period of this review is 1.49%.

The reserve criterion for the Maritimes Area is 20%, and adherence to this criterion is demonstrated to comply with the NPCC reliability criterion. For the base load forecast, the expected number of firm load disconnections for the period 2005 through 2009 varies from a low of 0.002 to a high of 0.137 days/year. Further, assuming load forecast uncertainty (LFU), the expected number of firm load disconnections from 2005 through 2009 varies from a low of 0.006 to a high of 0.380 days per year. The NPCC reliability criterion of less than 0.1 days of firm load disconnections per year is not exceeded by the Maritimes Area in years 2005 through 2008, but it is exceeded in 2009 due to the planned refurbishment of the 635 MW Point Lepreau nuclear facility in New Brunswick. This planned refurbishment is awaiting the approval of the New Brunswick government, and arrangements for replacement capacity to accommodate the refurbishment plan have not been made to date.

Construction of a second tie between New Brunswick and New England is expected to begin in the Fall of 2005, with a planned in-service date of Fall of 2006. This second tie increases the import capability of the Maritimes Area from 1200 MW to 1500 MW. The export capability from New Brunswick to New England will be increased by 300 MW.

The Maritimes Area requires no support from interconnections in 2005 through 2008 to meet the NPCC reliability criterion. In 2009, the required interconnection assistance is 240 MW in order to meet the NPCC criterion. This represents 16% of the 1500 MW of available support from interconnections to the Maritimes Area in 2009.

Table 1

Summary of Major Assumptions and Results

<table>
<tr><th colspan="4">MAJOR ASSUMPTIONS</th></tr>
<tr><td>Load Forecast</td><td colspan="3">NBSO 2004
NS Power 2004
MECL 2004
NMISA 2004</td></tr>
<tr><td>Resource Adequacy Criterion</td><td colspan="3">0.1 days/year</td></tr>
<tr><td>Maritimes Required Reserve</td><td colspan="3">20%</td></tr>
<tr><td rowspan="4">Inter-Area Transmission Capacity Limits</td><td>Path</td><td>Export Limit (MW)</td><td>Import Limit (MW)</td></tr>
<tr><td>NBSO to NS Power</td><td>350</td><td>300</td></tr>
<tr><td>NBSO to MECL</td><td>222</td><td>222</td></tr>
<tr><td>NBSO to NMISA</td><td>100</td><td>90</td></tr>
<tr><td>Maritimes Unit Data</td><td colspan="3">Appendix A – Table A-2 (by utility)</td></tr>
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<table>
<tr><th colspan="3">RESULTS</th></tr>
<tr><th>Year</th><th>Expected Number of Firm Load Disconnections
Days/year</th><th>Required Interconnection Support
MW</th></tr>
<tr><td>Base Load Forecast</td><td></td><td></td></tr>
<tr><td>2005</td><td>0.002</td><td>0</td></tr>
<tr><td>2006</td><td>0.002</td><td>0</td></tr>
<tr><td>2007</td><td>0.003</td><td>0</td></tr>
<tr><td>2008</td><td>0.010</td><td>0</td></tr>
<tr><td>2009</td><td>0.137</td><td>50</td></tr>
<tr><td>Base Load Forecast Including LFU</td><td></td><td></td></tr>
<tr><td>2005</td><td>0.006</td><td>0</td></tr>
<tr><td>2006</td><td>0.010</td><td>0</td></tr>
<tr><td>2007</td><td>0.012</td><td>0</td></tr>
<tr><td>2008</td><td>0.047</td><td>0</td></tr>
<tr><td>2009</td><td>0.380</td><td>240</td></tr>
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Note: The expected number of firm load disconnections for the Base Load Forecast including LFU is based on the procedure described in Section 4.5.

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3.0 INTRODUCTION

The Maritimes Area Triennial Review of Resource Adequacy, covering the period January 2005 through December 2009, is the sixth such submission to the Northeast Power Coordinating Council (NPCC). The previous Triennial Review was approved in December 2001. The Maritimes Area is a winter peaking area that includes the New Brunswick System Operator (NBSO), Nova Scotia Power Inc. (NS Power), Maritime Electric Company Ltd. (MECL), and the Northern Maine Independent System Administrator, Inc (NMISA). MECL supplies the province of Prince Edward Island.

On October 1, 2004 the proclamation of New Brunswick's new Electricity Act created a new corporation called the New Brunswick System Operator (NBSO). The NBSO is a not-for-profit, independent body whose primary responsibility is to ensure the security and reliability of the electricity system and to facilitate the development and operation of a competitive electricity market. Whereas past reviews referred to NB Power, this review refers to the NBSO.

The model for this Triennial Review has been adjusted to include the generation and load information of NMISA. In previous Triennial Reviews, the impact of the NMISA system had been indirectly accounted for through a projection of firm sales from New Brunswick to Northern Maine. This change of the model was made for the purpose of improving accuracy.

This Triennial Review includes an analysis of the capability of sub-areas within the Maritimes Area to meet the NPCC reliability criterion without exceeding inter-area transmission limits. This analysis was not performed in previous Triennial Reviews, but it is now included to comply with the 2004 NPCC resource adequacy planning criteria.

The load forecast data in the 2001 review was based on the NS Power and MECL 2000 forecasts and the NB Power 2001 load forecast. In the current review, the Maritimes Area combined load forecast consists of the 2004 load forecasts for NBSO, NS Power, MECL, and NMISA. For the present review, the forecast coincident peak of 5561 MW for 2005 is 111 MW higher[†] than the forecast peak for 2005 in the 2001 review. The current review also forecasts the 2006 peak to be 141 MW higher[††] than the forecast of the 2006 peak in the 2001 review.

[†] The difference between the 2005 forecasts of the current review and the 2001 review was calculated with the NMISA peak subtracted out from the current review, as NMISA was not included as a part of the Maritimes Area in the 2001 review.

[††] The difference between the 2006 forecasts of the current review and the 2001 review was calculated with the NMISA peak subtracted out from the current review, and 165 MW of forecast industrial self-generation added to the 2001 review.

Higher forecast numbers in the current review are mainly due to a lower than expected availability of natural gas for customers in the Maritimes Area.

