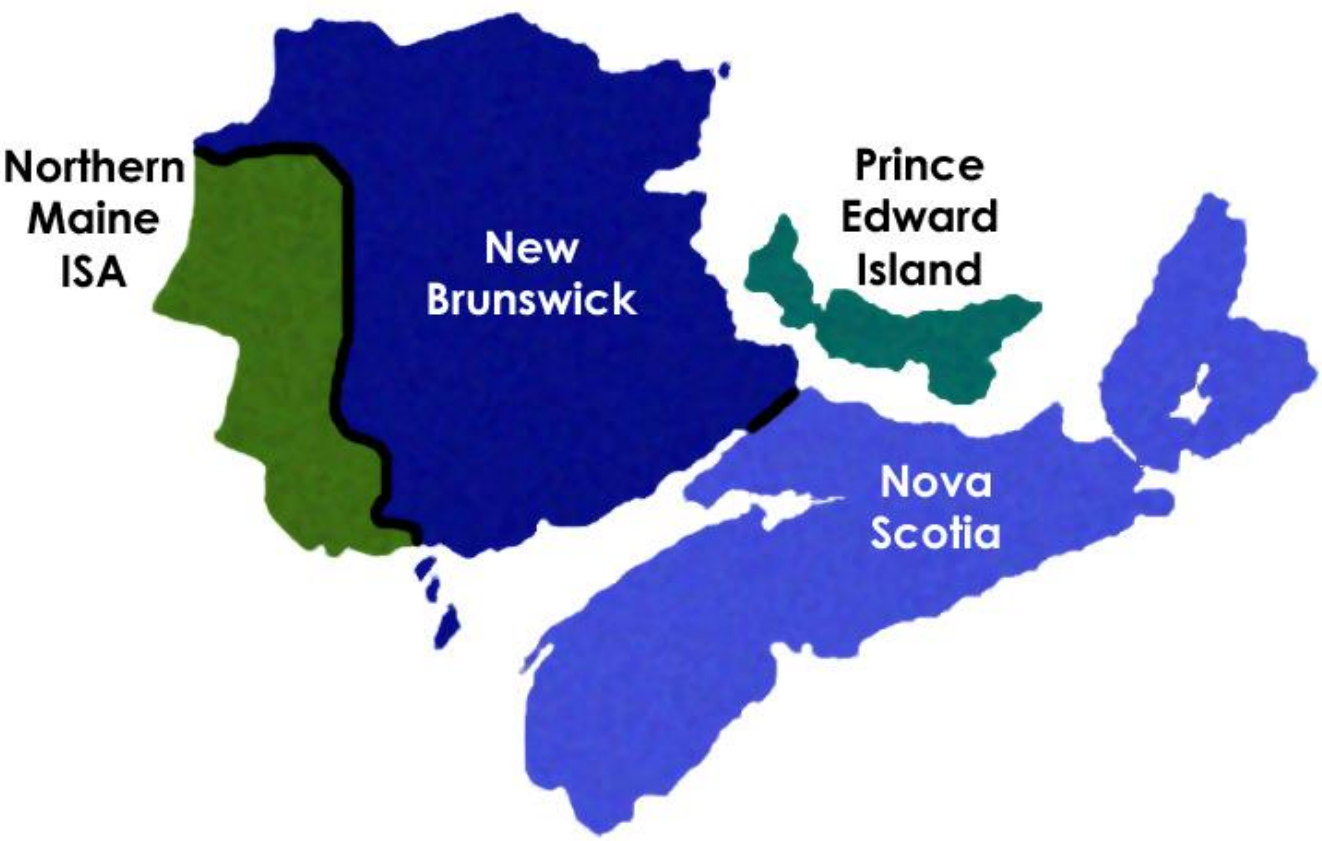
**Approved by the RCC December 3, 2013**

# NPCC
# 2013 MARITIMES AREA
# COMPREHENSIVE REVIEW OF RESOURCE ADEQUACY





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


**September 2013**

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## EXECUTIVE SUMMARY

The 2013 Maritimes Area Comprehensive Review of Resource Adequacy, covering the period of January 2014 through December 2018, 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 2010 and approved by the RCC on September 9, 2010.

