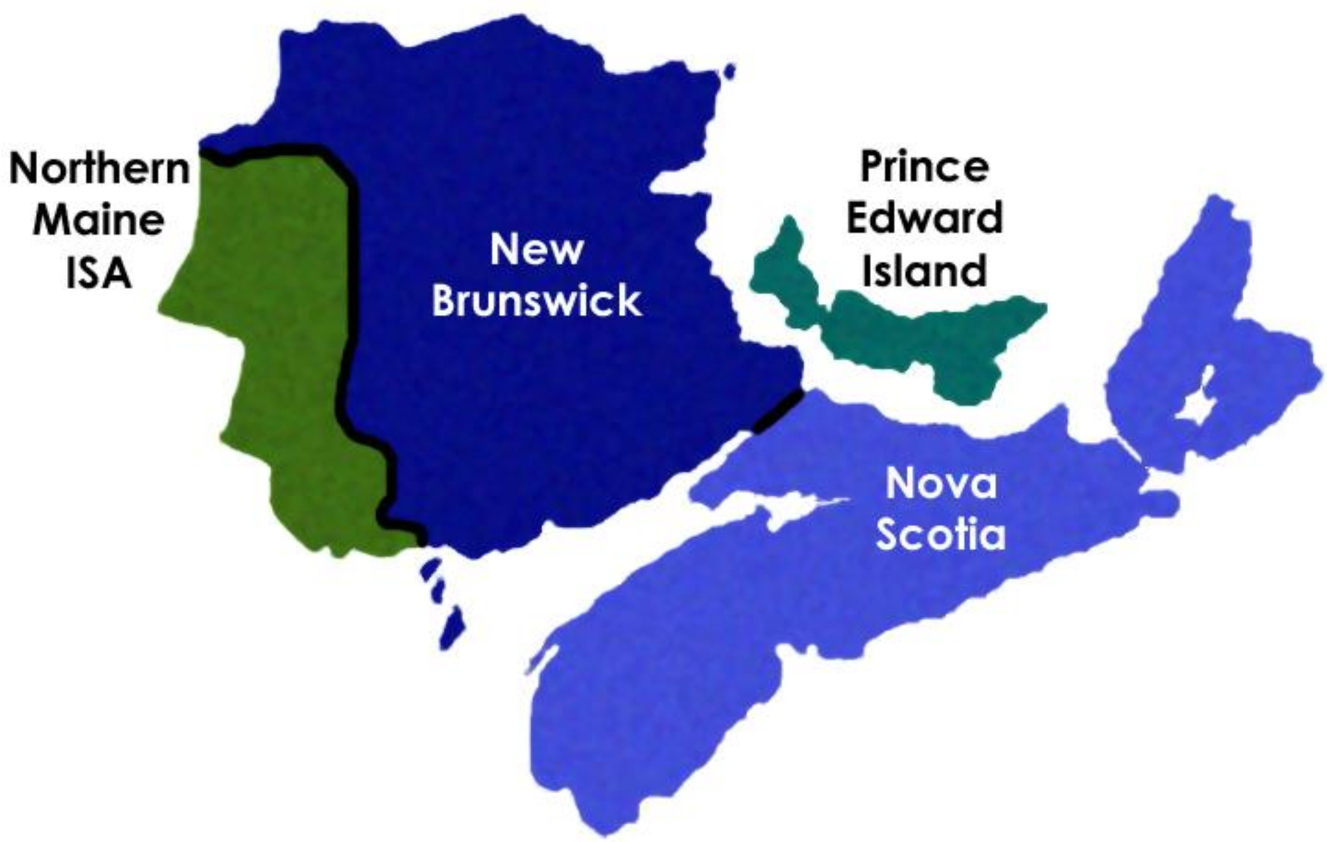
NPCC
2016 MARITIMES AREA COMPREHENSIVE REVIEW OF RESOURCE ADEQUACY

Approved by RCC December 6, 2016



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

September 2016

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EXECUTIVE SUMMARY

The 2016 Maritimes Area Comprehensive Review of Resource Adequacy, covering the period of January 2017 through December 2021, 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 (Approved: September 30, 2015)*. This review supplants the previous Comprehensive Review that was performed in 2013 and approved by the RCC on December 3, 2013.

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	2016 (all jurisdictions)
Load Shape	2011/12 (all years)
Resource Adequacy Criterion	Loss of Load Expectation not more than 0.1 days/year
Maritimes Required Reserve	20% of peak firm load
Interconnection Benefits	300 MW
Area Purchases/Sales	Sales of 200 MW and 114 MW during the 2016/17 and 2018/19 winter peak periods respectively
Maritime Link Project	153 MW of purchases from Newfoundland to Nova Scotia is forecast for mid-2020 coincident with a planned retirement of a 153 MW Nova Scotia generator
RESULTS	
Year	**Expected Number of Firm Load Disconnections days/year**
2017	0.003
2018	0.003
2019	0.003
2020	0.003
2021	0.004

The 2017 coincident peak demand forecast for the Maritimes Area is 5,392 MW, which is 125 MW above the 5,267 MW peak demand forecast in the 2013 Comprehensive Review. This increased peak demand forecast reflects increases in electric heating loads which are not quite offset by declines in industrial loads and demand shifting programs. The average annual demand growth over the 2017–2021 study period of this review is 0.16%, which is marginally higher than the -0.05% annual demand growth forecast in the 2013 review but still essentially flat.

The reserve criterion for the Maritimes Area is 20%, and adherence to this criterion is demonstrated in Section 2.4 to comply with the NPCC resource adequacy criterion.

