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# Capacity Value of Wind Assumptions and Planning Reserve Margin

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# Executive Summary

Effective Load Carrying Capacity (ELCC), or capacity value, of variable generation and required planning reserve margin are two important input assumptions for the 2014 Integrated Resource Plan (IRP). NS Power has re-examined these input assumptions with the present and future system configurations.

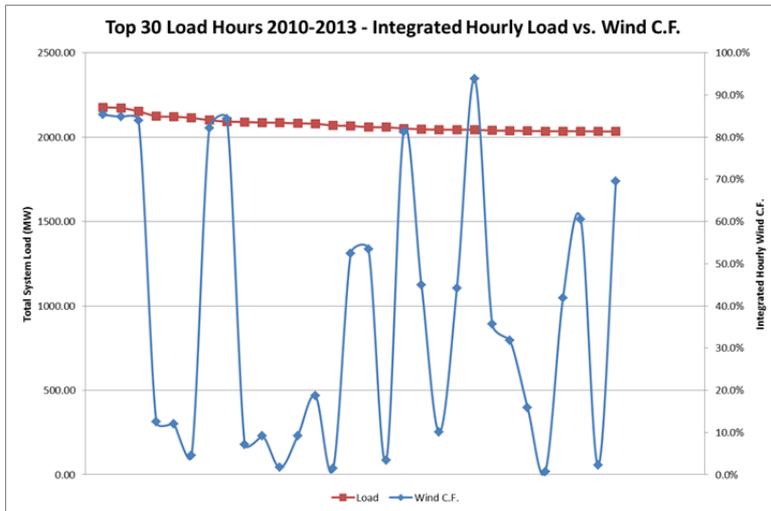
Loss of Load Expectation (LOLE) methodology is an accepted method for the calculation of required planning reserve margin and, in some jurisdictions, ELCC of variable generation. NSPI conducted an LOLE study to confirm the variable energy generation ELCC results in the recent GE Energy integration study.

A cumulative frequency analysis is another accepted method for capacity valuation and this analysis was also conducted using actual historical NSPI data to compare with the results of the LOLE study.

NS Power will test resource plans using wind with capacity values of 12% (from the cumulative distribution analysis) and 27% (from the GE Energy integration study).

# LOLE Study Results

- The required planning reserve margin was confirmed to be 20 percent.
- GE Energy LOLE study concluded that the ELCC of present and committed wind generation on NSPI system could be as high as 27 percent. ELCC estimates in other jurisdictions have typically been between 5 and 20 percent.
- NSPI's LOLE study has largely matched the GE Energy study's calculations.



- However, the LOLE methodology may not be a suitable method to calculate wind generation capacity value on NSPI's system. This is due to the averaging nature of the LOLE methodology and the observed bimodal distribution of wind generation output during peak demand on NSPI's system.
- This figure shows how wind generation falls short during many of the highest system demand hours. Over valuation of wind generation capacity effectively diminishes the planning reserve leaving the system challenged to reliably serve firm peak under high demand conditions.

# Cumulative Distribution Analysis Study Results

A cumulative distribution analysis of actual NSPI wind generation data, consistent with the methodology used in other jurisdictions, i.e. CAISO, BPA, & SPP, shows a significantly lower capacity value for wind generation.

Confidence level	ELCC of Wind Generation
95%	4%
90%	8%
85%	12%
80%	16%

The empirical analysis expresses numerically the actual historical wind generation behaviour described on the previous page.

Accepting a confidence level of 85%, this study indicates that a capacity value of wind should not exceed 12% for planning purposes.