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 | 2013 (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 |
| NB to NS tie capability | Reduced from 300 MW to 150 MW |
| Maritime Link project | 153 MW of purchases from Newfoundland to Nova Scotia is forecast for Jan. 1, 2018 coincident with an assumed retirement of a 153 MW Nova Scotia generator |
| **RESULTS** | |
| **Year** | **Expected Number of Firm Load Disconnections days/year** |
| 2014 | 0.012 |
| 2015 | 0.011 |
| 2016 | 0.007 |
| 2017 | 0.006 |
| 2018 | 0.005 |

The 2014 coincident peak demand forecast for the Maritimes Area is 5,242 MW, which is 183 MW below the 5,425 MW peak demand forecast in the 2010 review. This reduced peak demand forecast reflects load decreases in mining, forestry and pulp and paper industries, slower customer load growth in reaction to higher charges for electricity, and energy efficiency programs. The average annual demand growth over the 2014–2018 study period of this review is 0.05%, which is higher than the -0.01% annual demand growth forecast in the 2010 review.

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

Beginning with the 2011 Maritimes Area Interim Review of Resouce Adequacy, tie capability from NB to NS was reduced from 300MW to 150 MW to account for increased southeastern NB loads.

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 0.005 to 0.012 days/yr 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 45% and 46%.

Sensitivity analyses were run to determine the effects of high load growth, zero wind generation, and removing all external tie benefits on LOLE. 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 |
| 2014 | 0.012 | 0.012 | 0.049 | 0.013 |
| 2015 | 0.011 | 0.012 | 0.058 | 0.012 |
| 2016 | 0.007 | 0.011 | 0.038 | 0.007 |
| 2017 | 0.006 | 0.014 | 0.036 | 0.006 |
| 2018 | 0.005 | 0.016 | 0.028 | 0.005 |

Beginning October 1, 2013, the New Brunswick System Opertor will be amalgamated with New Brunswick Power Corporation. This restructuring will have no impact on the reliability of the Maritimes Area.

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## 1.0 INTRODUCTION

The 2013 Maritimes Area Comprehensive Review of Resource Adequacy, covering the period of January 2014 through December 2018, 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 2010 and approved by the RCC on September 9, 2010.

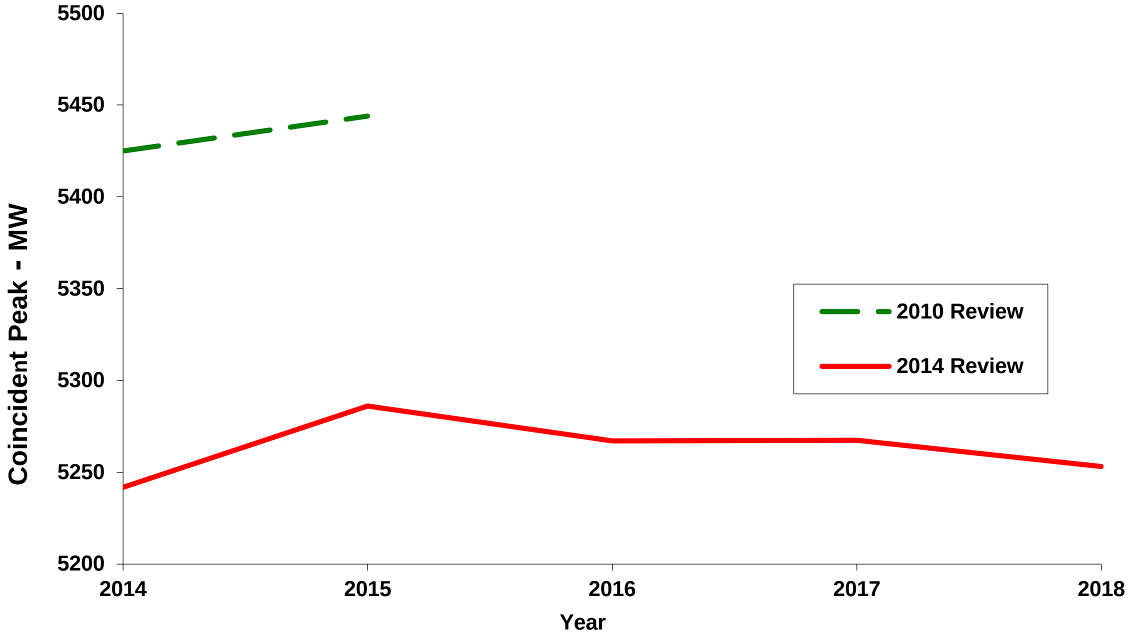
The Maritimes Area is a winter peaking area with separate jurisdictions and regulators in New Brunswick, Nova Scotia, Prince Edward Island (PEI), and Northern Maine. The New Brunswick System Operator (NBSO) is the Reliability Coordinator for the Maritimes Area. Beginning October 1, 2013, NBSO will be amalgamated with the New Brunswick Power Corporation (NB Power). This restructuring will have no impact on the reliability of the Maritimes Area.