The NPCC resource adequacy criterion of a Loss of Load Expectation (LOLE) of not more than 0.1 days per year of firm load disconnections is not exceeded by the Maritimes Area for all years covered by this review and varies between 0.003 to 0.004 days/year for the base load forecast. The Maritimes Area is also shown to adhere to its own 20% reserve criterion in all years for the base load forecast, with minimum reserve levels varying between 40% and 44%.

Sensitivity analyses were run to determine the LOLE effects of high load growth, zero wind generation, and removing all external tie benefits. The sensitivity results are shown in Table 2 and meet the NPCC resource adequacy criterion in all years.

Table 2: Summary of LOLE Results

Year	Base Case LOLE	High Load Growth LOLE	Zero Wind LOLE	No Tie Benefits LOLE
	days/year	days/year	days/year	days/year
2017	0.003	0.003	0.017	0.005
2018	0.003	0.003	0.012	0.003
2019	0.003	0.006	0.016	0.004
2020	0.003	0.010	0.019	0.004
2021	0.004	0.019	0.026	0.005

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1.0 INTRODUCTION

The 2016 Maritimes Area Comprehensive Review of Resource Adequacy, covering the period of January 2017 through December 2021, 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 (Approved: September 30, 2015)*. This review supplants the previous Comprehensive Review that was performed in 2013 and approved by the RCC on December 3, 2013.

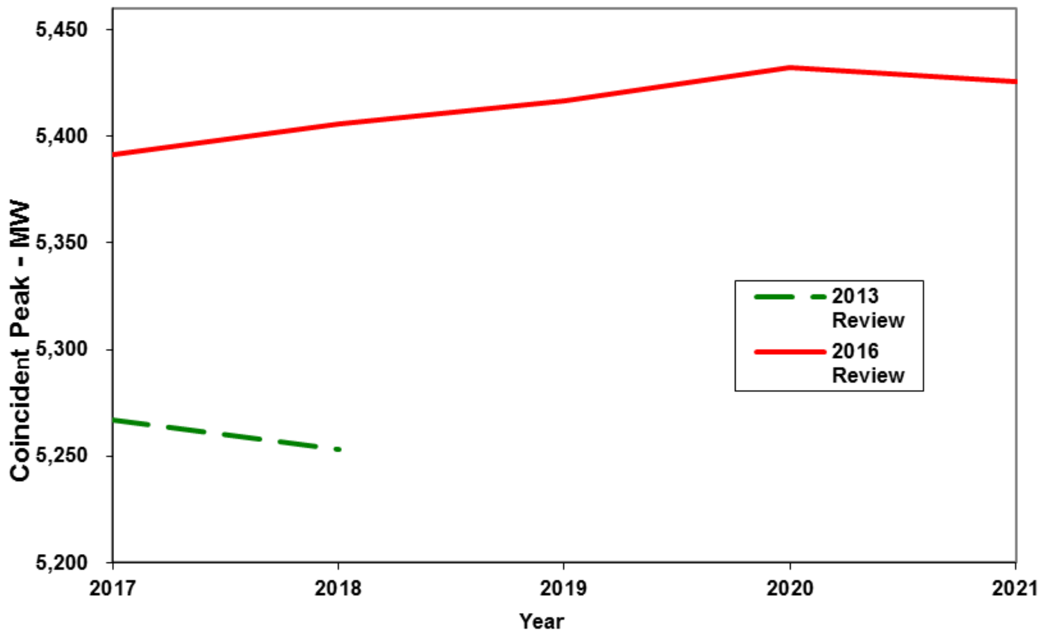
The Maritimes Area is a winter peaking area with separate jurisdictions and regulators in New Brunswick, Nova Scotia, Prince Edward Island (PEI), and Northern Maine. New Brunswick Power (NB Power) is the Reliability Coordinator for the Maritimes Area.

Table 3 and Figure 1 provide a comparison of the load forecasts in the 2016 and 2013 reviews. The coincident peak demand forecast for 2017 is 5,392 MW, which is 125 MW above the 5,267 MW forecast in the 2013 Comprehensive Review. This increased peak demand forecast reflects increases in electric heating demands which were not offset by declines in industrial loads and demand shifting programs. Demand shifting and energy efficiency programs are expected to reduce peak demand in the Maritimes Area by 100 MW to 280 MW during the Comprehensive Review period. The average annual demand growth over the period of this review is 0.16%, which is marginally higher than the 0.05% average demand growth forecast in the 2013 review but still essentially flat.

Table 3: Comparison of Load Forecasts

Winter Peak (Month of January)	2016 Review MW	2013 Review MW
2017	5,392	5,267
2018	5,406	5,253
2019	5,416	N/A
2020	5,432	N/A
2021	5,426	N/A
Five Year Period	**2017–2021**	**2014–2018**
Annual Average Growth Rate	0.16%	0.05%

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, PEI and Northern Maine individually apply a capacity based criterion in determining their required reserves.

New Brunswick, Nova Scotia, and Northern Maine each plan for a reserve equal to greater of the capacity of the largest generator or 20% of the firm load. For this review, the latter criterion was applicable in all years. 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 size of PEI compared to the rest of the Maritimes Area. Thermal and hydro generators are considered available at the Dependable Maximum Net Capability (DMNC) in the determination of the reserve margin.

