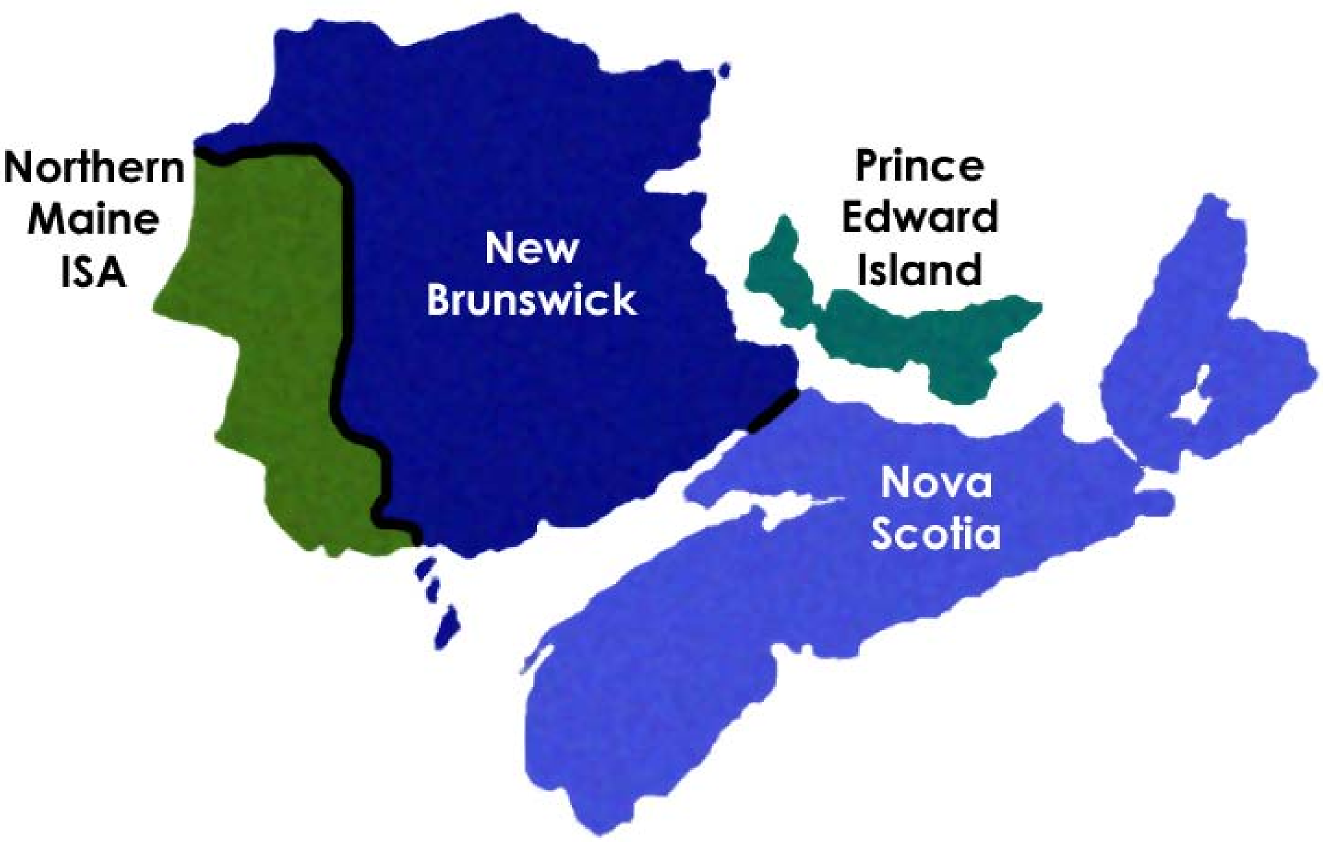
Approved by the RCC
September 9, 2010

NPCC
2010 MARITIMES AREA
COMPREHENSIVE REVIEW OF RESOURCE ADEQUACY



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

August 2010

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EXECUTIVE SUMMARY

The 2010 Maritimes Area Comprehensive Review of Resource Adequacy, covering the period of January 2011 through December 2015, has been prepared to satisfy the compliance requirements as established by the Northeast Power Coordinating Council (NPCC). The guidelines for this review are specified in the *NPCC Regional Reliability Directory #1 Appendix D (Adopted: December 1, 2009).* This review supplants the previous Comprehensive Review that was performed in 2007 and approved by the RCC on March 5, 2008.

Table 1 provides a summary of the Major Assumptions and Results of this review.

Table 1: Summary of Major Assumptions and Results

MAJOR ASSUMPTIONS	
Load Forecast	2010 All Jurisdictions
Load Shape (all years)	2006/07
Resource Adequacy Criterion	Loss of Load Expectation less than or equal to 0.1 days/year
Maritimes Required Reserve	20% of peak firm load
Interconnection Benefits	None assumed for this analysis

RESULTS

Year	**Expected Number of Firm Load Disconnections Days/year**	**Interconnection Support to meet Criterion (0.1 Days/year) MW**
2011	0.037	0
2012	0.002	0
2013	0.002	0
2014	0.003	0
2015	0.004	0

The 2011 coincident peak forecast for the Maritimes Area is 5,445 MW, which is 264 MW below the 5,709 MW forecast in the 2007 review. This reduced load forecast reflects significant load decreases in mining, forestry and pulp and paper industries, slower customer load growth in reaction to higher charges for electricity, and government sponsored as well as rate payer and participant funded energy efficiency programs. The average annual demand growth over the 2011-15 study period of this review is -0.01%, which is lower than the 0.88% annual demand growth forecast in the 2007 review.

The reserve criterion for the Maritimes Area is 20%, and adherence to this criterion is demonstrated to comply with the NPCC reliability criterion.