A capacity reserve criterion for the Maritimes Area is described and adherence to this criterion is demonstrated. Further, this reserve capacity criterion is shown to comply with the NPCC reliability criterion.

Table 2

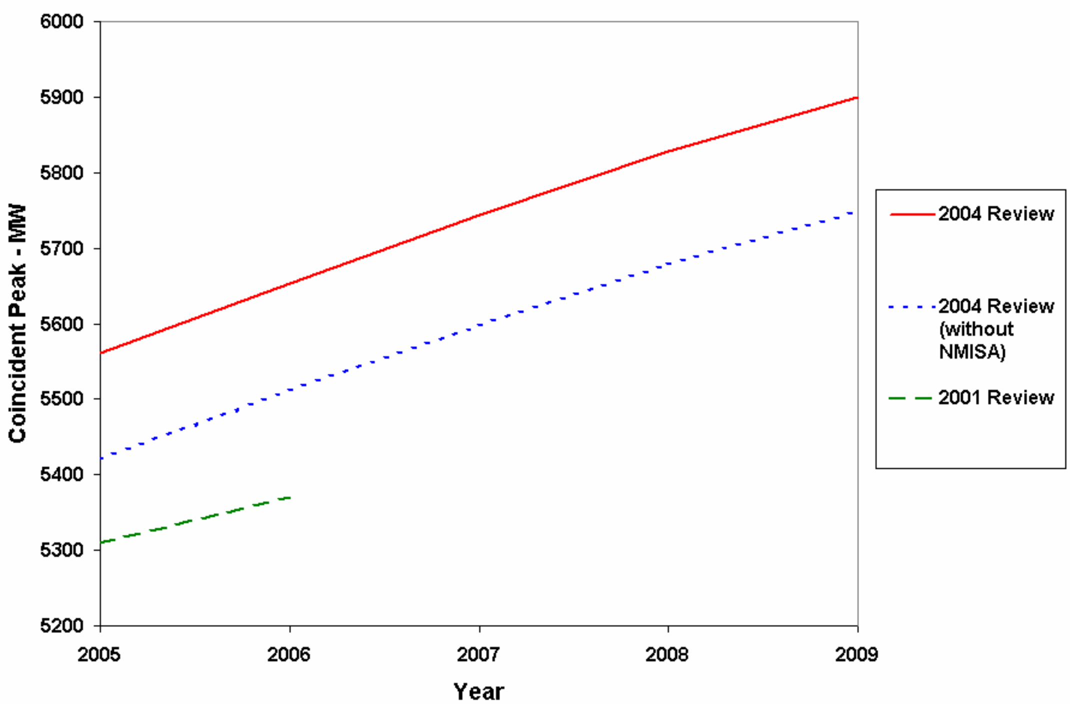
Comparison of Load Forecasts

Winter Peak (Month of February)	2004 Review MW	2004 NMISA MW	2004 Review (without NMISA) MW	2001 Review MW
2005	5561	140	5421	5310
2006	5654	143	5511	5370†
2007	5744	146	5598	N/A
2008	5828	149	5679	N/A
2009	5900	152	5748	N/A
Average Annual Compound Growth Rate				
Five Year Period	**2005 - 2009**	**2005 - 2009**	**2005 - 2009**	**2002-2006**
Growth Rate	1.49%	2.08%	1.48%	1.13%

† This value includes 165 MW of load that was to be supplied by industrial self-generation.

Figure 1

Comparison of Load Forecasts



4.0 RESOURCE ADEQUACY CRITERION

4.1 Statement of Resource Adequacy Criterion

NBSO, NS Power, and MECL individually apply a capacity based criterion in determining their required reserve. NMISA does not apply a capacity based criterion beyond the NPCC reliability criterion.

NBSO and NS Power each require a reserve equal to the largest unit or 20% of the firm load, and MECL requires a reserve equal to 15% of the firm system load. The Maritimes Area as a whole was assumed to have the same criterion as NB Power and NS Power. This simplification has negligible effects on the results because of the size of MECL and NMISA relative to NBSO and NS Power combined. Thermal and hydro generators are considered available at the Demonstrated Maximum Net Capability (DMNC) in the determination of the reserve margin.

The NPCC Generation Reliability criterion states:

Each Area's probability (or risk) of disconnecting any firm load due to resource deficiencies shall be, on average, not more than once in ten years. Compliance with this criteria shall be evaluated probabilistically, such that the loss of load expectation [LOLE] of disconnecting firm load due to resource deficiencies shall be, on average, no more than 0.1 day per year. This evaluation shall make due allowance for demand uncertainty, scheduled outages and deratings, forced outages and deratings, assistance over interconnections with neighboring Areas and Regions, transmission transfer capabilities, and capacity and/or load relief from available operating procedures.

In effect, this criterion is applied as less than 0.1 days of firm load disconnections per year.

4.2 Emergency Operating Procedures

Although this document presents a review of resource adequacy for the interconnected Maritimes Area, each separate system remains under the exclusive control of its utility for purposes of economic dispatch. For reliability purposes, however, reserve sharing agreements do exist and the systems operate as an Area in accordance with NPCC criteria and guidelines.

The particular actions taken by the Energy Coordinator/Dispatcher when faced with a developing or sudden capacity shortage are based upon the assessment of which of a number of possible actions are best suited to the prevailing system conditions. The actions initiated are based upon previous experience in dealing with similar situations and, if the situation permits, usually after consultation with other System Operations personnel similarly experienced in this regard. In practice, the corrective actions that are taken are one or more of the following Emergency Operation Procedures (EOP):

1. Synchronize and load all available hydro units.

2. Bring on-line units up to their DMNC.

3. Cancel economy and other external interruptible sales.

4. Begin start-up procedures for “cold-standby” thermal units.

5. Synchronize and load combustion turbines.

6. Purchase capacity from Hydro-Quebec.

7. Purchase capacity from New England.

8. Cut interruptible sales to industrial customers.

9. Maximize MVAR support (capacitor banks, synchronous condensers) if capacity shortage is causing a low voltage condition in a particular area.