The NPCC resource adequacy criterion (from *NPCC Directory #1 Design and Operation of the Bulk Power System, Requirement 4 (Dated: September 30, 2015*) states:

> "**R4** Each Planning Coordinator or Resource Planner shall probabilistically evaluate resource adequacy of its Planning Coordinator Area portion of the bulk power

system to demonstrate that the loss of load expectation (LOLE) of disconnecting firm load due to resource deficiencies is, on average, no more than 0.1 days per year.

R4.1 Make due allowances 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.

Actions taken by the Energy Coordinator/Dispatcher, when faced with a developing or sudden capacity shortage, are based upon a number of possible actions best suited to the prevailing system conditions. In practice, the corrective actions 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. Appeal to the public for voluntary customer load reduction.

12. 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 and 11 are valid, the level of assistance available from these procedures is not modeled in this study.

2.3 Maritimes Area Required Reserve

The Maritimes Area employs a reserve criterion of 20% of firm load. The required installed reserve is shown in Section 3.1.

2.4 Relationship of Reserve Criterion to NPCC Reliability Criterion

To relate the Maritimes Area reserve criterion of 20% to the NPCC resource adequacy criterion as stated in Section 2.1, LOLE was evaluated with the Maritimes Area firm load scaled so that the reserve was equal to 20%. The results showed that a Maritimes Area reserve of 20% corresponds to an LOLE of approximately 0.086 days per year. At this load level, only 30 MW of additional load was required to match the NPCC LOLE resource adequacy criterion of 0.1 days per year.

The preceding demonstrates that the 20% Maritimes Area reserve criterion correlates closely with the 0.1 days/year NPCC LOLE resource adequacy criterion.

2.5 Recent Reliability Studies

Resource Planners 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 results presented in this review are based upon an evaluation conducted during the third quarter of 2016 for the period 2017 through 2021. This review supplants the previous Comprehensive Review that was performed in 2013 and approved by the RCC on December 3, 2013. Interim reviews of resource adequacy for the Maritimes Area were completed in the years 2014 and 2015 covering the years 2015–2018 and 2016–2018 respectively. The results of the interim reviews for the two overlapping years 2017 and 2018 compare well with the results of this review. The NPCC resource adequacy criterion was met in both years for all base and sensitivity cases. The same is true for this review.

2.6 Load Forecast Uncertainty

To determine load forecast uncertainty (LFU) an analysis of the historical load forecasts 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 (one or two standard deviations) respectively. The reliability analysis was repeated for these two load models.

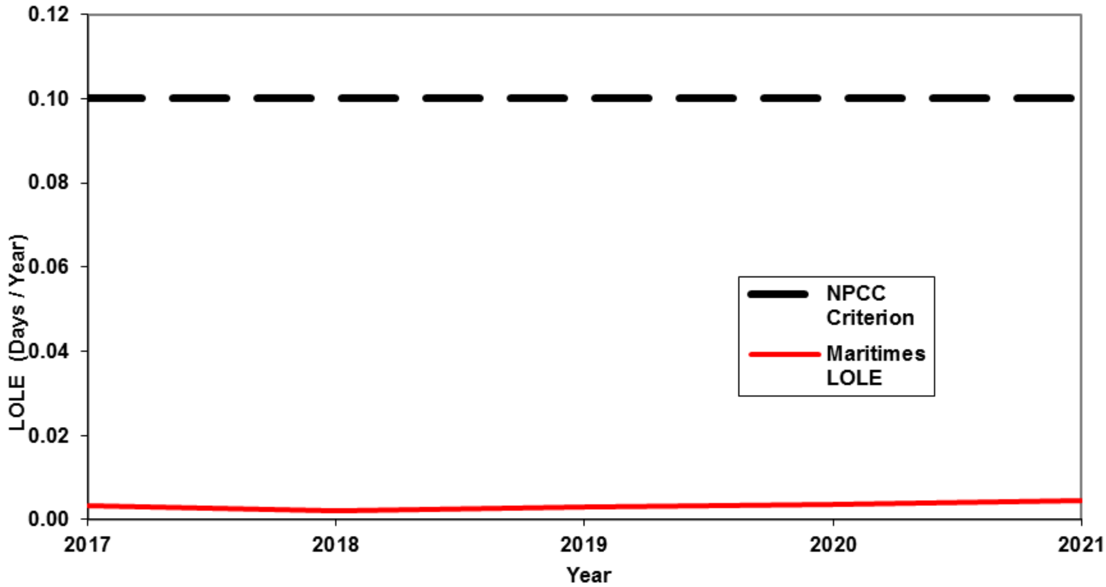
It is assumed that the forecast error is approximately normally distributed around the forecast value and that the contribution to system LOLE is negligible when loads are less than the forecast value by more than ½ a standard deviation. These assumptions result in weighting factors of 0.383, 0.242, 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 meets the NPCC resource adequacy criterion of no more than 0.1 days/year from 2017 to 2021.