Table 3 and Figure 1 provide a comparison of the load forecasts in the 2013 and 2010 reviews. The coincident peak demand forecast for 2014 is 5,242 MW, which is 183 MW below the 5,425 MW forecast in the 2010 Comprehensive Review. This reduced peak demand forecast reflects load decreases in mining, forestry and pulp and paper industries, slower customer load growth in reaction to higher charges for electricity, and energy efficiency programs. The average annual demand growth over the period of this review is 0.05%, which is higher than the -0.01% average demand growth forecast in the 2010 review.

**Table 3: Comparison of Load Forecasts**

| Winter Peak (Month of January) | 2013 Review MW | 2010 Review MW |
|---|---|---|
| 2014 | 5,242 | 5,425 |
| 2015 | 5,286 | 5,444 |
| 2016 | 5,267 | N/A |
| 2017 | 5,267 | N/A |
| 2018 | 5,253 | N/A |
| **Five Year Period** | **2014 – 2018** | **2011 – 2015** |
| **Annual Average Growth Rate** | 0.05% | -0.01% |

**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 PEI 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 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, Section 5.2 (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. 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 0.096 days per year. An additional 10 MW of load was required to establish an LOLE of 0.1 days per year.

The preceding leads to the conclusion that the Maritimes Area reserve criterion meets the NPCC resource adequacy criterion.

## 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 results presented in this review are based upon an evaluation conducted during the third quarter of 2013 for the period 2014 through 2018. This review supplants the previous Comprehensive Review that was performed in 2010 and approved by the RCC on September 9, 2010. Interim reviews of resource adequacy for the Maritimes Area were completed in the years 2011 and 2012 covering the years 2012–2015 and 2013–2015 respectively. The results of the interim reviews for the two overlapping years 2014 and 2015 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.

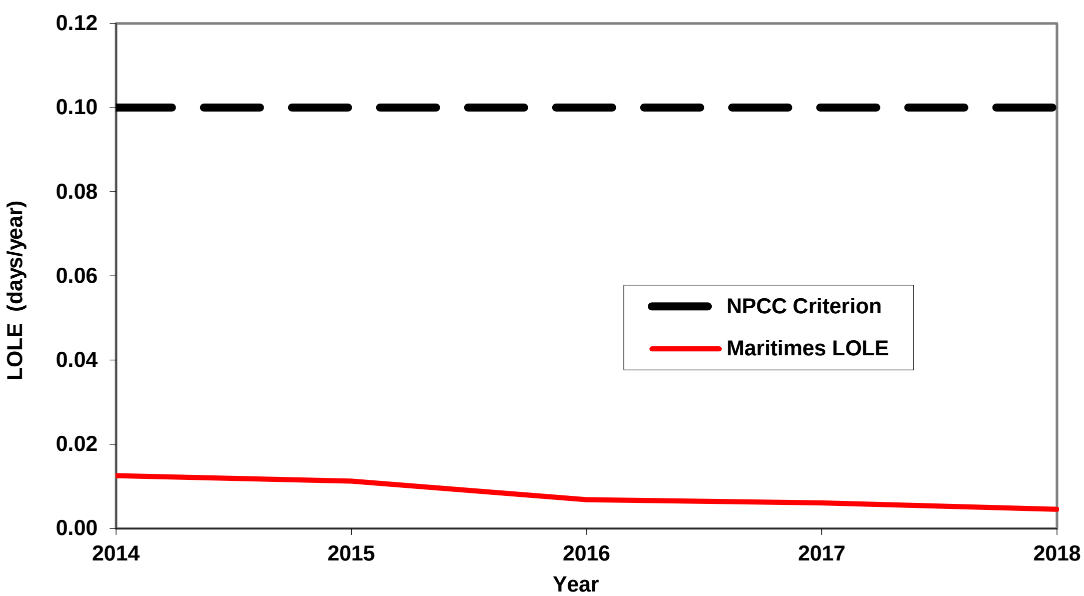
It is assumed that the forecast error is approximately normally distributed around the forecast value and that the contribution to system LOLE is negligible when loads are less than the forecast value by more than ½ a standard deviation. These assumptions result in weighting factors of 0.383, 0.242, 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 2014 to 2018.