The NPCC reliability criterion of less than or equal to 0.1 days of firm load disconnections per year is not exceeded by the Maritimes Area for all years covered by this review, and varies between 0.002 to 0.037 days/yr for the base load forecast with load forecast uncertainty. The Maritimes Area is also shown to adhere to its own 20% reserve planning criterion in all years for the base load forecast, with reserve levels varying between 24% and 36%. For the high load forecast sensitivity, the Maritimes Area also adheres to its 20% reserve criterion for all years, varying between 24% and 34%.

The 2007 NPCC report *Review of Interconnection Assistance Reliability Benefits* confirmed that the Maritimes Area has a Maximum Tie Benefit Potential equal to its import capability. However, the Area does not require interconnection assistance to meet its 20% reserve criterion for all years of this study.

The projected return to service of the refurbished 660 MW Point Lepreau generating station in New Brunswick is March 31, 2011. A sensitivity analysis was performed to determine the impact of a one year delay of the return of the Point Lepreau generator. The 2012 reserve margin for the extended outage period drops from 36% to 23% but still meets the Area's 20% reserve capacity criterion.

An additional sensitivity was performed in which the credit for wind project capacity in the Maritimes Area was set to zero. The Maritimes Area exceeds its 20% reserve criterion in all years except 2011 (when the Point Lepreau generator is out of service) where its reserve margin is 19%, falling 73 MW short of the 20% criterion. This shortfall represents less than 5% of the import capability to the Area and demonstrates that the Maritimes Area is not overly reliant on wind capacity to meet its 20% reserve planning criterion.

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1.0 INTRODUCTION

The 2010 Maritimes Area Comprehensive Review of Resource Adequacy, covering the period of January 2011 through December 2015, has been prepared to satisfy the compliance requirements as established by the Northeast Power Coordinating Council (NPCC). The guidelines for this review are specified in *NPCC Directory #1 Appendix D, Guidelines for Area Review of Resource Adequacy (Adopted: December 1, 2009*). This review supplants the previous Comprehensive Review that was performed in 2007 and approved by the RCC on March 5, 2008.

The Maritimes Area is a winter peaking area with separate markets and regulators in New Brunswick, Nova Scotia, Prince Edward Island (PEI), and Northern Maine. The New Brunswick System Operator (NBSO) is the Reliability Coordinator for the Maritimes Area.

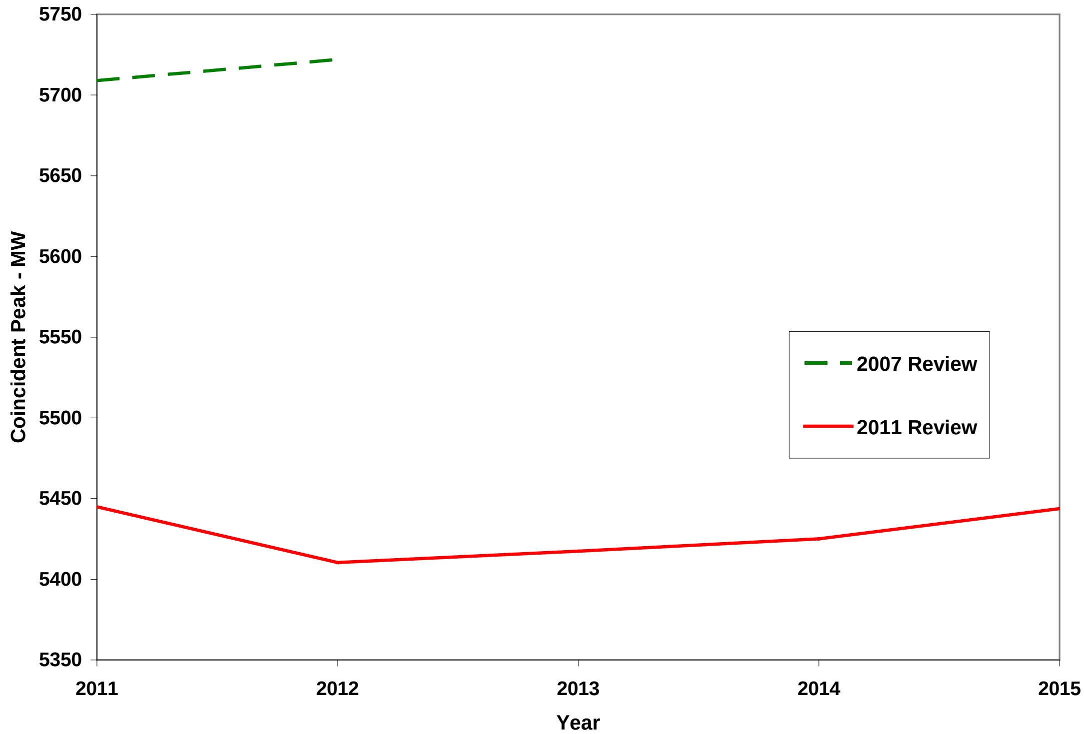
Table 2 and Figure 1 provide a comparison of the load forecasts in the 2010 and 2007 reviews. The coincident peak forecast for 2011 is 5,445 MW, which is 264 MW below the 5,709 MW forecast in the 2007 Comprehensive Review. This reduced load forecast reflects significant load decreases in mining, forestry and pulp and paper industries, slower customer load growth in reaction to higher charges for electricity, and government sponsored as well as rate payer and participant funded energy efficiency programs. The average annual growth in demand over the study period of this review is -0.01%, which is lower than the 0.88% annual demand growth forecast in the 2007 review.

A capacity reserve criterion for the Maritimes Area is described in 2.3 and adherence to this criterion is demonstrated in 3.1 for both base case and high load forecasts. Further, this reserve capacity criterion is shown to comply with the NPCC reliability criterion in 2.4.