10. Implement a 5% voltage reduction at selected substations within Nova Scotia (20-60 MW)

11. Load up thermal units to emergency ratings. (40 MW)

12. Appeal to the public for voluntary customer load reduction.

13. Disconnect customer loads as necessary to correct either a local or widespread problem.

Some or all of the above steps may be used in varying sequence to meet a capacity shortage depending on the generation pattern in effect at the time and whether or not the shortage results in localized internal system problems.

Although steps 10 through 12 are valid, the level of assistance available from these procedures is not modeled in this study.

4.3 Maritimes Area Required Reserve

The Area employs a reserve criterion of 20% of firm load with the understanding that the interconnection assistance is potentially available if required. The required installed reserve is shown in Section 5.0.

4.4 Relationship of Reserve Criterion to NPCC Reliability Criterion

In order to relate the Maritimes Area reserve criterion to the NPCC resource adequacy criterion as stated in Section 4.1, it is necessary to evaluate the system at a time when it just meets the reserve criterion. The Maritimes Area is projected to have a reserve margin greater than 20% for years 2005-08. The projected reserve margin for 2009 is only 14.6%. It was therefore necessary to scale the load in order to achieve a reserve margin of 20% for a comparison evaluation.

The evaluation shows that for the Maritimes Area, isolated from all other systems, a reserve of 20% corresponds to an expected number of firm load disconnections of approximately 0.1310 days/year with LFU.

The NPCC criterion of 0.1 days/year expected number of customer disconnections as stated in Section 4.1 allows for the inclusion of the effects of interconnections.

When the Maritimes Area has a reserve of 20% with the interruptible load removed, approximately 50 MW of interconnection assistance is required in order to meet the NPCC criterion. This represents 4.2% of the normal import capabilities with Quebec (1100 MW) and New England (100 MW). In addition, NB Power is supplying 200 MW of system peaking capacity to Hydro Quebec tied to the availability of the Millbank combustion turbine (CT) units. Two of the Millbank CT's have not been included in this study to account for this capacity export. However, this arrangement has the effect of increasing the total interconnection capability between Hydro Quebec and New Brunswick by an additional 200 MW. The 2004 NPCC CP-8 Working Group report "Review of Interconnection Assistance Reliability Benefits" concluded that the amount of interconnection assistance available to the Maritimes Area in 2006 was 1200 MW. The interconnection assistance available to the Maritimes will increase by 300 MW with the construction of a second tie between New Brunswick and New England. Construction of the second tie is scheduled to begin in the Fall of 2005 with an in-service date of Fall of 2006.

As a result of the preceding, it is concluded that the reserve criterion of the Maritimes Area meets the NPCC Resource Adequacy Criterion.

4.5 Recent Reliability Studies

NBSO, NS Power, MECL, and NMISA individually conduct internal reviews of their capacity requirements by comparison of generation sources with forecast loads according to the reserve criteria described previously.

The results presented in this review are based upon an evaluation conducted during the fourth quarter of 2004 for the period 2005 through 2009.

Table 3 and Figure 2 illustrate that the Maritimes Area system can achieve the NPCC criterion for expected number of customer disconnections of 0.1 days/year for 2005 through 2008 without the benefits arising from interconnection support from neighboring utilities. In 2009, the required interconnection assistance to meet the NPCC reliability criterion is 50 MW.

Table 3

Expected Number of Firm Load Disconnections - Base Load Forecast

Calendar Year	Expected Number Of Firm Load Disconnections Days/year	Required Interconnection Support MW
2005	0.002	0
2006	0.002	0
2007	0.003	0
2008	0.010	0
2009	0.137	50

The effect of load forecast uncertainty (LFU) was evaluated using a method similar to that described in the 1994 NPCC CP-5 report “Review of Interconnection Assistance Reliability Benefits”. An analysis of the historical load forecast of the Maritimes Area utilities has shown that the standard deviation of the load forecast errors is approximately 4.6% based upon the four year lead time required to add new resources. To incorporate LFU, two additional load models were created from the base load forecast by increasing it by 4.6 and 9.2 percent respectively. The reliability analysis was repeated for these two load models.

It is assumed that the forecast error is approximately normally distributed around the forecast value, and that the contribution to system LOLE is negligible when loads are less than the forecast value by more than ½ standard deviation. This results in weighting factors of 0.383, 0.242, and 0.067 for the three results obtained using the base, 4.6 percent increased, and 9.2 percent increased load models respectively.

The results of the LFU evaluation as indicated in Table 4 and Figure 2 demonstrate that the Maritimes Area system can still achieve the NPCC criterion of 0.1 days/year without interconnection assistance in the period 2005 through 2008. In 2009, the required interconnection assistance is 240 MW in order to meet the NPCC reliability criterion. This represents 16% of the 1500 MW of available support from interconnections to the Maritimes Area in 2009.

The results of the LFU analysis are intended as a sensitivity analysis. If higher than forecast loads occur, then the Maritimes Area has contingency plans (see Section 5.3) that may be implemented.