# Effective Load Carrying Capacity of Variable Generation

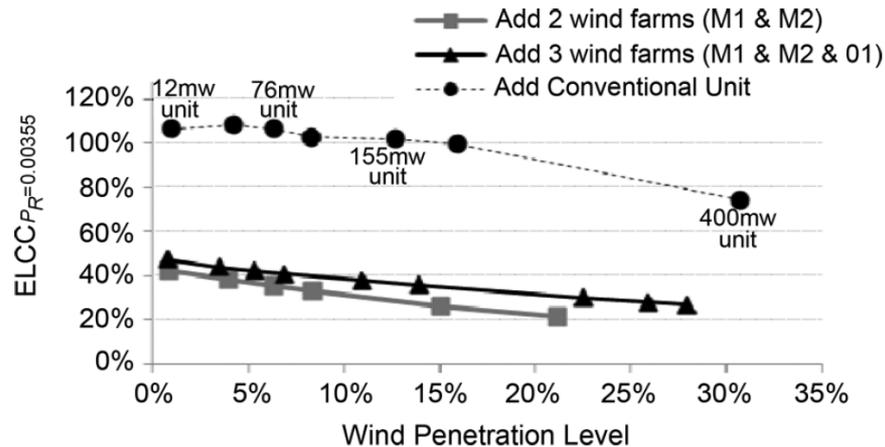
## (LOLE Method)

# Capacity Value of Wind – LOLE method

Effective Load Carrying Capacity (ELCC) of wind calculation was conducted in PLEXOS software using equivalent LOLE with firm energy substitution methodology, which is consistent with the methodology prescribed by the IEEE Task Force on the Capacity Value of Wind Power.

ELCC of wind generation is expected to decrease with increased wind penetration, as in the accrual ELCC example below.

IEEE TRANSACTIONS ON POWER SYSTEMS, VOL. 27, NO. 4, NOVEMBER 2012



# GE Energy LOLE study

GE Energy found that the capacity value of 336 MW of wind generation was 31% or 103 MW, while the capacity value of an incremental 335MW, on top of installed and contracted ~540 MW of wind was 12%, or 40 MW.

Reference: Pages 261-272 of Nova Scotia Renewable Energy Integration Study.

GE reports capacity value of 540 MW of wind to be 27%, or 146 MW, on pg. 266 of the study, fig. 220, which is slightly higher but consistent with NSPI LOLE study findings.

On the same page GE Energy states: *“This is an indication that wind regime in Nova Scotia is well suited to the provincial power needs. Values in the range of 5-20% are more common in the northeast US. “*

It is expected that the discrepancy between the two analyses is the result of the observed bi-modal behaviour of the Nova Scotia wind regime as it relates to power system peak and averaging nature of the LOLE methodology.

# GE Energy LOLE study - Excerpts

The figures below are excerpts from GE Energy’s calculation of ELCC of wind generation. The GE Energy ELCC calculation has a notable excursion from the expected curve slope at about 550 MW of wind which is explained by increasing diversity. *GE Energy Renewable Energy Integration Study, Page 266.*

Table 51: Wind Blocks for Capacity Valuation

Wind Block	Capacity (MW)
Block 1	335.8
Block 2	36.0
Block 3	89.1
Block 4	116.0
Block 5	365.0