Table 2: Comparison of Load Forecasts

Winter Peak (Month of January)	**2010 Review MW**	**2007 Review MW**
2011	5,445	5,709
2012	5,410	5,722
2013	5,417	N/A
2014	5,425	N/A
2015	5,444	N/A
Five Year Period	**2011 - 2015**	**2008 - 2012**
Annual Average Growth Rate	-0.01%	0.88%

Figure 1: Comparison of Load Forecasts



2.0 RESOURCE ADEQUACY CRITERION

2.1 Statement of Resource Adequacy Criterion

For planning purposes, New Brunswick, Nova Scotia, and PEI individually apply a capacity based criterion in determining their required reserves. Northern Maine does not apply a capacity based criterion beyond the NPCC reliability criterion.

New Brunswick and Nova Scotia each plans for a reserve equal to the largest generator or 20% of the firm load. PEI plans for a reserve equal to 15% of its firm load. As a simplification, this review applies the 20% reserve criterion to the Maritimes Area as a whole because of the relatively small sizes of PEI and Northern Maine to the combined jurisdictions of New Brunswick and Nova Scotia. 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 (from *NPCC Directory #1 Appendix D, Guidelines for Area Review of Resource Adequacy (Adopted: December 1, 2009*) states:

> The probability (or risk) of disconnecting **firm load** due to resource deficiencies shall be, on average, not more than one day in ten years as determined by studies conducted for each Resource Planning and Planning Coordinator Area. Compliance with this criterion 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 Planning Coordinator Areas, transmission transfer capabilities, and capacity and/or **load** relief from available operating procedures.

2.2 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 System Operator 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 generators.

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

3. Cancel economy and other external interruptible sales.

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

5. Synchronize and load combustion turbines.

6. Purchase capacity from Hydro-Québec.

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 (1-5 MW)

11. Load up thermal generators 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.

2.3 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 3.1.

2.4 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 2.1, it is necessary to evaluate the system LOLE with the area's firm load scaled so that the reserve is equal to 20%. 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 0.147 days/year. The NPCC criterion of 0.1 days/year expected number of customer disconnections as stated in Section 2.1 allows for the inclusion of the effects of interconnections.

When the Maritimes Area has a reserve of 20% with the interruptible load removed, approximately 70 MW of interconnection assistance is required to meet the NPCC criterion. This represents less than 5% of the normal import capabilities with Quebec (1000 MW) and New England (550 MW)[*]. The 2007 NPCC report *Review of Interconnection Assistance Reliability Benefits* confirmed that the Maritimes Area has a Maximum Tie Benefit Potential equal to its import capability.

The preceding leads to the conclusion that the reserve criterion of the Maritimes Area meets the NPCC Resource Adequacy Criterion with minimal interconnection assistance.

2.5 Recent Reliability Studies

System Operators in New Brunswick, Nova Scotia, PEI, and Northern Maine individually conduct internal reviews of their capacity requirements by comparison of generation sources with forecast loads according to the reserve criterion described previously.

[*] The 550 MW import capability from New England into New Brunswick is conditionally firm depending on the status of generators in Maine. The unconditional firm import capability from New England to New Brunswick is 300 MW.

The results presented in this review are based upon an evaluation conducted during the third quarter of 2010 for the period 2011 through 2015.

To determine load forecast uncertainty (LFU) 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.

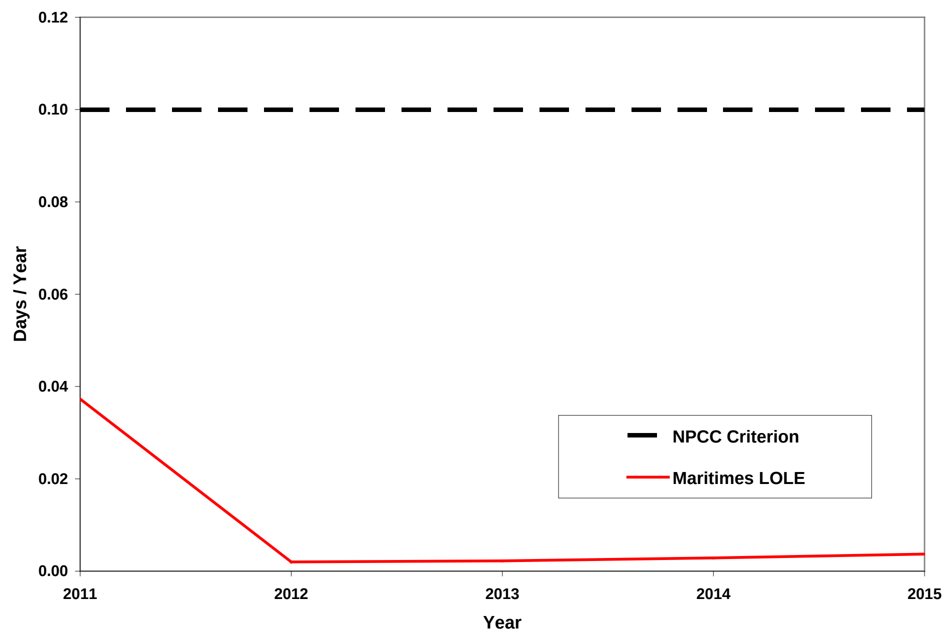
It is assumed that the forecast error is approximately normally distributed around the forecast value, and that the contribution to system LOLE is negligible when loads are less than the forecast value by more than ½ standard deviation. This results in weighting factors of 0.383, 0.242, and 0.067 for 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 3 and Figure 2 demonstrate that the Maritimes Area system meets the NPCC criterion of 0.1 days/year without interconnection assistance for all years of the 2011-15 study period.