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

| Calendar Year | Expected Number of Firm Load Disconnections days/year |
|---|---|
| 2014 | 0.012 |
| 2015 | 0.011 |
| 2016 | 0.007 |
| 2017 | 0.006 |
| 2018 | 0.005 |

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



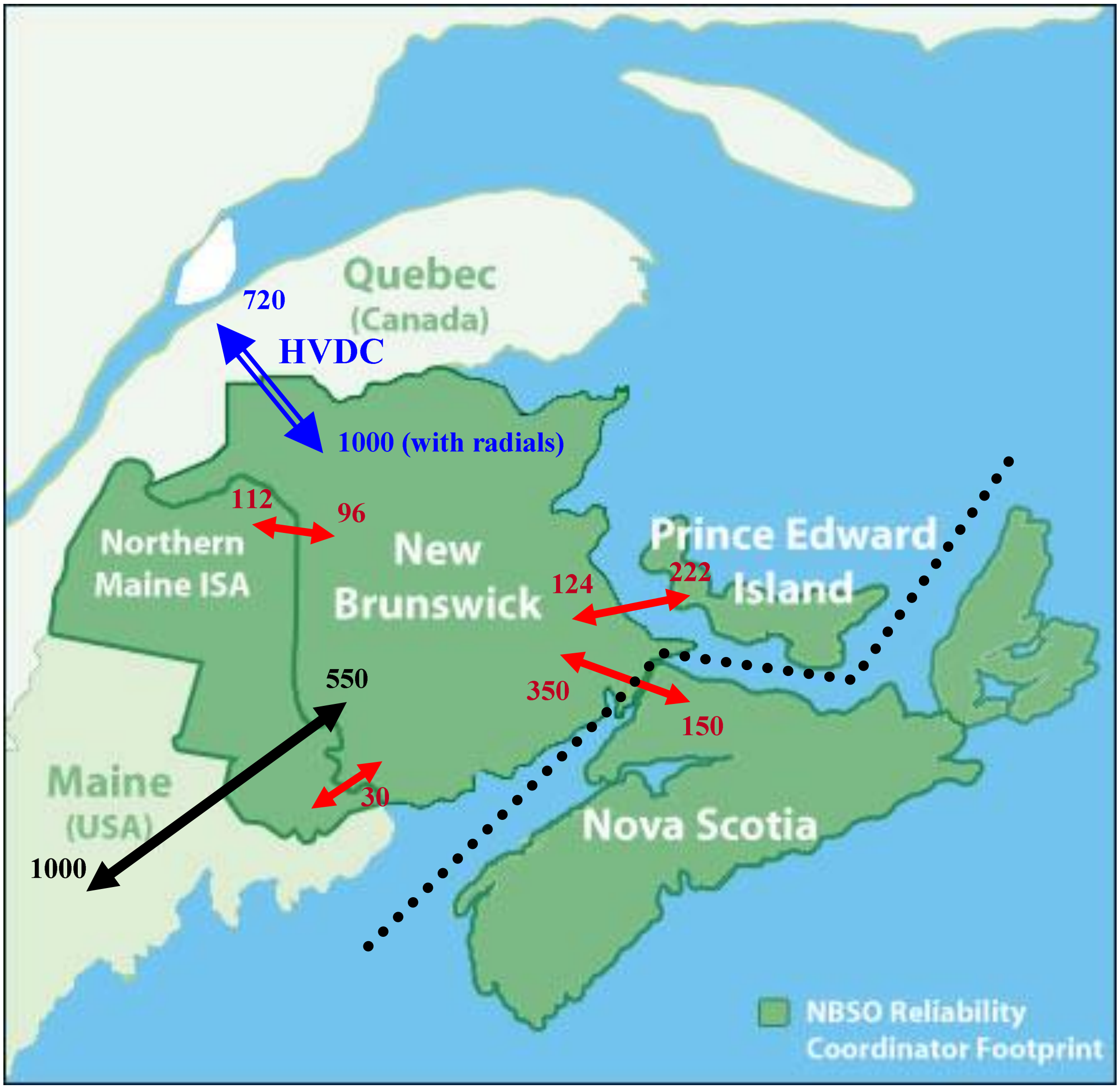
## 2.7 Intra-Area Transmission Capacity Limits

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 results occurs for only one of these three interconnections, the tie between New Brunswick and Nova Scotia.

Beginning with the 2011 Maritimes Area Interim Review of Resource Adequacy, tie capacity from NB to NS was reduced from 300 MW to 150 MW to account for increased southeastern NB loads.

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.