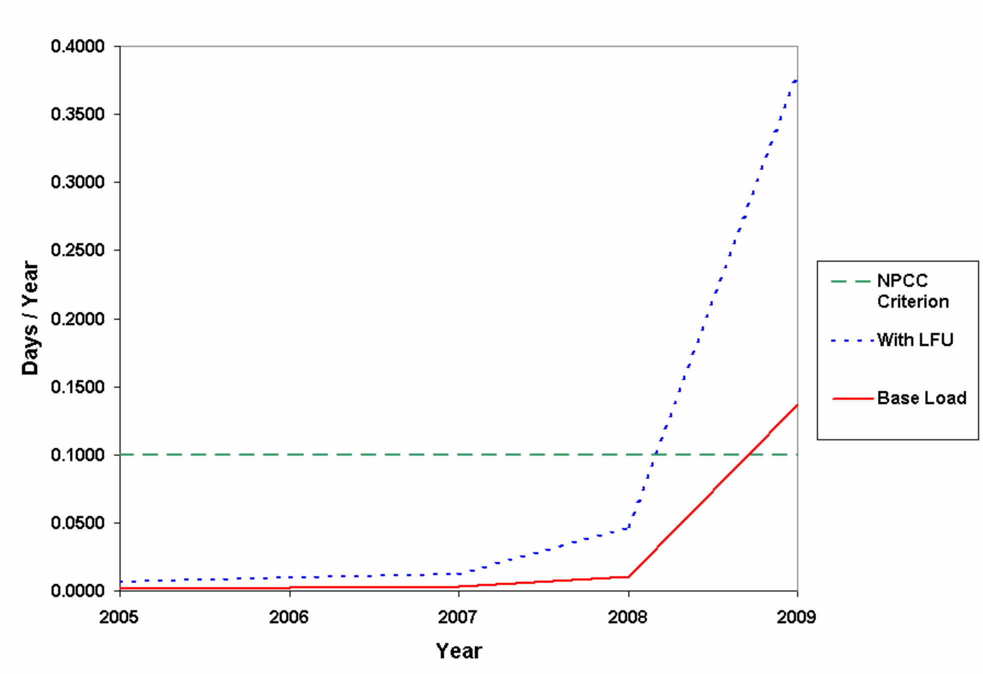
Table 4

Expected Number of Firm Load Disconnections - Load Forecast Uncertainty

Calendar Year	Expected Number Of Firm Load Disconnections Days/year	Required Interconnection Support MW
2005	0.006	0
2006	0.010	0
2007	0.012	0
2008	0.047	0
2009	0.380	240

Figure 2

Expected Number of Firm Load Disconnections

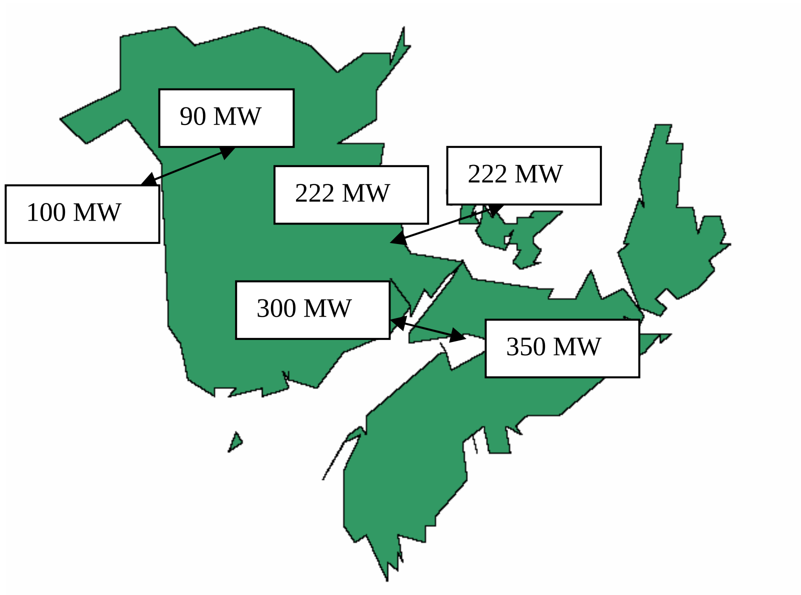


4.6 Inter-area Transmission Capacity Limits

Within the Maritimes Area, the areas of Nova Scotia, PEI, and Northern Maine are radially connected to New Brunswick as per Figure 3. Of these three interconnections, only between New Brunswick and Nova Scotia is transmission congestion an issue. PEI does not have enough installed generation (110 MW in 2005) nor firm peak load (217 MW in 2005) to exceed the interconnection rating to New Brunswick of 222 MW. Northern Maine does not have enough installed capacity (141 MW in 2005) to generate an amount greater than the sum of the local load and the interconnection export rating (at least 160 MW). While it is possible that Northern Maine may eventually require more than 100 MW of interconnection support from New Brunswick to meet the NPCC reliability criterion, there are plans in Northern Maine designed to address that situation. These plans include increasing generation above that included in this analysis, deferring retirements of units beyond 2006, or increasing the interconnection import capability with New Brunswick. Because of these possible actions, no detailed modeling of the New Brunswick to Northern Maine interface was completed in this review.

Figure 3

Inter-Area Transmission Capacity Limits



To evaluate whether the Maritimes Area could meet the NPCC reliability criterion without exceeding inter-area transmission capability limits, the system was split into two sub-areas, one on each side of the New Brunswick to Nova Scotia interconnection. This is the only interconnection within the Maritimes Area that is subject to congestion. The two sub-areas were then analyzed to see if each could meet the NPCC criteria without a capacity dependence on the other area that exceeded the transmission capability limit of the interconnection. The interconnection support available from one area to the other was also limited by the maximum capacity support that an area could provide without exceeding the NPCC reliability criterion. The results of the analysis for the NS Power area appear in Table 5.

Table 5

Expected Number of Firm Load Disconnections
NS Power Area Only

Calendar Year	Expected Number Of Firm Load Disconnections Days/year (with LFU)	Total Required Interconnection Support MW	Interconnection Support Available From NBSO Area MW	External Interconnection Support Required MW
2005	0.015	-90	0	0
2006	0.033	-55	0	0
2007	0.061	-25	0	0
2008	0.094	-5	0	0
2009	0.159	25	0	25

The results of Table 5 show that the NS Power area can meet the NPCC reliability criterion in years 2005-08 without requiring any support from its interconnection to New Brunswick. In 2009, the NS Power area requires 25 MW of interconnection support, which represents only 7.1% of the 350 MW import capability of its interconnection to New Brunswick. Negative results of the total required interconnection support represent MW amounts of capacity that the NS Power area can provide to the NBSO area without exceeding the NPCC reliability criterion.

The results of the analysis for the NBSO, MECL, and NMISA area appear in Table 6.

Table 6

Expected Number of Firm Load Disconnections
NBSO, MECL, and NMISA Area Only

Calendar Year	Expected Number Of Firm Load Disconnections Days/year (with LFU)	Total Required Interconnection Support MW	Interconnection Support Available From NS Power MW	External Interconnection Support Required MW
2005	0.181	90	90	0
2006	0.200	100	55	45
2007	0.273	150	25	125
2008	1.381	350	5	345
2009	3.648	510	-25	535

The results of Table 6 show that the area consisting of NBSO, MECL, and NMISA area requires support from its interconnections to meet the NPCC reliability criterion. The interconnection support from NS Power was limited by the reliability criterion applied to the NS Power area rather than the interconnection import capability of 300 MW. In 2009, the sum of external interconnection support required by the NS Power area and the NBSO, MECL, and NMISA area is 535 MW, which is still within the 1500 MW import capability of the Maritimes Area for 2009.