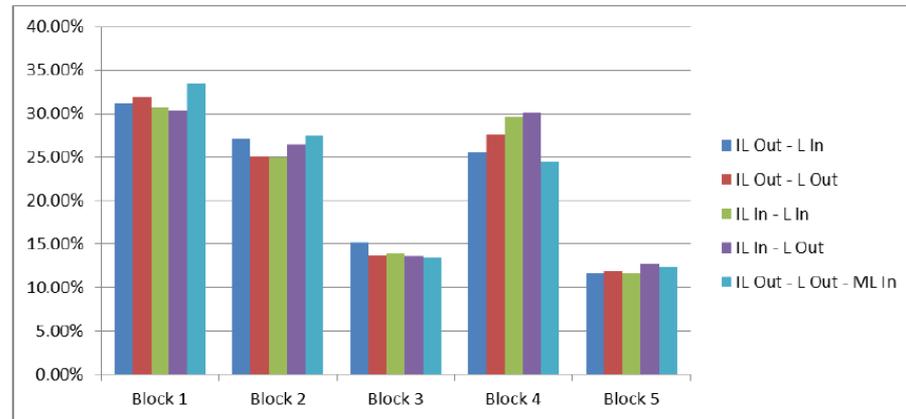


Figure 220: Incremental Capacity Value (%) for all blocks

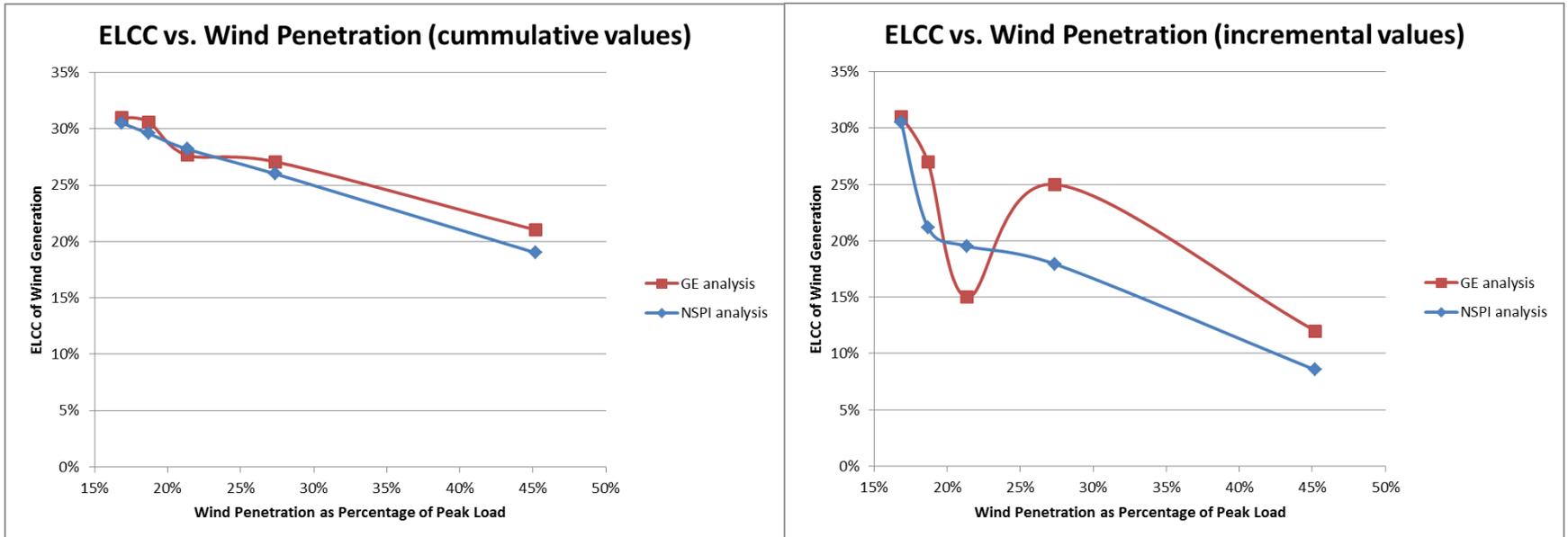
# Capacity Value of Wind – ELCC

Wind penetration level	GE Energy calculated ELCC (Incremental)	NSPI calculated ELCC (Incremental)	GE Energy calculated ELCC (cumulative)	NSPI calculated ELCC (cumulative)
336 MW	31%	30.5%	31.0%	30.5%
372 MW	27%	21.2%	30.6%	29.6%
425 MW	15%	19.5%	27.6%	28.2%
~545 MW	25%	19.9%	27.1%	26%
Need to estimate incremental and cumulative effects for wind penetration between ~545 - ~900 MW				
~900 MW	12%	8.5%	21.0%	19%

Cumulative values of GE Energy incremental ELCC values were calculated using a weighted average with respect to penetration levels.

# Capacity Value of Wind – ELCC

Graphical representation of cumulative and incremental ELCC values for wind generation as calculated by GE Energy and NSPI.



GE Energy ELCC vs. Wind Penetration curve is similar to the one derived by NSPI using similar LOLE methodology.