**Figure 3: Maritimes 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 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 2014, the wind generation modelled on peak was 449 MW. Based on the wind and load shapes modelled, the minimum hourly reserve expected during 2014 is 2170 MW coinciding with wind generation of 203 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 | % |
| 2014 | 7,274 | 5,242 | 250 | 2,282 | 46 | 2,170 | 45 | 998 | 20 |
| 2015 | 7,347 | 5,286 | 251 | 2,312 | 46 | 2,173 | 45 | 1,007 | 20 |
| 2016 | 7,390 | 5,267 | 250 | 2,373 | 47 | 2,215 | 45 | 1,003 | 20 |
| 2017 | 7,403 | 5,267 | 251 | 2,387 | 48 | 2,211 | 45 | 1,003 | 20 |
| 2018 | 7,417 | 5,253 | 251 | 2,415 | 48 | 2,223 | 46 | 1,000 | 20 |

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

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

### 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. 1.05% per year versus 0.05% per year). 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 |
| 2014 | 5,242 | 5,242 | 0 | 0.012 | 0.012 |
| 2015 | 5,297 | 5,286 | 11 | 0.012 | 0.011 |
| 2016 | 5,353 | 5,267 | 86 | 0.011 | 0.007 |
| 2017 | 5,409 | 5,267 | 142 | 0.014 | 0.006 |
| 2018 | 5,466 | 5,253 | 213 | 0.016 | 0.005 |

### 3.3 LOLE Results – Zero Wind

In a change from the 2010 review, the Maritimes Area no longer assigns a fixed capacity credit to wind generation. Instead, simulated hourly wind capacity values were netted against corresponding hourly load values. Simulated wind capacity during peak demand varies between 449 MW and 559 MW for the 2014 to 2018 period of this review. 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 |
| 2014 | 6,825 | 7,274 | -449 | 0.049 | 0.012 |
| 2015 | 6,825 | 7,347 | -522 | 0.058 | 0.011 |
| 2016 | 6,858 | 7,390 | -532 | 0.038 | 0.007 |
| 2017 | 6,858 | 7,403 | -545 | 0.036 | 0.006 |
| 2018 | 6,858 | 7,417 | -559 | 0.028 | 0.005 |

### 3.4 LOLE Results – No Tie Benefits

In the 2010 Comprehensive Review, zero interconnection tie benefits were assumed. Since 2011, NBSO has assumed 300 MW of tie benefits to New

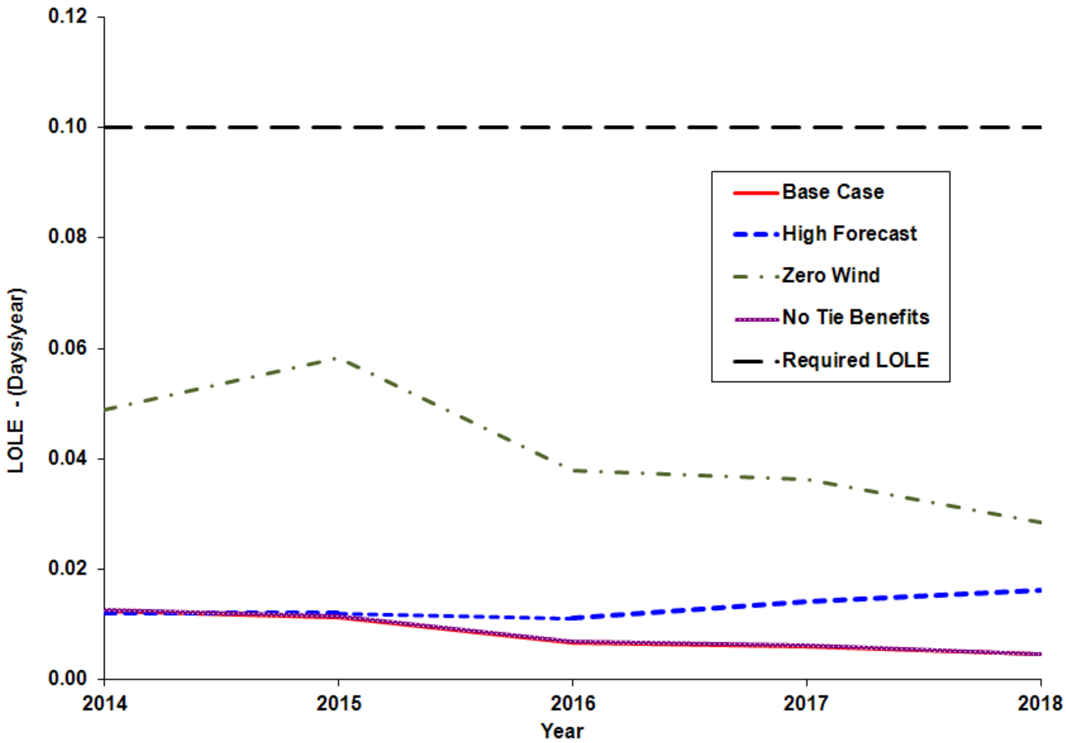
Brunswick in its resource adequacy assessments. These tie benefits are on a 2011 decision by the New Brunswick Market Advisory Committee to recognize the lowest historical Firm Transmission Capacity posted from summer peaking New England to winter peaking New Brunswick since the commissioning of the 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 (June 1, 2011)* the range of estimated annual tie benefit potential for the Maritimes Area for 2011 was 1076 – 1353 MW and 1,252 and 1,536 MW in the year 2015. Based on this study, the 300 MW of tie benefits assumed for this 2013 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.