Table 3: Expected Number of Firm Load Disconnections – Base Case with Load Forecast Uncertainty

Calendar Year	Expected Number Of Firm Load Disconnections days/year	Interconnection Support to meet Criterion (0.1 days/year) MW
2011	0.037	0
2012	0.002	0
2013	0.002	0
2014	0.003	0
2015	0.004	0

Figure 2: Expected Number of Firm Load Disconnections

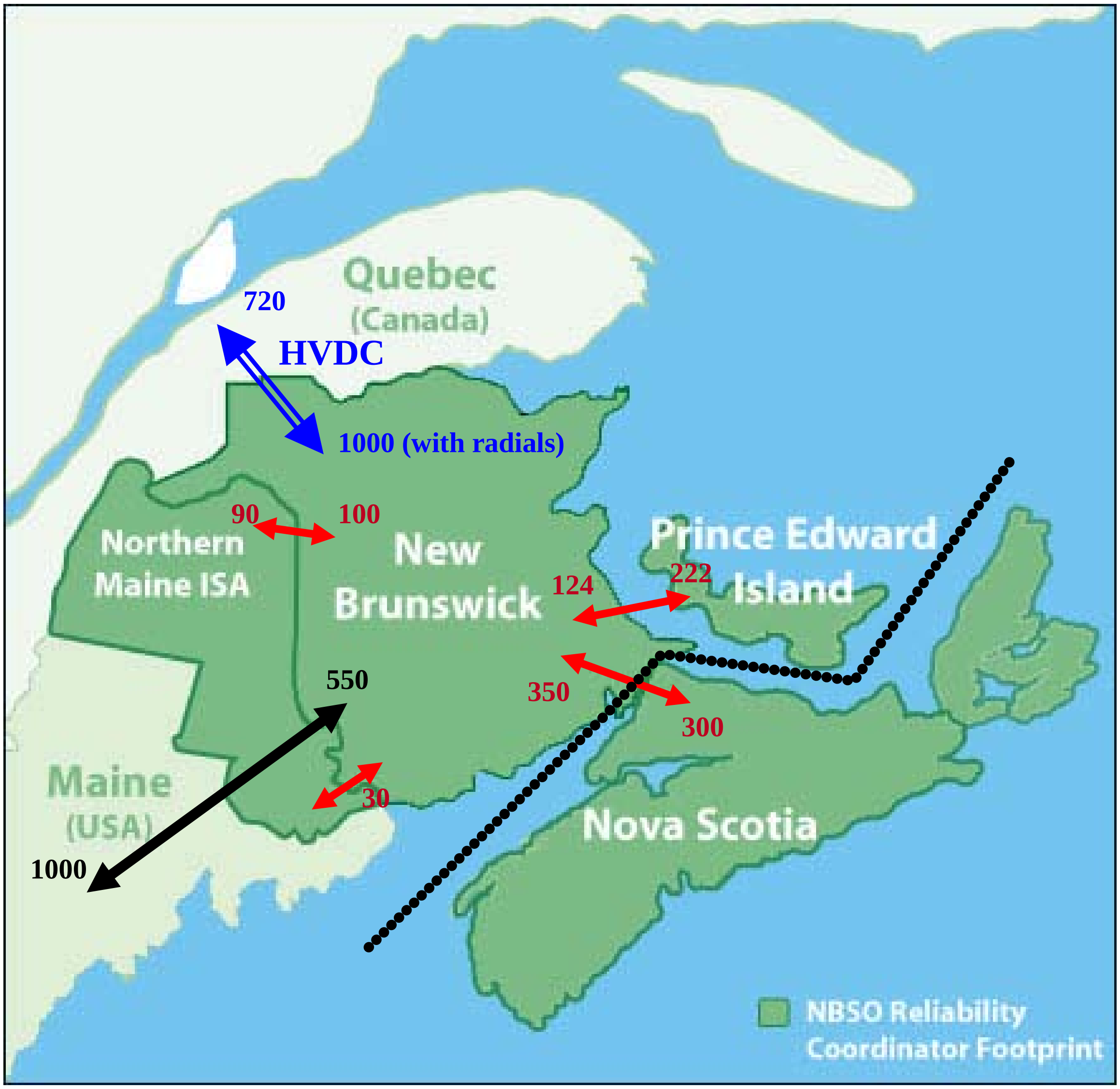


2.6 Intra-Area Transmission Capacity Limits

Within the Maritimes Area, the areas of Nova Scotia, PEI, and Northern Maine are each connected only to New Brunswick as per Figure 3. A transmission congestion issue of consequence to the LOLE results occurs for only one of these three interconnections, the tie between New Brunswick and Nova Scotia.

Transmission capacity limits between Northern Maine and New Brunswick were not modeled for this analysis. These normal limits are a result of parallel operation of four lines (2 - 138 kV, 2 - 69 kV) that Northern Maine keeps below thermal ratings to ensure that the trip of one of these lines doesn't overload the others. Should one or more contingencies occur in Northern Maine, the lines can be switched from parallel to radial mode. This effectively allows for a high enough transfer limit from New Brunswick to meet the peak load in Northern Maine.

Figure 3: Intra-Area Transmission Capacity Limits



** The 550 MW import capability from New England into New Brunswick is conditionally firm depending on the status of generators in Maine. The unconditional firm import capability from New England to New Brunswick is 300 MW.

3.0 RESOURCE ADEQUACY ASSESSMENT

3.1 Comparison of Planned and Required Reserve – Base Case

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 4 and Figure 4 represent the results of the reserve comparison for the base load forecast. In each year of the analysis, the planned reserve is greater than the required reserve.

Table 4: Comparison of Planned and Required Reserve - Base Load Forecast

Month Of January	Installed Capacity MW	Forecast Coincident Peak MW	Interruptible Load MW	Planned Reserve		Required Reserve	
				MW	%	MW	%
2011	6,289	5,445	378	1,222	24%	1,013	20%
2012	6,861	5,410	377	1,828	36%	1,007	20%
2013	6,861	5,417	370	1,814	36%	1,009	20%
2014	6,861	5,425	362	1,798	36%	1,013	20%
2015	6,901	5,444	354	1,811	36%	1,018	20%

3.2 Comparison of Planned and Required Reserve – High Load Growth

Table 5 and Figure 4 illustrate the changes in planned and required reserve if the annual growth rate is 1% higher than forecast (i.e. 0.99% per year versus -0.01% per year). The results show that the resource plan of the Maritimes Area is sufficient to maintain a reserve of 20% or greater for all years of the study period.