5.0 RESOURCE ADEQUACY ASSESSMENT

5.1 Comparison of Planned and Required Reserve

In the comparison of the planned and required reserve, the following definitions apply. The required reserve of 20% is the reserve criterion of the Maritimes Area. The planned reserve is the actual reserve that will occur for the load forecast and resource plan used in this study.

Table 7 and Figure 4 represent the results of the reserve comparison for the base load forecast. In each year of the analysis, the planned reserve varies from -290 to 608 MW greater than the required reserve. The Maritimes Area does not meet its planned reserve criterion of 20% in 2009, but there is sufficient lead time to permit the Maritimes Area to initiate appropriate actions as described in Section 5.3.

Table 7

Comparison of Planned and Required Reserve - Base Load Forecast

Month Of February	Installed Capacity MW	Forecast Coincident Peak MW	Interruptible Load MW	Planned Reserve		Required Reserve	
				MW	%	MW	%
2005	6664	5561	514	1617	32.0	1009	20.0
2006	6688	5654	516	1550	30.2	1028	20.0
2007	6734	5744	520	1510	28.9	1045	20.0
2008	6725	5828	531	1428	27.0	1059	20.0
2009	6147	5900	536	783	14.6	1073	20.0

5.2 Comparison of Planned and Required Reserve – High Load Growth

Table 8 and Figure 4 illustrate the changes in planned and required reserve if the annual growth rate is 1% higher than forecast (i.e. 2.49% per year versus 1.49% per year). The results show that the resource plan of the Maritimes Area is sufficient to maintain a reserve of 20% or greater through 2008, and a reserve of only 9.8% in 2009. This provides sufficient lead time to permit the Maritimes Area to initiate appropriate actions as described in the following section. The planned reserve varies annually from –573 to 608 MW greater than the required reserve.

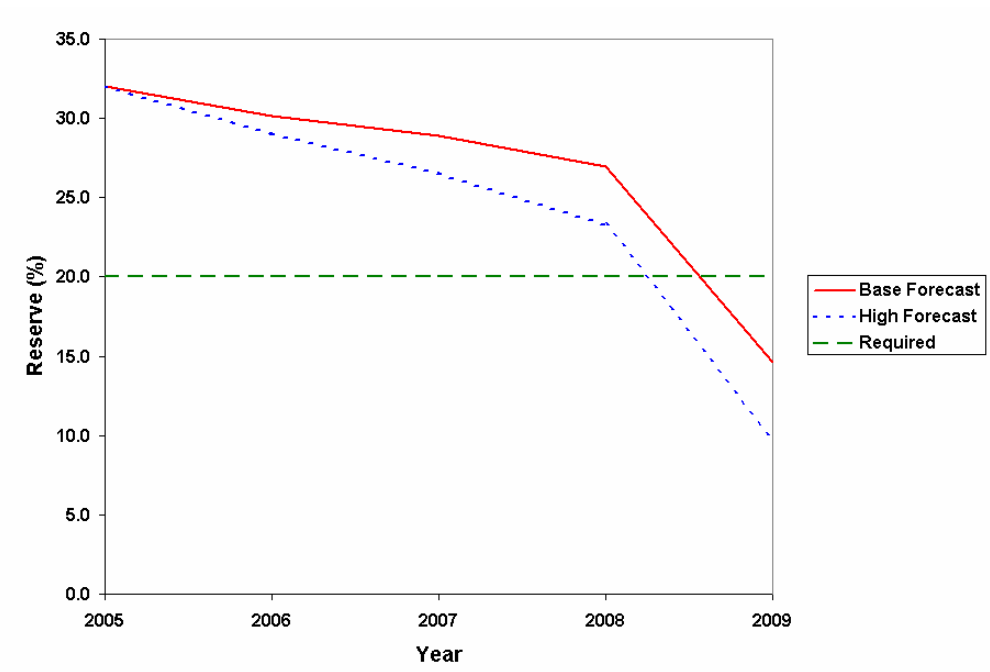
Table 8

Comparison of Planned and Required Reserve - High Load Growth

Month Of February	Installed Capacity MW	Forecast Coincident Peak MW	Interruptible Load MW	Planned Reserve		Required Reserve	
				MW	%	MW	%
2005	6664	5561	514	1617	32.0	1009	20.0
2006	6688	5699	516	1505	29.0	1037	20.0
2007	6734	5841	520	1413	26.5	1064	20.0
2008	6725	5987	531	1269	23.3	1091	20.0
2009	6147	6136	536	547	9.8	1120	20.0

Figure 4

Planned Versus Required Reserve



5.3 Contingency Plans

The Maritimes Area utilities forecast high and low load growth scenarios, and the impact of these forecasts on the utility generation scenarios are continually being evaluated in order to address load and resource uncertainties. In the event of a higher than expected growth in load, a number of options would be considered. These options include the purchases of capacity and/or energy, the advancement of base load generation additions, and the installation of combustion turbines.

6.0 PLANNED RESOURCE CAPACITY MIX

6.1 Planned Resource Capacity Mix

Table 9 and Figure 5 illustrate the planned resource capacity mix for the Maritimes Area. Appendix A, Section 1.2, Table A-2 presents a detailed list of all capacity resources for the Maritimes Area.