Table 4: LOLE days/year – Base Case with Load Forecast Uncertainty

Calendar Year	Expected Number of Firm Load Disconnections days/year
2017	0.003
2018	0.003
2019	0.003
2020	0.003
2021	0.004

Figure 2: LOLE (days/year) – Base Case with Load Forecast Uncertainty



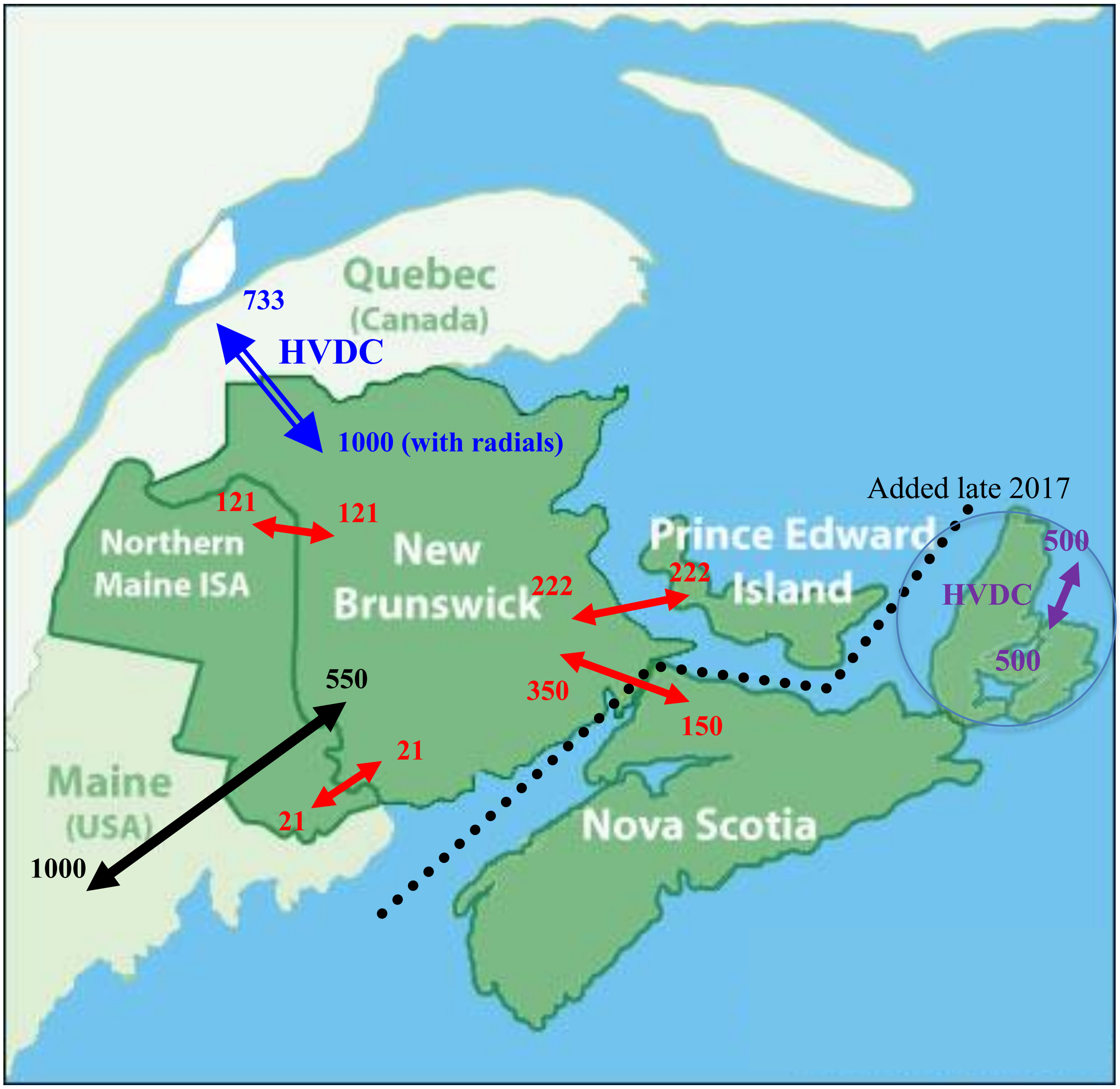
2.7 Intra-Area Transmission Capacity Limits

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 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 (two 138 kV, two 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 operating modes. This effectively allows a high enough transfer limit from New Brunswick to meet the peak load in Northern Maine.

Late in 2016, PEI is installing two additional undersea cables between that province and New Brunswick. Based on a tripling of cable capacity and two additional parallel paths, the single cable contingency limiting flows from PEI to NB has been eliminated. For this review, the transmission limit for this return path was assumed to equal the transmission limit in the NB to PEI direction and as a result the PEI to NB limit was increased from 124 MW to 222 MW. This change has a negligible effect on the Maritimes Area LOLE values since there is little need for PEI capacity to supply NB loads given the high amount of reserve capacity available to NB from other resources.

Figure 3: Maritimes Area Transmission Capacity Limits



3.0 RESOURCE ADEQUACY ASSESSMENT

3.1 Comparison of Forecast and Required Reserve – Base Case

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

Table 5 and Figure 4 represent the results of the reserve comparison for the base load forecast. The forecast reserve levels reflect reserves calculated using wind generation levels at the hour of the Maritimes Area coincident peak demand. In 2017, the wind generation modeled on peak was 496 MW. Based on the wind and load shapes modeled, the minimum hourly reserve expected during 2017 is 1993 MW coinciding with a total Maritimes Area wind generation of 83 MW. In each year of the analysis, the forecast reserve is greater than the required reserve.