Table 5: Comparison of Planned and Required Reserve - High Load Growth

Month Of January	Installed Capacity MW	Forecast Coincident Peak MW	Interruptible Load MW	Planned Reserve		Required Reserve	
				MW	%	MW	%
2011	6,289	5,445	378	1,222	24%	1,013	20%
2012	6,861	5,499	377	1,739	34%	1,024	20%
2013	6,861	5,554	370	1,677	32%	1,036	20%
2014	6,861	5,609	362	1,614	31%	1,049	20%
2015	6,901	5,665	357	1,590	30%	1,061	20%

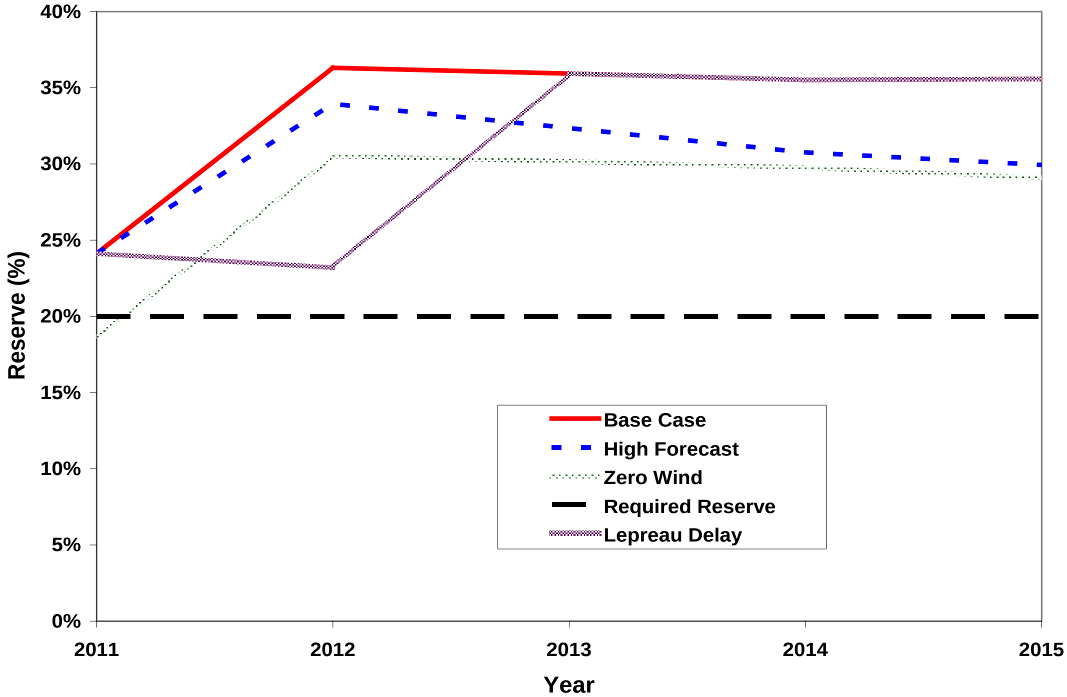
3.3 Comparison of Planned and Required Reserve – Zero Wind

To determine the impact of wind capacity in allowing the Maritimes Area to achieve its required reserve, a sensitivity analysis was performed with the wind capacity on the system given a zero capacity credit. Table 6 and Figure 4 illustrate the planned and required reserve for the zero wind capacity credit scenario. The results show that Maritimes Area exceeds its 20% reserve criterion in all years except 2011 where its reserve margin is 19%, 73 MW short of the 20% criterion. This shortfall represents less than 5% of the Maritimes Area total tie benefits capability. The conclusion from this sensitivity is that the Maritimes Area is not overly reliant on wind capacity to achieve its 20% reserve criterion.

Table 6: Comparison of Planned and Required Reserve - Zero Wind

Month Of January	Installed Capacity MW	Forecast Coincident Peak MW	Interruptible Load MW	Planned Reserve		Required Reserve	
				MW	%	MW	%
2011	6,007	5,445	378	940	19%	1,013	20%
2012	6,570	5,410	377	1,537	31%	1,007	20%
2013	6,570	5,417	370	1,523	30%	1,009	20%
2014	6,570	5,425	362	1,507	30%	1,013	20%
2015	6,570	5,444	354	1,480	29%	1,018	20%

Figure 4: Planned Versus Required Reserve



3.4 Comparison of Planned and Required Reserve - Point Lepreau Delay

The estimated time for the return to service of the refurbished Point Lepreau generating station in New Brunswick is March 31, 2011. Cases were run to determine the impact of a one year delay of the return of the Point Lepreau generator. The results are shown in Table 7. The 2012 reserve margin drops from 36% to 23% yet still meets the Area's 20% reserve capacity criterion.

Table 7: Comparison of Planned and Required Reserve – Point Lepreau Delay

Month Of January	Installed Capacity MW	Forecast Coincident Peak MW	Interruptible Load MW	Planned Reserve		Required Reserve	
				MW	%	MW	%
2011	6,289	5,445	378	1,222	24%	1,013	20%
2012	6,201	5,410	377	1,168	23%	1,007	20%
2013	6,861	5,417	370	1,814	36%	1,009	20%
2014	6,861	5,425	362	1,798	36%	1,013	20%
2015	6,901	5,444	354	1,811	36%	1,018	20%

3.5 Contingency Plans

The Maritimes Area utilities' forecast high and low load growth scenarios, and their impact on the generation dispatch is continually being evaluated 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.