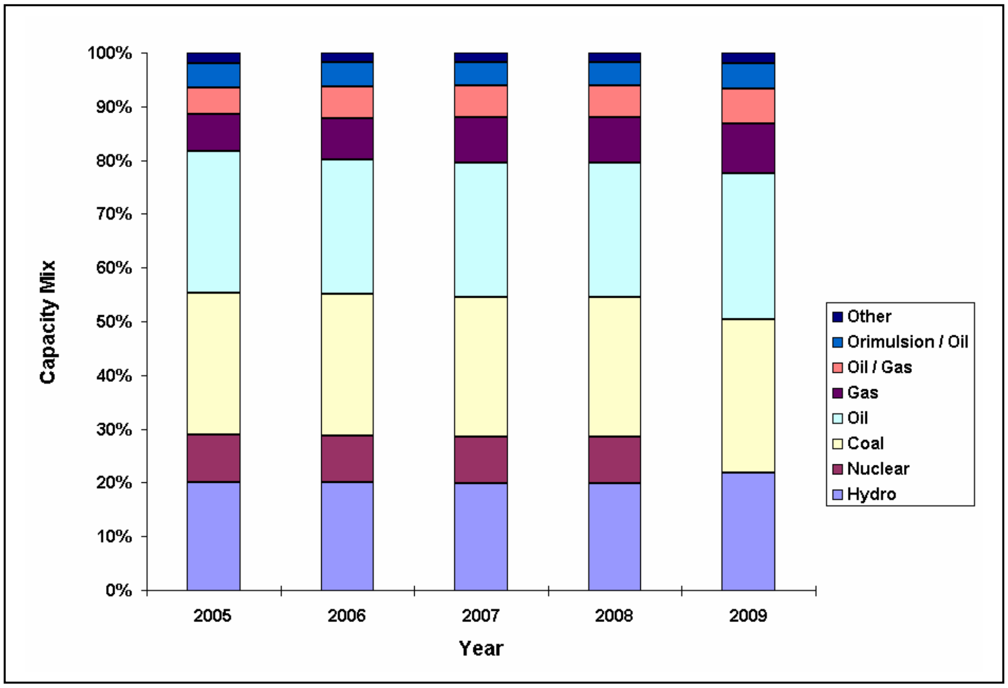
Table 9

Planned Resource Capacity Mix

Month Of February	Hydro %	Nuclear %	Coal %	Oil %	Gas %	Oil / Gas %	Orimulsion / Oil %	Other %
2005	20.1	8.9	26.4	26.4	6.8	4.9	4.5	2.0
2006	20.0	8.8	26.3	25.1	7.7	5.9	4.5	1.7
2007	19.9	8.6	26.1	24.9	8.4	5.9	4.5	1.7
2008	19.9	8.5	26.1	24.9	8.5	5.9	4.5	1.7
2009	21.8	0.0	28.6	27.2	9.3	6.4	4.9	1.9

Figure 5

Planned Resource Capacity Mix



6.2 Reliability Impact of Resource Diversification Strategy

As can be seen from Table 9 and the associated Figure 5, the Maritimes Area has a diversified mix of resources such that there is not a high degree of reliance upon any one type or source of fuel. As a result of this level of fuel type and resource diversification, there are no adverse reliability impacts resulting from this resource capacity mix, nor are there any environmental restrictions.

This level of diversification has been achieved by conversion of existing resources to utilize a different fuel (Dalhousie 1 and 2 from oil and coal, respectively, to Orimulsion®) or an additional fuel (Tufts Cove 1, 2, &3 to natural gas while retaining oil-fired capability). Dalhousie also has the capability to use oil, and this was put into use in the early months of 2003 when Orimulsion® shipments from Venezuela were halted due to a general strike.

The Maritimes Area is continuing its policy of fuel diversification with the conversion of 3 oil-fired units at Coleson Cove to burn Orimulsion® (while retaining oil-fired capability), the proposed conversion of 4 light-oil fired units at Burnside to natural gas (while retaining light oil-fired capability on units 1 and 3), and the proposed life extension of the Point Lepreau nuclear unit (refurbishment targeted for April 2008).

The Maritimes Area continues to see an increase in wind energy projects. PEI currently has 16.6 MW of wind capacity. NS Power expects to have 30 MW of wind capacity by the end of 2004, and has launched a call for projects for an additional 60 MW. New Brunswick and Northern Maine are expected to have 19.8 MW and 50 MW of wind capacity, respectively, by the end of 2005. While it is recognized that current and future wind projects will contribute to the Maritimes Area's ability to meet the NPCC reliability criterion, wind generation has not been included in this review due to the difficulty in modeling an intermittent generation project with a specific capacity value and a forced outage rate, especially for upcoming projects for which production levels are not known. As such, it is recognized that the results of this Triennial Review are conservative because they do not recognize the contribution of current and future wind projects in the Maritimes Area towards meeting the NPCC reliability criterion.

The Maritimes Area is also going to have increased capacity purchase capability as a result of a second interconnection with New England. Construction work on this second interconnection is scheduled to begin in the third quarter of 2005, and the anticipated in-service date is Fall of 2006. This new interconnection will increase the firm import capability to the Maritimes from New England by 300 MW.

APPENDIX A

DESCRIPTION OF RESOURCE RELIABILITY MODEL

DESCRIPTION OF RESOURCE RELIABILITY MODEL

1.0 Load Model

1.1 After reviewing historical hourly system load data of the Maritime utilities, it was determined that the 1999 system load data provided a typical Maritimes Area load shape. Demand and energy forecasts for 2005 to 2009 inclusive were prepared by each utility. The combined load forecast for the Maritimes Area is shown in Table A-1.

Table A - 1

Maritimes Area Load Forecast

COINCIDENT DEMAND MW													
Year	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**	**Peak**
2005	5361	5561	4853	4383	3958	3655	3575	3584	3599	4187	4569	5139	5561
2006	5447	5654	4927	4448	4024	3718	3640	3652	3653	4248	4648	5226	5654
2007	5532	5744	5002	4521	4090	3783	3701	3714	3719	4324	4724	5318	5744
2008	5618	5828	5098	4563	4134	3821	3740	3752	3757	4369	4770	5365	5828
2009	5679	5900	5121	4629	4198	3883	3803	3818	3815	4430	4839	5442	5900
ENERGY GWh													
Year	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**	**Total**
2005	3139	2855	2883	2512	2327	2144	2174	2208	2180	2422	2611	3065	30520
2006	3196	2903	2924	2553	2368	2184	2215	2254	2214	2463	2657	3116	31047
2007	3245	2948	2979	2596	2407	2223	2252	2293	2253	2505	2702	3170	31573
2008	3296	2992	3031	2609	2427	2240	2272	2311	2273	2529	2722	3193	31895
2009	3321	3018	2962	2651	2467	2280	2314	2353	2309	2563	2762	3239	32239
INTERRUPTIBLE DEMAND MW													
Year	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**	**On Peak**
2005	488	514	514	506	540	536	547	552	520	551	525	535	514
2006	489	516	515	505	540	538	554	561	522	552	526	537	516
2007	494	520	520	510	545	543	558	566	527	557	538	549	520
2008	505	531	531	519	554	552	568	575	536	568	542	553	531
2009	510	536	536	524	560	558	573	581	541	574	548	559	536

Note: The forecast coincident demand is higher in February than January due to the impact of historical curtailments of interruptible customers in January. These historical curtailments are also reflected in the interruptible demand forecast, where January interruptible demand is shown to have the lowest value for each year.