Table 5: Forecast, Minimum, and Required Reserve Levels – Base Case

Month Of January	Forecast Capacity	Coincident Peak Load	Inter. Load	Forecast Reserve		Minimum Hourly Reserve		Required Reserve	
	MW	MW	MW	MW	%	MW	%	MW	%
2017	7,207	5,392	268	2,083	41	1,993	41	1,025	20
2018	7,418	5,406	272	2,284	44	2,173	44	1,027	20
2019	7,299	5,416	272	2,154	42	2,021	40	1,029	20
2020	7,454	5,432	272	2,293	44	2,159	43	1,032	20
2021	7,454	5,426	272	2,300	45	2,153	43	1,031	20

$$\text{Forecast Reserve (\%)} = \frac{[\text{Forecast Capacity} - (\text{Peak Load} - \text{Inter. Load})]}{(\text{Peak Load} - \text{Inter. Load})} * 100\%$$

$$\text{Minimum Reserve (\%)} = \frac{\text{Min. of Hourly }[\text{Capacity} - (\text{Load} - \text{Inter. Load})]}{(\text{Load} - \text{Inter. Load})} * 100\%$$

3.2 LOLE results – High Load Growth

Table 6 and Figure 4 illustrate LOLE results if the average annual growth rate is 1% higher than forecast (i.e. 1.16% per year versus 0.16% per year compounded over the 4 year period of this review). The results show that the NPCC resource adequacy criterion is met in all years.

Table 6: Loads and LOLE Results – High Load Growth

Month Of January	High Load Growth Load	Base Case Load	Difference	High Load Growth LOLE	Base Case LOLE
	MW	MW	MW	days/year	days/year
2017	5,392	5,392	0	0.003	0.003
2018	5,454	5,406	48	0.003	0.003
2019	5,517	5,416	101	0.006	0.003
2020	5,581	5,432	149	0.010	0.003
2021	5,645	5,426	220	0.019	0.004

3.3 LOLE Results – Zero Wind

The Maritimes Area did not assign a fixed capacity credit to wind generation. Instead, simulated hourly wind capacity values were netted against corresponding hourly load values. Because there were no wind generation additions beyond 2017 and because the peak load day for the five years did not vary during the 2017 to 2021 period of this review, simulated wind capacity during peak demand was constant at 496 MW compared to an installed total of 974 MW. A sensitivity analysis was performed with the wind capacity on the system set to zero output for all hours. Table 7 and Figure 4 illustrate LOLE results for the zero wind generation scenarios. The results show that Maritimes Area is not reliant on wind capacity to meet the NPCC resource adequacy criterion.

Table 7: Capacity and LOLE Results – Zero Wind

Month Of January	Zero Wind Capacity	Base Case Capacity	Difference	Zero Wind Capacity LOLE	Base Case LOLE
	MW	MW	MW	days/year	days/year
2017	6,711	7,207	-496	0.017	0.003
2018	6,922	7,418	-496	0.012	0.003
2019	6,803	7,299	-496	0.016	0.003
2020	6,958	7,454	-496	0.019	0.003
2021	6,958	7,454	-496	0.026	0.004

3.4 LOLE Results – No Tie Benefits

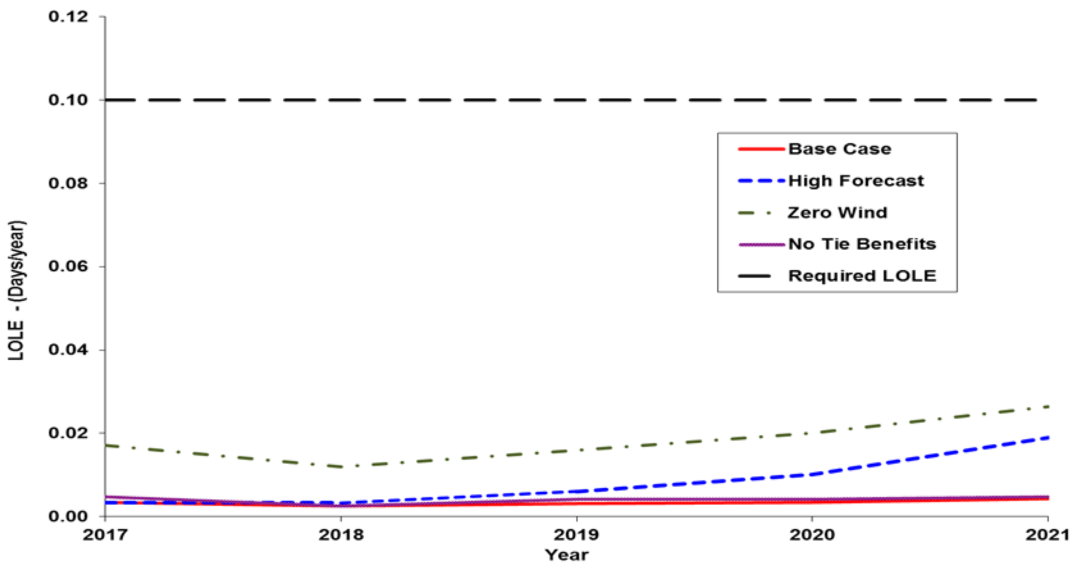
Since 2011, NBSO has assumed 300 MW of tie benefits to New Brunswick in its resource adequacy assessments. These tie benefits are based on a 2011 decision by the New Brunswick Market Advisory Committee to recognize the lowest historical Firm Transmission Capacity posted from summer peaking New England to winter peaking New Brunswick since the commissioning of the second 345 kV tie between these systems in December 2007. To the extent that future capacity purchases from New England to New Brunswick occur across this interface, these tie benefits will be reduced accordingly. Tie benefits from other neighbouring jurisdictions were not considered by the New Brunswick Market Advisory Committee because they also experience peak loads in winter.

In the CP-8 report *Review of Interconnection Assistance Reliability Benefits (December 31, 2015, Approved by RCC March 2, 2016)* the "As Is" estimated tie benefit potential for the Maritimes Area is 702 MW and 1012 MW for the years 2016 and 2020 with an export of 200 MW modeled in both test years. Based on this study, the 300 MW of tie benefits assumed for this 2016 Comprehensive Review is conservative. A sensitivity analysis performed for this review shows that the Area does not require interconnection assistance to meet the NPCC resource adequacy criterion. The results are shown in Table 8 and Figure 4.