**Table 8: Capacity and LOLE Results – No Tie Benefits**

| Month Of January | No Tie Benefits Capacity | BaseCase Capacity | Difference | No Tie Benefits LOLE | Base Case LOLE |
|---|---|---|---|---|---|
| | MW | MW | MW | days/year | days/year |
| 2014 | 6,974 | 7,274 | -300 | 0.013 | 0.012 |
| 2015 | 7,047 | 7,347 | -300 | 0.012 | 0.011 |
| 2016 | 7,090 | 7,390 | -300 | 0.007 | 0.007 |
| 2017 | 7,103 | 7,403 | -300 | 0.006 | 0.006 |
| 2018 | 7,117 | 7,417 | -300 | 0.005 | 0.005 |

**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.

## 3.6 Proposed Changes to Market Rules

On October 19, 2011 the New Brunswick government released its new energy blueprint, a three year energy strategy aimed at reducing and stabilizing energy prices, providing energy security, ensuring reliability of the electrical system, environmental responsibility, and providing effective regulation. The plan will amalgamate the NB Power group of companies and the New Brunswick System Operator into a single vertically integrated Crown utility as of October 1, 2013. This restructuring will have no impact on the reliability of the Maritimes Area.

## 4.0 FORECAST RESOURCE CAPACITY MIX

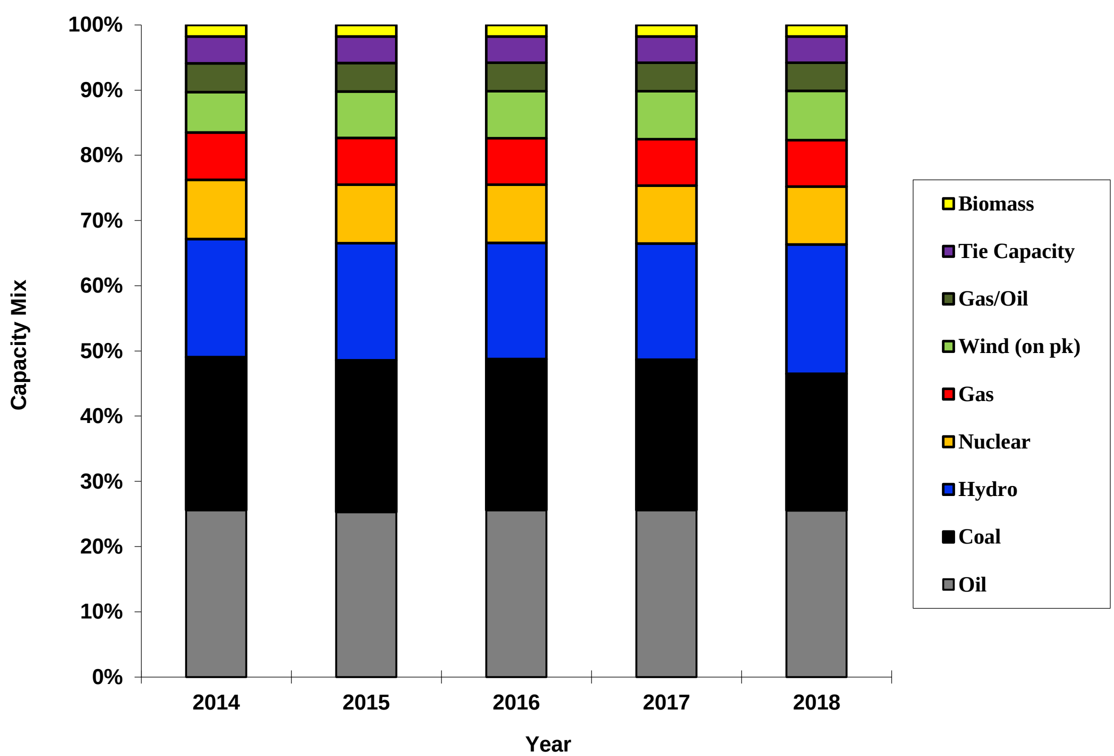
### 4.1 Forecast Resource Capacity Mix

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 |
|---|---|---|---|---|---|---|---|---|---|
| | % | % | % | % | % | % | % | % | % |
| 2014 | 26 | 23 | 18 | 9 | 7 | 6 | 4 | 4 | 2 |
| 2015 | 25 | 23 | 18 | 9 | 7 | 7 | 4 | 4 | 2 |
| 2016 | 26 | 23 | 18 | 9 | 7 | 7 | 4 | 4 | 2 |
| 2017 | 26 | 23 | 18 | 9 | 7 | 7 | 4 | 4 | 2 |
| 2018 | 26 | 21 | 20 | 9 | 7 | 8 | 4 | 4 | 2 |