4.0 PLANNED RESOURCE CAPACITY MIX

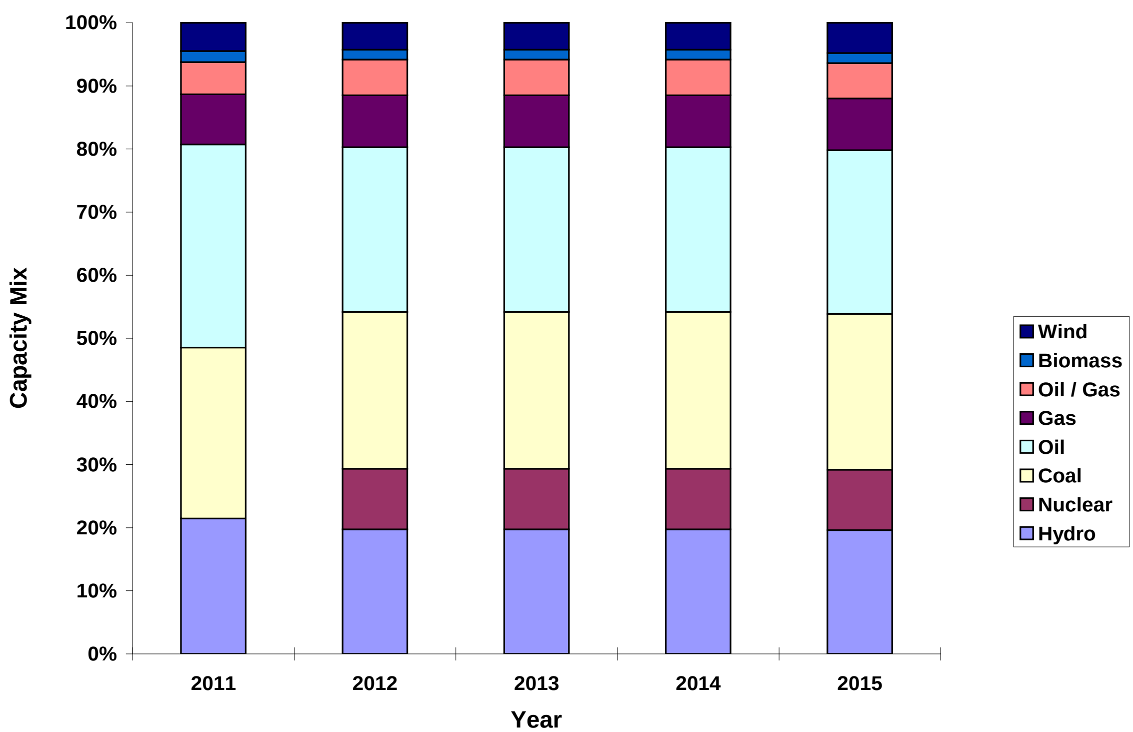
4.1 Planned Resource Capacity Mix

Table 8 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 8: Planned Resource Capacity Mix

Month Of January	Hydro %	Nuclear %	Coal %	Oil %	Gas %	Oil /Gas %	Biomass %	Wind %
2011	21	0	27	32	8	5	2	4
2012	20	10	25	26	8	6	2	4
2013	20	10	25	26	8	6	2	4
2014	20	10	25	26	8	6	2	4
2015	20	10	25	26	8	6	2	5

Figure 5: Planned Resource Capacity Mix



4.2 Reliability Impact of Resource Diversification Strategy

As can be seen from Table 8 and the associated Figure 6, 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.

The Maritimes Area continues to see an increase in wind energy projects. PEI currently has 164 MW of wind capacity with an outstanding request for proposals for up to 130 MW of additional capacity. Northern Maine has 42 MW of existing wind capacity while Nova Scotia has 116 MW of installed wind capacity, with an additional 187 MW expected in 2011. New Brunswick has 195 MW of installed wind capacity with 54 MW more by December 2010 and about 40 MW more by the end of 2011.

Late in 2007, a second 345 kV interconnection between New Brunswick and New England was commissioned, increasing the Maritimes Area’s import capability by 550 MW and its export capability by 300 MW. The new tie benefits both areas because the peak loads of the two systems occur at different times of the year (the Maritimes during winter and New England during summer).

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 2006/2007 system load data provided a typical Maritimes Area load shape. Demand and energy forecasts for 2011 to 2015 inclusive were prepared by each system operator. 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**
2011	5445	5366	4910	4268	3686	3439	3480	3421	3392	3893	4452	5189	5445
2012	5410	5303	4865	4341	3713	3455	3518	3449	3439	3951	4501	5248	5410
2013	5417	5322	4915	4352	3734	3477	3530	3460	3463	3963	4527	5267	5417
2014	5425	5334	4909	4375	3742	3486	3538	3466	3461	3969	4526	5269	5425
2015	5444	5349	4923	4381	3760	3493	3545	3473	3471	3979	4535	5283	5444
ENERGY GWh													
Year	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**	**Total**
2011	3049	2765	2761	2327	2141	1973	1994	2005	1965	2193	2414	2827	28414
2012	3028	2733	2727	2353	2158	1988	2015	2025	1995	2227	2446	2863	28558
2013	3037	2745	2745	2360	2164	1994	2021	2031	2003	2235	2455	2871	28661
2014	3045	2749	2746	2366	2172	1998	2019	2030	2001	2234	2455	2871	28686
2015	3052	2758	2758	2373	2178	2003	2023	2034	2007	2239	2463	2882	28770
INTERRUPTIBLE DEMAND MW													
Year	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**	**On Peak**
2011	378	380	362	368	386	385	385	379	387	381	388	378	378
2012	377	381	362	369	386	386	386	380	388	382	389	379	377
2013	370	378	360	366	384	383	383	378	386	379	386	376	370
2014	362	375	357	363	381	380	380	374	382	376	383	373	362
2015	354	372	354	360	377	377	377	371	379	373	380	370	354

Note: The forecast coincident demand occurs in January.