Table 8: Capacity and LOLE Results – No Tie Benefits

Month Of January	No Tie Benefits Capacity	Base Case Capacity	Difference	No Tie Benefits LOLE	Base Case LOLE
	MW	MW	MW	days/year	days/year
2017	6,907	7,207	-300	0.005	0.003
2018	7,118	7,418	-300	0.003	0.003
2019	6,999	7,299	-300	0.004	0.003
2020	7,154	7,454	-300	0.004	0.003
2021	7,154	7,454	-300	0.005	0.004

Figure 4: LOLE Results – All Base and Sensitivity Cases



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 FORECAST RESOURCE CAPACITY MIX

4.1 Forecast Resource Capacity Mix

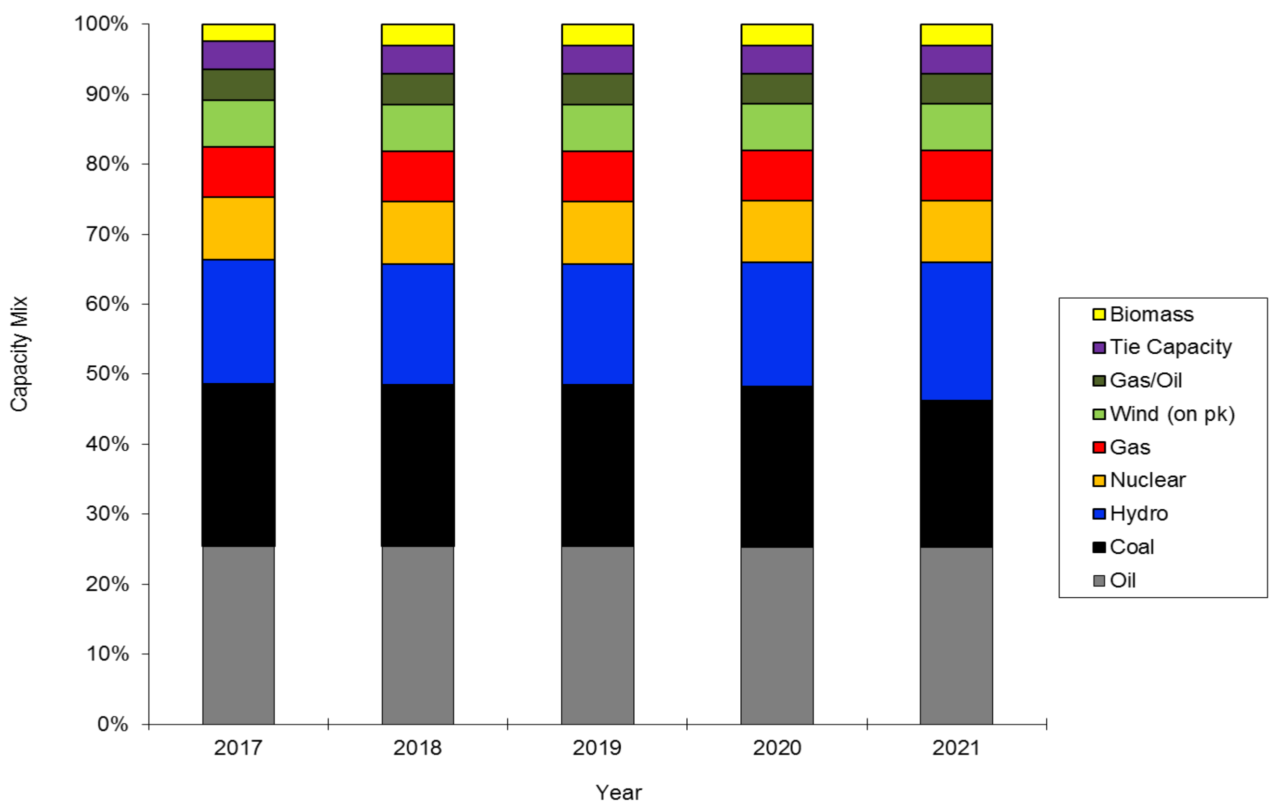
Table 9 and Figure 5 illustrate the forecast resource capacity mix for the Maritimes Area. Appendix A, Section 1.2, Table A-2 presents a detailed list of all capacity resources for the Maritimes Area.

Table 9: Forecast Capacity Resource Mix

Month of January	Oil	Coal	Hydro	Nuclear	Gas	Wind*	Gas/Oil	Tie Benefits	Biomass
	%	%	%	%	%	%	%	%	%
2017	25	23	18	9	7	7	4	4	2
2018	25	23	17	9	7	7	4	4	3
2019	25	23	17	9	7	7	4	4	3
2020	25	23	18	9	7	7	4	4	3
2021	25	21	20	9	7	7	4	4	3

* Wind capacity based on 496 MW of wind capacity (out of 974 MW installed) during coincident peak

Figure 5: Forecast Capacity Resource mix



4.2 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. This resource diversification also provides flexibility to respond to any future environmental issues, such as potential restrictions to greenhouse gas emissions. The Renewable Energy Standard in Nova Scotia calls for 25% of energy sales to be supplied from renewable resources in 2016 and increases to 40% in 2020. The increase in renewable requirements in 2020 will largely be met by the import of hydro energy from Newfoundland and Labrador and will result in reduced fossil fuel generation.