**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.

# APPENDIX A DESCRIPTION OF RESOURCE RELIABILITY MODEL

## DESCRIPTION OF RESOURCE RELIABILITY MODEL

### 1.0 Load Model

1.1 Fiscal year 2011/2012 hourly system load data for the Maritimes Area utilities was used as the load shape for this study. Demand and energy forecasts for 2014 to 2018 inclusive were prepared by each system operator. 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** |
| 2014 | 5242 | 5132 | 4750 | 3938 | 3655 | 3248 | 3243 | 3227 | 3274 | 3606 | 4458 | 4759 | 5242 |
| 2015 | 5286 | 5183 | 4785 | 3968 | 3668 | 3279 | 3261 | 3249 | 3292 | 3615 | 4482 | 4780 | 5286 |
| 2016 | 5267 | 5179 | 4768 | 3967 | 3671 | 3281 | 3253 | 3246 | 3289 | 3615 | 4475 | 4780 | 5267 |
| 2017 | 5267 | 5163 | 4758 | 3968 | 3664 | 3271 | 3253 | 3242 | 3292 | 3604 | 4467 | 4778 | 5267 |
| 2018 | 5253 | 5174 | 4765 | 3950 | 3655 | 3291 | 3263 | 3258 | 3298 | 3597 | 4430 | 4743 | 5253 |
| **ENERGY GWh** | | | | | | | | | | | | | |
| **Year** | **Jan** | **Feb** | **Mar** | **Apr** | **May** | **Jun** | **Jul** | **Aug** | **Sep** | **Oct** | **Nov** | **Dec** | **Total** |
| 2014 | 2930 | 2648 | 2621 | 2223 | 2045 | 1862 | 1929 | 1917 | 1872 | 2106 | 2336 | 2780 | 27269 |
| 2015 | 2960 | 2676 | 2644 | 2241 | 2057 | 1881 | 1939 | 1928 | 1883 | 2114 | 2347 | 2791 | 27462 |
| 2016 | 2956 | 2672 | 2636 | 2242 | 2057 | 1883 | 1938 | 1927 | 1885 | 2116 | 2344 | 2792 | 27448 |
| 2017 | 2959 | 2672 | 2635 | 2243 | 2055 | 1883 | 1939 | 1926 | 1884 | 2115 | 2344 | 2791 | 27447 |
| 2018 | 2957 | 2673 | 2645 | 2243 | 2058 | 1888 | 1941 | 1933 | 1889 | 2117 | 2344 | 2786 | 27474 |
| **INTERRUPTIBLE DEMAND MW** | | | | | | | | | | | | | |
| **Year** | **Jan** | **Feb** | **Mar** | **Apr** | **May** | **Jun** | **Jul** | **Aug** | **Sep** | **Oct** | **Nov** | **Dec** | **On Peak** |
| 2014 | 250 | 245 | 370 | 379 | 371 | 383 | 405 | 395 | 395 | 371 | 381 | 253 | 250 |
| 2015 | 251 | 245 | 370 | 379 | 371 | 383 | 405 | 395 | 395 | 371 | 381 | 253 | 251 |
| 2016 | 250 | 245 | 369 | 378 | 370 | 382 | 404 | 394 | 394 | 370 | 380 | 253 | 250 |
| 2017 | 251 | 245 | 369 | 378 | 370 | 381 | 403 | 393 | 393 | 369 | 379 | 253 | 251 |
| 2018 | 251 | 246 | 369 | 377 | 370 | 381 | 402 | 393 | 393 | 369 | 379 | 253 | 251 |

Note: The forecast coincident peak demand occurs in January.

1.2 Load forecast uncertainty (LFU) was considered in the analysis as described in Section 2.5 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 2014 – 2018 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) also 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 one percent of two hour generator outputs.