1.2 Load forecast uncertainty (LFU) was considered in the analysis as described in Section 2.5.

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 Generator Resource Representation

Generator 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 2011 - 2015 inclusive. The following sections document the tabulated data.

2.1 Generator Ratings

2.1.1 Definition

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

2.1.2 Procedure for Verifying Ratings

Ratings of NB Power generators 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 generator testing and from the generation reliability system is used in conducting these reviews. The Generation Services Department at Nova Scotia Power, Inc. (NSPI) reviews generator capability ratings on an annual basis. The past year's operating data is examined and the rating is based on the average of the top 1 percent of 2-hour generator outputs.

Table A - 2: Maritimes Area Resources

New Brunswick Resources				
Plant	**Unit**	**Type**	**Capacity MW**	**Notes**
Point Lepreau	1	Nuclear	660	Return to service March,31, 2011
		Diesel	5	
Belledune	2	Coal	457	
Coleson Cove	1	Oil	324	
	2	Oil	324	
	3	Oil	324	
Dalhousie	1	Oil	96	Retiring April 1, 2011
	2	Oil	203	Retiring April 1, 2011
Bayside	6	Natural Gas	263	Capacity includes Combined Cycle Operation
Grandview	1	Natural Gas	45	
	2	Natural Gas	45	
Grand Manan	3	Diesel	29	
Millbank	1	Diesel	99	Summer Capacity = 90 MW
	2	Diesel	99	Summer Capacity = 90 MW
	3	Diesel	99	Summer Capacity = 90 MW
	4	Diesel	99	Summer Capacity = 90 MW
Ste Rose	1	Diesel	99	Summer Capacity = 90 MW
NB Wind	All	Wind	100	250 nominal: 100 winter, 50 summer
NUG Purchases		Biomass/Hydro	54	
Mactaquac	1	Hydro	109	
	2	Hydro	109	
	3	Hydro	109	
	4	Hydro	115	
	5	Hydro	112	
	6	Hydro	112	
Beechwood	1	Hydro	36	
	2	Hydro	36	
	3	Hydro	40	
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	
Nepisiguit Falls	1	Hydro	11	
TOTAL CAPACITY			**3650**	Total Capacity January 2011excl. Point Lepreau

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

Nova Scotia Resources				
Plant	**Unit**	**Type**	**Capacity (MW)**	**Notes**
Tufts Cove	1	Gas/Oil	81	
	2	Gas/Oil	93	
	3	Gas/Oil	147	
	4	Natural Gas	49	Summer Capacity = 46 MW
	5	Natural Gas	49	Summer capacity = 46 MW
	6	Natural Gas	49	Summer capacity = 46 MW
Lingan	1	Coal	153	
	2	Coal	153	
	3	Coal	158	
	4	Coal	153	
Pt. Tupper	2	Coal	152	
Trenton	5	Coal	150	Summer Capacity = 135 MW
	6	Coal	157	
Pt. Aconi	1	Coal	171	
Burnside	1	Lt Oil	33	Summer Capacity = 25 MW
	2	Lt Oil	33	Summer Capacity = 25 MW
	3	Lt Oil	33	Summer Capacity = 25 MW
	4	Lt Oil	33	Summer Capacity = 25 MW
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	106	
	2	Hydro	106	
Annapolis		Hydro	4	
Avon		Hydro	8	
Black River		Hydro	23	
Nictuax		Hydro	8	
Lequille		Hydro	13	
Paradise		Hydro	5	
Mersey		Hydro	42	
Sissiboo		Hydro	28	
Bear River		Hydro	12	
Tusket		Hydro	3	
Roseway		Hydro	2	
St. Margrets		Hydro	10	
Sheet Harbour		Hydro	10	
Dickie Brook		Hydro	3	
Fall River		Hydro	1	
NUG Purchases	All	Biomass/Hydro	28	
NS Wind Projects	All	Wind	99	303 MW Nominal Rating, Winter Firm Capacity = 99 MW, Summer Firm Capacity = 60 MW
TOTAL CAPACITY			**2448**	Total Capacity as of January 2011

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

Prince Edward Island Resources				
Plant	**Unit**	**Type**	**Capacity MW**	**Notes**
Charlottetown	6	Oil	5	
	7	Oil	7	
	8	Oil	10	
	9	Oil	19	
	10	Oil	19	
	11	Diesel	49	
Borden	1	Diesel	15	Summer Capacity = 12 MW
	2	Diesel	25	Summer Capacity = 20 MW
Summerside Diesel		Diesel	10	Owned by the City of Summerside
PEI Wind	All	Wind	66	164 MW Nominal Rating, Winter Firm Capacity = 66 MW, Summer Firm Capacity = 33 MW
TOTAL CAPACITY			**225**	Total Capacity as of January 2011

Note: MECL Resources include a 20 MW ownership in the Dalhousie Plant and a 30 MW participation in Point Lepreau. These are NB Power generators and are shown in the New Brunswick generation resources.

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

Northern Maine Resources				
Plant	**Unit**	**Type**	**Capacity MW**	**Notes**
Tinker		Hydro Diesel	35 1	
Caribou Oil		Oil	22	
Caribou		Diesel Hydro	7 1	
Boralex – Ashland (FF)		Wood	33	
Boralex – Ashland (AEI)		Wood	37	
Squa Pan		Hydro	1	
Flo's Inn		Diesel	4	
Loring		Diesel	6	
NMISA Wind	All	Wind	17	42 MW Nominal Rating, Winter Firm Capacity = 17 MW, Summer Firm Capacity = 8 MW
TOTAL CAPACITY			164	Total Capacity as of January 2011

Table A - 3: Summary of Changes in Capacity

Year	January Capacity MW	December Capacity MW	Year over Year Capacity Change MW	Explanation
2011	6289	6742	+453	Point Lepreau returns (+660), Dalhousie retires (-299), Millbank contract expires (+198) NS Hydro maintenance (-106)
2012	6742	6861	+119	NS Hydro returns (+106) ,NS Wind (+9 firm), NS Hydro upgrade (+4)
2013	6861	6861	+0	
2014	6861	6861	+0	
2015	6861	6901	+40	NS Wind (+40)

2.2 Generator 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 generator derating 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.