Load forecast uncertainty (LFU) was considered in the analysis as described in Section 4.5

1.3 Some entities within the Maritimes Area supply a portion of their own electricity demand and energy requirements. These entities are interconnected within the Maritimes Area and are not members of the Area. Only that portion of electricity demand and energy projections that is supplied by the Maritimes Area utilities is included in the area forecast.

1.4 The load forecast in Table A-1 includes the impact of DSM and efficiency programs.

2.0 Resource Unit Representation

Generating unit data for the four members of the Maritimes Area are presented in Table A-2. Table A-3 presents a summary of changes in resource data for the period 2005 - 2009 inclusive. The following sections document the tabulated data.

2.1 Unit Ratings

2.1.1 Definition

The generating unit capacity ratings represented in Table A-2 are the Demonstrated Maximum Net Capability (DMNC) winter ratings. These are evaluated periodically to establish each unit's sustained maximum net output over a two consecutive hour period.

2.1.2 Procedure for Verifying Ratings

Ratings of NBSO units are reviewed annually by the Generation Efficiency Section of the NB Power Generation (Conventional) Plant Operations Engineering Division in conjunction with System Operations. Data obtained from unit testing and from the generation reliability system is used in conducting these reviews. The Thermal Production Department at NS Power review unit capability ratings on an as-needed basis. As unit conditions change the impact on unit capability is assessed and, if required, a 2-hour test with the unit at full load is performed.

Table A - 2

Maritimes Area Resources

NBSO Resources				
Plant	**Unit**	**Type**	**Capacity MW**	**Notes**
Point Lepreau	1	Nuclear	594	Planned 18-month Refurbishment in April 2008
		Diesel	5	
Belledune	2	Coal	458	
Courtenay Bay	4	Oil	98	
Coleson Cove	1	Oil	326	
	2	Oil	326	
	3	Oil	326	
Dalhousie	1	Orimulsion® / Oil	97	
	2	Orimulsion® / Oil	203	
Bayside	6	Natural Gas	263	Capacity includes Combined Cycle Operation
Grand Lake	8	Coal	57	
Grand Manan	3	Diesel	28	
Millbank	1	Diesel	100	
	2	Diesel	100	
	3	Diesel	see note	Modeled as Tied to Sale Contract Until Nov 2011
	4	Diesel	see note	Modeled as Tied to Sale Contract Until Nov 2011
Ste Rose	1	Diesel	100	
IOL Cogen		Natural Gas	90	
NUG Purchases		Biomass	49	
Mactaquac	1	Hydro	110	
	2	Hydro	110	
	3	Hydro	110	
	4	Hydro	116	
	5	Hydro	113	
	6	Hydro	113	
Beechwood	1	Hydro	36	
	2	Hydro	36	
	3	Hydro	41	
Grand Falls	1	Hydro	16	
	2	Hydro	16	
	3	Hydro	16	
	4	Hydro	16	
Tobique	1	Hydro	10	
	2	Hydro	10	
Sisson	1	Hydro	9	
Milltown	1	Hydro	4	
TOTAL CAPACITY			**4102**	Total Capacity as of January 2005

Table A – 2 Maritimes Area Resources (cont'd)

NS Power Resources				
Plant	**Unit**	**Type**	**Capacity (MW)**	**Notes**
Tufts Cove	1	Gas/Oil	81	
	2	Gas/Oil	95	
	3	Gas/Oil	153	
	4	Natural Gas	49	Summer Capacity = 47 MW
	5	Natural Gas	49	Summer capacity = 47 MW
Lingan	1	Coal	153	Summer Capacity = 145 MW
	2	Coal	153	Summer Capacity = 145 MW
	3	Coal	155	Summer Capacity = 145 MW
	4	Coal	155	Summer Capacity = 145 MW
Pt. Tupper	2	Coal	150	Summer Capacity = 148 MW
Trenton	5	Coal	150	Summer Capacity = 135 MW
	6	Coal	157	Summer Capacity = 155 MW
Pt. Aconi	1	Coal	168	
Burnside	1	Lt Oil	33	Proposed converion to Natural Gas in 2006 for all units,
	2	Lt Oil	33	while retaining Lt. Oil capability on Units 1 and 3.
	3	Lt Oil	33	Summer Capacity = 25 MW for all units
	4	Lt Oil	33	
Victoria Junction	1	Lt. Oil	33	Summer Capacity = 25 MW
	2	Lt. Oil	33	Summer Capacity = 25 MW
Tusket	1	Lt. Oil	24	Summer Capacity = 21 MW
Wreck Cove	1	Hydro	115	
	2	Hydro	115	
Annapolis		Hydro	4	
Avon		Hydro	7	
Black River		Hydro	22	
Nictuax		Hydro	7	
Lequille		Hydro	11	
Paradise		Hydro	5	
Mersey		Hydro	42	
Sissiboo		Hydro	24	
Bear River		Hydro	13	
Tusket		Hydro	2	
Roseway		Hydro	2	
St. Margrets		Hydro	11	
Sheet Harbour		Hydro	11	
Dickie Brook		Hydro	4	
Fall River		Hydro	1	
IPP	All	NUG	25	
TOTAL CAPACITY			**2311**	Total Capacity as of January 2005

Table A – 2 Maritimes Area Resources (cont'd)

MECL Resources				
Plant	**Unit**	**Type**	**Capacity MW**	**Notes**
Charlottetown	6	Oil	5	
	7	Oil	7	
	8	Oil	10	
	9	Oil	19	
	10	Oil	19	
Borden	1	Diesel	15	
	2	Diesel	25	
Summerside Diesel		Diesel	10	Owned by the city of Summerside
TOTAL CAPACITY			**110**	Total Capacity as of January 2005

Note: MECL Resources include a 20 MW ownership in the Dalhousie Plant and a 30 MW participation in Point Lepreau. These units are NBSO units and are shown in the NBSO resources.