APPENDIX A - DESCRIPTION OF RESOURCE RELIABILITY MODEL

DESCRIPTION OF RESOURCE RELIABILITY MODEL

1.0 Load Model

1.1 Fiscal year 2011/12 hourly system load data for the Maritimes Area utilities was used as the load shape for this study. Demand and energy forecasts for 2017 to 2021 inclusive were prepared by each resource planner. The combined load and energy forecasts for the Maritimes Area are 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**
2017	5392	5181	4821	3946	3463	3222	3228	3145	3217	3672	4412	4894	5392
2018	5406	5193	4845	3952	3471	3228	3248	3170	3235	3689	4432	4924	5406
2019	5416	5200	4863	3981	3517	3275	3266	3183	3257	3707	4456	4947	5416
2020	5432	5214	4879	3989	3517	3271	3262	3188	3254	3702	4457	4956	5432
2021	5426	5220	4883	3974	3517	3269	3270	3190	3259	3703	4452	4961	5426
ENERGY GWh													
Year	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**	**Total**
2017	3018	2719	2702	2251	2029	1859	1935	1950	1874	2085	2359	2843	27622
2018	3042	2738	2728	2279	2058	1882	1955	1969	1894	2105	2381	2866	27897
2019	3067	2762	2742	2294	2077	1900	1961	1971	1898	2111	2390	2874	28047
2020	3077	2774	2756	2306	2081	1905	1964	1978	1902	2115	2396	2884	28138
2021	3078	2775	2758	2300	2081	1906	1965	1979	1903	2118	2393	2882	28138
INTERRUPTIBLE DEMAND MW													
Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	On Peak
2017	268	258	343	342	324	352	366	360	365	344	346	266	268
2018	272	262	348	347	329	352	366	360	365	345	346	267	272
2019	272	263	348	348	329	353	366	360	365	345	346	267	272
2020	272	263	348	347	329	352	366	360	365	345	346	267	272
2021	272	263	348	347	328	352	366	360	365	344	346	267	272

Note: The forecast coincident peak demand occurs in January.

1.2 Load forecast uncertainty (LFU) was considered in the analysis as described in Section 2.6 of the main report.

1.3 Some entities within the Maritimes Area supply a portion of their own electricity demand and energy requirements. Only the portions that are supplied by the Maritimes Area utilities were 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 2017–2021 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 Dependable 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 tested annually, reaching a minimum of 95% of their declared capabilities for at least 1 full hour. This conforms to NPCC unit testing standard Directory #9 Verification of Generator Gross and Net Real Power Capability. Nova Scotia Power, Inc. (NSPI) reviews generator capability ratings at three year intervals and assumes successful verification at a minimum 98% of the declared value for at least one consecutive hour. This also conforms to the requirements outlined in NPCC Directory #9.

Table A-2: Maritimes Area Resources

New Brunswick Resources				
Plant	**Unit**	**Type**	**Capacity MW**	**Notes**
Point Lepreau	1	Nuclear	660	
		Diesel	5	
Belledune	2	Coal	466	
Coleson Cove	1	Oil	324	
	2	Oil	324	
	3	Oil	324	
Bayside	6	Natural Gas	290	Capacity (Combined Cycle Operation)
Grand Manan	3	Diesel	28	
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
Grandview	1	Natural Gas	49	Summer Capacity = 43 MW
	2	Natural Gas	49	Summer Capacity = 43 MW
NUG Purchases		Biomass	38	
		Hydro	15	
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	41	
Grand Falls	1	Hydro	16	
	2	Hydro	16	
	3	Hydro	16	
	4	Hydro	16	
Tobique	1	Hydro	10	
	2	Hydro	10	
Nepisiguit Falls	1	Hydro	11	
Sisson	1	Hydro	9	
Milltown	1	Hydro	4	
Purchases/Sales (+/-)			-200	Firm Sale for January 2017
Tie Benefits			300	
NB Wind	All	Wind	120	Expected during peak (294 MW installed)
TOTAL CAPACITY			4174	Total Capacity as of January 2017

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

Nova Scotia Resources				
Plant	**Unit**	**Type**	**Capacity MW**	**Notes**
Lingan	1	Coal	153	
	2	Coal	153	Assumed retirement mid-2020
	3	Coal	153	
	4	Coal	153	
Trenton	5	Coal	150	Summer Capacity = 135 MW
	6	Coal	157	
Pt. Tupper	2	Coal	152	
Tufts Cove	1	Gas/Oil	81	
	2	Gas/Oil	93	
	3	Gas/Oil	147	
	4	Natural Gas	49	Summer Capacity = 47 MW
	5	Natural Gas	49	Summer capacity = 47 MW
	6	Natural Gas	49	
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
NUG Purchases	All	Biomass/hydro	27.8	
PH Biomass		Biomass	0	Energy only during 2017
COMFIT Biomass	All	Biomass	25	
Wreck Cove	1	Hydro	105	
	2	Hydro	105	
Annapolis		Hydro	4	
Avon		Hydro	7	
Black River		Hydro	23	
Nictuax		Hydro	8	
Lequille		Hydro	13	
Paradise		Hydro	5	
Mersey		Hydro	43	
Sissiboo		Hydro	27	
Bear River		Hydro	11	
Tusket		Hydro	2	
St. Margarets		Hydro	11	
Sheet Harbour		Hydro	11	
Dickie Brook		Hydro	2	
Fall River		Hydro	1	
Other small hydro	All	Hydro	0.7	
NALCOR Firm Contract		Hydro	0	Expected mid-2020
NS Wind	All	Wind	238	Expected during peak (434 MW installed excluding 164 MW of energy only resources)
TOTAL CAPACITY			2601.5	Total Capacity as of January 2017