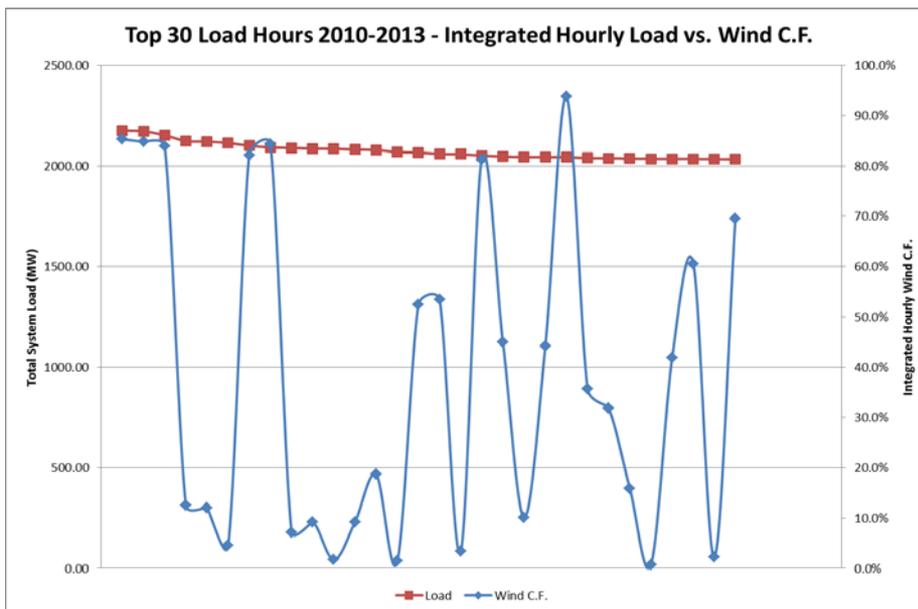
NOTE: The incremental values plot is equivalent to the plot in GE Energy study Figure 220.

# Challenges applying LOLE methodology to NSPI's system

The graph below shows the 30 highest load hours over the past 4 years and the coincident available wind capacity during those hours.

In this plot it can be seen that while wind generation may be present at near nameplate capacity during some high load hours, it may not be there at all in other high load hours. While the hourly capacities shown here may average to a large figure, that ELCC would not adequately represent the true system operating requirements. In fact, in 1/3 of the peak load hours shown

here wind generation is at 10% or less.



This bi-modal wind generation behavior makes the inherent averaging LOLE method of calculating capacity value of wind, with matched load –wind shapes, rather optimistic.

The risk of overstating capacity value of wind is designing a system with inadequate firm capacity to serve load in all peak hours.

# Challenges applying LOLE methodology to NSPI's system

LOLE is inherently an averaging quantity:

$$\text{LOLE} = \text{Average (LOLP)} / 100 * 8784 / 24$$

Where LOLP = Loss of Load Probability

As such LOLE quantity does not adequately preserve the high LOLP values impact on the system. The plot below is an example of the LOLP distribution throughout a year and it



illustrates why averaging of LOLP quantities into an annual LOLE quantity may not be the best method for calculating NSPI's capacity value of wind.

# Effective Load Carrying Capacity of Variable Generation

## Cumulative Frequency Analysis

# Capacity Value of Wind – Empirical Analysis

- Objective: To determine what minimum capacity factor of wind we can predict to be available to the NS Power system, in peak hours, with  $x\%$  certainty
- Methodology: **Cumulative Frequency Analysis** is the technique of analyzing a set of historical data points to see how often a particular value is exceeded
  - Other systems including CAISO, BPA, & SPP use variations on this approach

# Cumulative Frequency Analysis - Procedure

1. Collect as much logged data on wind generation as possible
  - Using data in terms of hourly Capacity Factor allows us to consider a longer history, over which installed wind capacity has grown
2. Assign that data into bin(s) we are interested in
  - Single bin containing the top 10% of load hours
3. Fit a probability distribution to the data
4. Calculate the inverse cumulative probability for the confidence level  $x$ ; this is the value we have  $(1-x)\%$  chance of being less than according to the fitted distribution (and therefore  $x\%$  chance of exceeding)

# Cumulative Frequency Analysis - Data Sources

- Integrated hourly generation (MWh) for the following wind farms (299.6 MW):
  - Covers 94.6% of installed capacity at end of 2013
    - Pubnico
    - Gulliver (Digby)
    - Nuttby
    - Dalhousie
    - Maryvale
    - Glen Dhu
    - Bearhead
    - Lingan
    - Amherst
- Study period was 4 full years 2010-2013
- Data was cleaned to remove commissioning periods
- Any hourly value reported above max station capacity was reduced to that of max capacity

# Cumulative Frequency Analysis – Key Assumptions

- Data within each bin are from a single population
  - No significant differences caused by increased diversity in later years of study period as additional wind farms come online
- Historical performance is representative of our future expectations for wind generation

# Cumulative Frequency Analysis - Results

- Within the top 10% of load hours, 2010-2013:

Confidence level	ELCC of Wind Generation
95%	4%
90%	8%
85%	12%
80%	16%

# Required Planning Reserve Margin

# Required Planning Reserve

Methodology:

1. Wind energy is substituted with firm equivalent generation
2. If LOLE is < 0.1 days per year, firm system demand will be added until LOLE is = 0.1; Total installed capacity minus added load is the required capacity for LOLE of 0.1
3. If LOLE is >0.1 days per year, firm capacity will be added until LOLE = 0.1; Total installed capacity plus added firm capacity is the required capacity for LOLE of 0.1

Planning Reserve Margin = (Required Generation Capacity – Peak Load) / Peak Load

NOTE: If actual wind generation, rather than firm equivalent, was included in the calculation of the planning reserve margin, a decision would have to be made on the capacity value of wind, in order to calculate the required planning reserve for 0.1 LOLE.

As such, the calculation provides the firm planning reserve margin requirement, part of which can be served by wind generation, depending on the calculated capacity value of wind.

# Required Planning Reserve

Planning reserve requirement calculation is based on the NPCC accepted criterion of loss of firm load no more than 1 day in ten years or 0.1 days per year. This means that the system planning reserve is such that it allows the system to fail to meet peak system demand on the average for 2.4 hours every year, on average.

Methodology: Adjust capacity on the system to produce LOLE of 0.1 days per year.

MW	2016	2020	2025
Firm Peak Load Forecast [MW]	2011.2	1991.2	1966.9
Required capacity for 0.1 days LOLE [MW]	2390	2372	2362
Total Planning Reserve Requirement	$(2390-2011.2)/2011.2$ =378.8/2011.2 =18.8%	$(2372-1991.2)/1991.2$ =380.8/1991.2 =19.1%	$(2362-1966.9)/1966.9$ =395.1/1966.9 =20.1%

2016 – no Maritime Link (ML) – no thermal retirements

2020 – with ML both base & supplemental blocks – One Lingan unit retired

2025 – with ML base and no supplemental block – no additional steam retirements

# Study Discussion, Conclusions and Recommendations

# Planning Reserve Margin Risks with Wind Capacity Factor

The cost of under- or over-estimating the capacity value of wind is asymmetrical. Over-estimating the capacity value of wind and then operating the system accordingly could result in inadequate resources to meet peak system demand. That situation has much more severe consequences than under-estimating wind resources capacity and having more than adequate resources to meet peak demands, particularly as NSPI is a winter peaking utility.

There are uncertainties associated with load growth. For example, we have seen the highest system peak firm load in history in January 2014, which adds to the importance of carrying adequate planning reserve margin .

The planning reserve margin can be compromised by assigning a high capacity value to wind generation in the planning process. For example, a 27% capacity value for committed wind generation of 550-600 MW means that ~150-160 MW, or 40% of the required planning reserve, may or may not be available depending on the wind generation output.

Furthermore, there is uncertainty associated with the integration of ~550-600 MW of committed wind capacity on the system from 2016 onward.

# Study Conclusion and Recommendation

The required planning reserve margin was confirmed to be 20%, consistent with the assumption used in previous long term studies.

Due to the nature of wind generation in Nova Scotia, the LOLE averaging methodology may overstate ELCC of wind generation, if a careful examination of risk is not allowed for.

Cumulative frequency analysis of existing wind generation data shows the capacity value of wind generation within specified risk levels and can be used as a qualifier of the LOLE results.

In order to be able to design the system with adequate resources to maintain system reliability, the study indicates an appropriate capacity value for wind resources is 12%, taking into account the empirical data analysis results and a reasonable level of risk.

Even though the LOLE methodology had to be qualified by the empirical analysis in order to determine the absolute ELCC of wind generation, the relative slope of the ELCC vs. Wind Penetration curve can be used to calculate the ELCC of future wind generation additions.

# IRP Wind Capacity Value Assumptions

- For this long term-planning exercise, two different wind capacity value constructs will be used to test Candidate Resource Plans:
  - Existing and incremental values per the GE Study (page 266), 27% cumulative capacity value up to ~545 MW, and lower incremental values beyond 545 MW;
  - 12% capacity value as determined by the cumulative frequency analysis study.