Table A – 2 Maritimes Area Resources (cont'd)

NMISA Resources				
Plant	**Unit**	**Type**	**Capacity MW**	**Notes**
Tinker		Hydro Diesel	35 1	
Caribou		Diesel Hydro	7 1	
Wheelabrator Sherman		Wood	19	Planned retirement in December 2006
Boralex – Ashland (FF)		Wood	30	
Boralex – Ashland (AEI)		Wood	37	In-service January 2005
Squa Pan		Hydro	1	
Flo's Inn		Diesel	4	
Loring		Diesel	6	
TOTAL CAPACITY			141	Total Capacity as of January 2005

Table A - 3

Summary of Changes in Capacity

Year	January Capacity MW	December Capacity MW	Capacity Change MW	Explanation
2005	6664	6688	+24	Charlottetown Diesel (+49), Wheelabrator retired (-19) Point Lepreau derated (-6)
2006	6688	6734	+46	Tuft's Cove 6 (+52), Point Lepreau derated (-6)
2007	6734	6725	-9	Point Lepreau derated (-9)
2008	6725	6147	-578	Point Lepreau Refurbishment begins April 2008 (-578)
2009	6147	6782	+635	Point Lepreau Refurbishment ends October 2009 (+635)

2.2 Unit Unavailability Factors

2.2.1 Types of Unavailability Factors Represented

The types of unavailability factors represented in this reliability assessment are forced outages and planned outages. Forced outages include unplanned maintenance outages, deferrable forced outages, starting failure outages and unit deration adjustments. All except planned outages are included in the Forced Outage Rates (FORs) presented in Table A-4. Planned outages are scheduled manually for the reliability program based upon projected maintenance schedules.

2.2.2 Source of Unavailability Factors

Forced Outage Rates for existing units are based on actual outage data as well as on data of similar sized units as compiled by the Canadian Electricity Association (CEA).

FORs for new units are based upon the utilities' experience with similar units in conjunction with averages compiled by the Canadian Electricity Association (CEA).

2.2.3 Maturity Considerations

Immature FORs were not used in this evaluation.

2.2.4 Tabulation of Typical Unavailability Factors

The ranges of typical FORs used in the assessment are tabulated in Table A-4. These values are consistent with those used in the business plans of the Maritimes Area utilities and reflect the results of maintenance and operational strategies.

Table A - 4

Maritimes Area Typical Forced Outage Rates

Unit Type	Forced Outage Rate %
Hydro	1 - 8
Nuclear	5
Coal	2 - 8
Oil	5 - 10
Natural Gas (Combined Cycle)	3 - 10
Oil / Gas	2 - 10
Orimulsion® / Oil	8
Other	3 - 5

2.3 Purchase and Sale Representation

Purchases and sales are represented as an adjustment to the capacity or load as appropriate.

2.4 Retirements

Retirements were considered by removing the units from the model at their retirement date.

3.0 Representation of Interconnected Systems

Interconnections were not explicitly modeled. The approach used in this evaluation was to determine the level of interconnection assistance required in order for the Maritimes Area to meet the NPCC criterion.

4.0 Modeling of Limited Energy Sources

Under normal operating conditions, the hydro system is operated considerably below its DMNC rating due to economics. However, if required to maintain customer load, it would be operating at full capacity by utilizing the headponds and other existing storage reservoirs. This is one of the options documented in the Emergency Operating Procedures (Section 2.2). Therefore, in the evaluation, hydro units are considered available for all hours during which the unit is not on forced outage or maintenance.

5.0 Modeling of Demand Side Management

The expected monthly demand and energy reduction due to Demand Side Management programs for each utility is included in their respective forecasts and in the combined Maritimes Area forecast in Table A-1.

6.0 Modeling of Non-Utility Generation

NBSO and NS Power each aggregate small non-utility generating capacity into a single unit with operating characteristics and FORs equivalent to other Maritimes Area units of similar size. These are tabulated in Table A-2 and are identified by type NUG. The Bayside 6 unit is modeled separately because its size is comparable to the larger units on the system.

7.0 Other Assumptions

Internal transmission limitations were not modeled. The results of isolated pool modeling for the NPCC Summer 2004 Multi-Area Probabilistic Reliability Assessment have shown that the ability of the Maritimes Area to meet the NPCC resource adequacy criterion is not affected by any internal transmission limitations.

The study assumed that there would be no unit slippages or unit deratings due to environmental constraints.

APPENDIX B

DESCRIPTION OF RELIABILITY PROGRAM

DESCRIPTION OF RELIABILITY PROGRAM

The program used for this assessment, LOLP, was originally developed at NB Power in 1984 in order to complete the Triennial Review of Resource Adequacy. Since that time the program has been improved, and its capabilities expanded, with the most recent modifications being completed in May 2001.

The program is a single area program that performs the classical LOLP analysis based upon the weekday peak hour load, as well as an LOLH and EENS analysis which is based upon all of the hourly loads. The results of the program have been benchmarked against the results of the IEEE reliability test system, as well as against the results of the PICES program used by NS Power for the 1991 Triennial Review. The program was further benchmarked by evaluating its results against those documented in the 1992 CIGRE Task Force 38-03-10 report “Composite Power System Reliability Analysis Application to the New Brunswick Power Corporation System"” In all cases, excellent agreement of results was observed.

The base load shape for the program is input in the form of EEI format system hourly net loads for each utility (maximum of 5) comprising the Area. Monthly load shapes for the individual utilities are created by scaling the hourly loads to match the load forecast values of both demand and energy. A monthly load shape for the Area is then obtained by combining the monthly load shapes of the individual utilities. This method preserves the effects of load chronology as well as load coincidence between the utilities. A separate monthly load shape comprising only the peak load of each weekday is created for the classical LOLP analysis.

The program utilizes a two state capacity model from which it constructs a table of the cumulative probability of all of the capacity outage states having a probability greater than a user set threshold (1.0E-08 for this analysis). The table is modified, if necessary, on a monthly basis to account for capacity additions, unit retirements, or units going on, or coming off, maintenance. Note that the maintenance schedule is input by the user.