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

Prince Edward Island Resources				
Plant	**Unit**	**Type**	**Capacity MW**	**Notes**
Charlottetown	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	1	Diesel	2	Owned by the City of Summerside
	2	Diesel	2	
	3	Diesel	2	
	5	Diesel	2	
	6	Diesel	1	
	7	Diesel	1	
	8	Diesel	4	
PEI Wind	All	Wind	103	Expected during peak (204 MW installed)
TOTAL CAPACITY			261	Total Capacity as of January 2014

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

Northern Maine Resources				
Plant	**Unit**	**Type**	**Capacity MW**	**Notes**
Tinker	1-5	Hydro	35	
		Diesel	1	
Fort Fairfield		Wood	33	
Ashland		Wood	37	
Caribou		Hydro	1	
		Diesel	7	
Squa Pan		Hydro	1	
EMEC		Black Liquor/ Biomass/ Natural Gas	20	
NMISA Wind	All	Wind	35	Expected during peak (42 MW installed)
TOTAL CAPACITY			170	Total Capacity as of January 2014

Table A-3: Summary of Changes in Modeled Capacity

Year	Capacity in January MW	Capacity in December MW	January to January Capacity Change MW	January to December Capacity Change MW	Explanation -Total Capacities include tie benefits (MW) and the impact of firm purchases and/or sales and planned maintenance
2017	7,207	7,407	0	+200	Removal of 200 MW sale after January,
2018	7,418	7,340	+211	-78	For January; -36 MW removal of generator for maintenance until April, +45 MW of formerly transmission constrained biomass capacity, and +2 MW of biomass capacity. For December; +36 MW for return of unit under maintenance in April, -114 MW sale in December
2019	7,299	7,454	-119	-155	For January; -41 MW removal of generator for maintenance until April. For December; +114 MW removal of sale after January +41 MW for return of unit under maintenance in April
2020	7,454	7,454	+155	0	-153 MW of coal capacity in mid-2020 offset by +153 MW of hydro based capacity purchases
2021	7,454	7,454	0	0	No changes

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 three year calculations using the Derating Adjusted Forced Outage Rate (DAFOR) methodology in IEEE Standard 762-2006, Section 8.17.4.

NSPI also uses three year average DAFOR calculations for forced outage rates consistent with 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 (%)	
	2016 Review	2013 Review
Oil	0 - 10	1 – 10
Coal	1 – 10*	2 –16*
Hydro	0 - 5	1 – 11**
Nuclear	7	6
Natural Gas	0 - 7	1 – 7
Wind	0	0
Oil/Gas	6 - 9	6 – 8
Biomass	2 - 8	1 – 8

* A single coal unit dropped from 16 % to 10 % during the period 2013 to 2016. The remaining coal units were less than 4% for the 2016 review and 7% for the 2013 review.

** One hydro plant had a forced outage rate as high as 11%. Its power house was flooded during an extreme weather event in 2011. All other hydro generators had forced outage rates of 1%.

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 generators from the model at their retirement date. The only known retirement assumed during the 2017 to 2021 period of this review is the mid-2020 retirement of the Lingan 2 unit in Nova Scotia. Reliability impacts will be negligible as the retirement is to be simultaneously offset by a similar sized hydro based firm capacity purchase.

3.0 Representation of Interconnected Systems

Since 2011, NB Power has assumed 300 MW of tie benefits to New Brunswick in its resource adequacy assessments. These tie benefits are based on a 2011 decision by the New Brunswick Market Advisory Committee to recognize the lowest historical Firm Transmission Capacity posted from summer peaking New England to winter peaking New Brunswick since the commissioning of the second 345 kV tie between these systems in December 2007. To the extent that future capacity purchases from New England to New Brunswick occur across this interface, these tie benefits will be reduced accordingly. Tie benefits from other neighbouring jurisdictions that are also winter peaking are not considered.

In the CP-8 report Review of Interconnection Assistance Reliability Benefits (December 31, 2015, Approved by RCC March 2, 2016) the "As Is" estimated tie benefit potential for the Maritimes Area is 702 MW to 1012 MW for the years 2016 and 2020 with an export of 200 MW modeled in both test years. Based on this study, the 300 MW of tie benefits assumed for this 2016 Comprehensive Review is conservative.

4.0 Modeling of Variable and Limited Energy Sources

Wind resources are modeled as simulated hourly values that are netted out against the hourly loads. The hourly wind shapes are based upon historical hourly wind generation values for the 2011-2012 fiscal year. New wind capacity forecast for a Maritimes Area jurisdiction is modeled by scaling the historical wind generation in that jurisdiction.

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 of the main report). 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 sub-area is included in their respective forecasts and in the combined Maritimes Area forecast in Table A-1.

6.0 Modeling of Non-Utility Generation

Certain 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. In addition to these NUG units, a Nova Scotia's Community Fit (COMFIT) program generators are also non-utility generators. Some 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 and air pollutants are in place for the 2020-2030 timeframe in Nova Scotia. These regulations specify multi-year hard caps rather than annual limits which provide for some flexibility in the operation of the fleet over the specified compliance periods. 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 during summer 2016.

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. In the case of wind generation, hourly wind generation generation projections for the time of the Area coincident peak are netted against the loads. 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.