## 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 | 467 | |
| Coleson Cove | 1 | Oil | 324 | |
| | 2 | Oil | 324 | |
| | 3 | Oil | 324 | |
| Bayside | 6 | Natural Gas | 290 | Capacity (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 |
| NUG Purchases | | Biomass/Hydro | 55 | |
| 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 | |
| Sisson | 1 | Hydro | 9 | |
| Milltown | 1 | Hydro | 3 | |
| Nepisiguit Falls | 1 | Hydro | 11 | |
| NB Wind | All | Wind | 120 | Expected on during peak out of 294 MW installed |
| Tie Benefits | | | 300 | |
| **TOTAL CAPACITY** | | | **4369** | Total Capacity as of January 2014 |

## 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 | |
| Lingan | 1 | Coal | 153 | |
| | 2 | Coal | 153 | Assumed retirement January 1, 2018 |
| | 3 | Coal | 153 | |
| | 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 | 0 | 33 MW Currently unavailable, assumed return to service March 2015 |
| 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 | 105 | |
| | 2 | Hydro | 105 | |
| Annapolis | | Hydro | 4 | |
| Avon | | Hydro | 7 | |
| Black River | | Hydro | 23 | |
| Nictuax | | Hydro | 8 | |
| Lequille | | Hydro | 11 | |
| Paradise | | Hydro | 5 | |
| Mersey | | Hydro | 43 | |
| 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 | |
| NUG Purchases | All | Biomass/Hydro | 28 | |
| Small Biomass | | | 10 | |
| PH Biomass | | Biomass | 0 | 53 MW - Energy only unit |
| NS Wind Projects | All | Wind | 191 | Expected on during peak out of 349 MW installed |
| **TOTAL CAPACITY** | | | **2507** | Total Capacity as of January 2014 |

## 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 | 13 | Owned by the City of Summerside |
| PEI Wind | All | Wind | 103 | Expected on during peak out of 204 MW installed |
| **TOTAL CAPACITY** | | | **265** | Total Capacity as of January 2014 |

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

| Northern Maine Resources | | | | |
|---|---|---|---|---|
| **Plant** | **Unit** | **Type** | **Capacity MW** | **Notes** |
| Tinker | | Hydro | 35 | |
| | | Diesel | 1 | |
| Caribou Oil | | Oil | 22 | |
| Caribou | | Diesel | 7 | |
| | | Hydro | 1 | |
| Boralex – Ashland (FF) | | Wood | 33 | |
| Squa Pan | | Hydro | 1 | |
| EMEC | | | 20 | |
| NMISA Wind | All | Wind | 35 | Expected on during peak out of 42 MW installed |
| **TOTAL CAPACITY** | | | 133 | Total Capacity as of January 2014 |

**Table A - 3: Summary of Changes in Capacity**

| Year | January Capacity MW | December Capacity MW | Year over Year Capacity Change MW | Explanation<br><br>-Total Capacities include tie benefits (MW)<br>-All wind capacity expected on peak (MW) |
|---|---|---|---|---|
| 2014 | 7,307 | 7,380 | +73 | NS Wind (+73 MW on peak, +133 MW installed) |
| 2015 | 7,380 | 7,390 | +10 | NS Wind (+10 MW on peak, +17 MW installed) |
| 2016 | 7,390 | 7,403 | +13 | NS Wind (+13 MW on peak, +25 MW installed), |
| 2017 | 7,403 | 7,417 | +14 | NS Wind (+14 MW on peak, +25 MW installed), |
| 2018 | 7,417 | 7417 | 0 | NS Lingan 2 retired -153 MW coal<br>Nfld. to NS purchase +153 MW hydro |

## 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 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 % | |
|---|---|---|
| | 2013 Review | 2010 Review |
| Oil | 1 – 10** | 1 – 10 |
| Coal | 2 –16 | 2 – 4 |
| Hydro | 1 – 11* | 1 – 8 |
| Nuclear | 6 | 4 |
| Natural Gas | 1 – 7 | 2 – 4 |
| Wind (after derating) | 0 | 0 |
| Oil / Gas | 6 – 8 | 2 |
| Biomass | 1 – 8 | 3 |

* Most light oil fueled generators are in the range of 1-5%. Two smaller Combustion turbines and some of the heavy oil fueled generators are in the order of 7-10%.

** One hydro plant (the 4 generator - 64MW Grand Falls plant in NB) had a forced outage rate as high as 11%. Its power house was flooded during an extreme weather event in 2011. All other hydo 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 scheduled during the 2014 to 2018 period of this review is the January 1, 2018 retirement of the Lingan 2 unit in Nova Scotia.

## 3.0 Representation of Interconnected Systems

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 (June 1, 2011)* the range of estimated annual tie benefit potential for the Maritimes Area for 2011 was 1076 – 1353 MW and 1,252 and 1,536 MW in the year 2015. Based on this study, the 300 MW of tie benefits assumed for this 2013 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 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 and air pollutants are expected for the 2020-2030 timeframe and could restrict 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 during summer 2013.

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.