New Brunswick forced outage rates are calculated as per MP-12-A – Criteria and Considerations in the Determination and Certification of Eligible Installed Capacity and Eligible Unforced Capacity (http://www.nbso.ca/Public/_private/MP-12-A.pdf). The calculation in this Market Procedure is consistent with the DAFOR (derating adjusted forced outage rate) calculation in IEEE Standard 762-2006, Section 8.17.4.

NSPI uses the DAFOR (derating adjusted forced outage rate) calculation for forced outage rates in IEEE Standard 762-2006, Section 8.17.4. NSPI maintains a database of combustion turbine and fossil generator reliability and performance data and is a contributing utility to the Canadian Electricity Association Equipment Reliability Information System (CEA-ERIS). The CEA-ERIS also calculates DAFOR using the industry standard definition as per IEEE 762-2006.

The forced outage rates for the smaller PEI and Northern Maine systems are modeled using forced outage rates for generators of similar size and fuel type in New Brunswick and Nova Scotia. Most of the small diesel and oil fuelled generators in these systems operate less than 100 hours per year, and statistics necessary for calculating their DAFOR values are not available. The modeled FOR values for generators in these systems are between 5 – 10 %.

2.2.2 Source of Unavailability Factors

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

FORs for new generators are based upon the utilities' experience with similar generators 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 Forced Outage Rates

The ranges of 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 Forced Outage Rates

Unit Type	Forced Outage Rate %	
	2010 Review	2007 Review
Hydro	1 - 8	1 - 5
Nuclear	4	4
Coal	2 -4	2 – 28*
Oil**	1 – 10	4 - 10
Natural Gas	2 - 4	3 - 4
Oil / Gas	2	2
Biomass	3	3
Wind (after derating)	0	1

* Only one coal generator had a forced outage rate as high as 28%. All other coal generators had forced outage rates at 4% or less.

** Most Light Oil fuelled generators are in the range of 1-5%. Two smaller Combustion turbines and some of the heavy oil fuelled generators are in the order of 8-10%.

2.3 Purchase and Sale Representation

Purchases and sales are represented as an adjustment to the capacity or load as appropriate. In the past study, Millbank generators 3 and 4 were included as Hydro-Québec capacity. These generators will return to the New Brunswick resources as of November 2011.

2.4 Retirements

Retirements were considered by removing the generators from the model at their retirement date. The Grand Lake generator, included in the 2007 review as a New Brunswick resource, has been retired. The New

Brunswick generation resources at Dalhousie are expected to be retired as of April 1, 2011.

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 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 generators are considered available for all hours during which the generator is not on forced outage or maintenance. There are no seasonal adjustments to the DMNC ratings of the hydro generators.

5.0 Modeling of Demand Side Management

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

6.0 Modeling of Non-Utility Generation

Small non-utility generators are aggregated into single units with operating characteristics and FORs equivalent to other Maritimes Area generators of similar size. These are tabulated in Table A-2 and are identified by type NUG. Larger non-utility generators, such as Bayside 6, are shown separately because their size is comparable to the larger utility generators on the system.

7.0 Other Assumptions

The study assumed that there would be no generator slippages or deratings due to environmental constraints within the five-year timeframe of this review. Current emission limits are specified as annual system volumes rather than generator specific volumes, providing flexibility in the operation of the fleet.

Future regulations limiting greenhouse gas emissions are expected and could pose a risk for the future utilization of fossil fuelled generation. System Operators in the Maritimes Area will be tracking such standards as they are implemented and may conduct analyses in the future regarding their impact on resource adequacy.

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 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 Fall 2007.

The original program was a single area program that performed 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 were benchmarked against the results of the IEEE reliability test system, as well as against the results of the PICES program used by NSPI 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.

In the Fall of 2007, modifications to the original program allowed it to perform a Monte Carlo analysis of a multi-area system with intra-area tie limits. This Monte Carlo simulation was written using MATLAB® software for programming and random number generation, and it performs as follows:

- For each daily coincident peak load, generation is simulated in each jurisdiction of the Maritimes. This simulation uses random numbers against a generator’s Forced Outage Rate to determine the status of each generator. Planned generator maintenance is also enforced.
- Generation surpluses or deficits are determined for each intra-area jurisdiction. Because each jurisdiction other than New Brunswick (NB) is only connected to NB, these surpluses and deficits can be transferred to New Brunswick.
- Surpluses transferred to NB from another intra-area jurisdiction are limited by the export limit of the jurisdiction.
- Deficits in an intra-area jurisdiction other than NB that exceed the import capability from NB results in a loss of load event. Otherwise, the deficit is transferred to NB.
- With all transfer-limited intra-area surpluses and deficits transferred to NB, it is determined whether or not the simulated generation in NB plus transferred surpluses is adequate to supply both the NB load and any transferred deficits. If not, then a loss of load event occurs.
- The Monte Carlo simulation is performed for each daily peak hour of the year, and the yearly simulation is repeated 100,000 times to calculate the average LOLE in days/year.

The base load shape for the program is system hourly net loads for each jurisdiction comprising the Area. Monthly load shapes for the individual jurisdictions are created by scaling the hourly loads to match the load forecast values of both demand and energy. This method preserves the effects of load chronology as well as load coincidence between the jurisdictions. This method is also identical between the new program and the old program. A separate monthly load shape comprising only the peak load of each day is created for the LOLE analysis.

To test the 2007 modifications, the Monte Carlo simulation was validated for single areas by comparing its results with the previously benchmarked LOLP program. The multi-area performance of the new program was verified on simplified systems whereby the LOLE results could be calculated by hand and compared with the program calculations.