# Appendix 1

## Study Assumptions

# System Assumptions

## REQUIRED SYSTEM ASSUMPTIONS FOR THE LOLE STUDY

- WIND FORECAST / HOURLY WIND SHAPE
- LOAD FORECAST / HOURLY LOAD SHAPE
- UNAVAILABILITY OF VARIABLE GENERATION
- DAFOR (DERATION ADJUSTED FORCED OUTAGE RATE) FORECAST
- CAPACITY ADDITIONS/ RETIREMENTS
- MARITIME LINK AND NB IMPORTS CAPABILITY
- FLEET MAINTENANCE SCHEDULE

# System Assumptions – WIND

## Wind shape:

Use AWS Truepower wind shape, based on 2006 wind speed measurements as provided by GE Energy.

## Wind Forecast:

IRP wind forecast including COMFIT.

## Unavailability of Variable Generation:

Unavailability due to transmission congestion, icing, forced outages, wind over speed, etc... will be represented by a 5% forced outage rate applied to all variable generators. This value is consistent with literature and with common practice among other jurisdictions.

# System Assumptions – SYSTEM DEMAND

System demand without PHP will be used in this study. In order to calculate capacity value of wind and required planning reserve margin, it is irrelevant whether PHP demand is on the system or not. PHP demand is only relevant when calculating absolute system LOLE.

The LOLE study was conducted with 2006 load shape in order to match load to the AWST wind shape which is based on 2006 measurements.

# System Assumptions – CAPACITY

## Deration Adjusted Forced Outage Rate

Use DAFOR based on historical plant performance values for thermal plants.  
Use 5% DAFOR for wind and hydro generation.

### Methodology:

Plexos uses convolution method, as opposed to Monte Carlo Stochastic method, to calculate ELCC of generating units as a part of the LOLP/LOLE indices computation.

## Capacity Additions and Retirements:

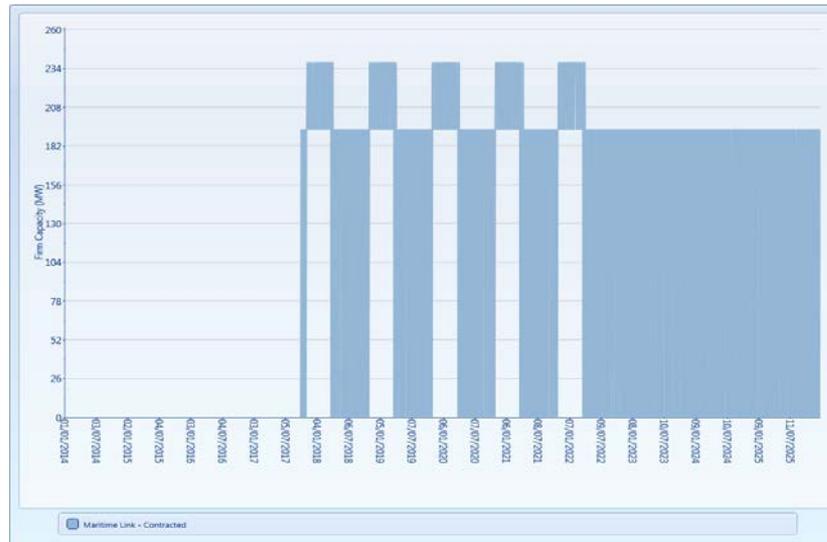
01/04/2015	Burnside 4 comes online
01/01/2016	Minas Basin Pulp and Paper
01/01/2016	Roseway Harmony
01/10/2017	Maritime Link comes online
31/10/2017	Lingan 2 Retires

## Maintenance

Generating fleet maintenance schedule will be the same maintenance schedule used in the IRP simulations.

# System Assumptions – MARITIME LINK

Maritime Link is assumed to be able to provide maximum contracted firm capacity of 153 MW for the Nova Scotia Block, and 198 MW for the Supplemental Block. The Surplus ML energy will be considered as non firm and thus having no capacity for the purpose of this study.



## NB Imports

NB imports will be modeled with no firm capacity for the purpose of LOLE study.

# Appendix 2

## Examples of ELCC Calculation Methodologies and Results in Other Jurisdictions

# ELCC Calculation Methods Used in Different Jurisdictions

Jurisdiction	Methodology Category	Calculation Details	Values
SPP	Peak Period - Percentile	Monthly Capacity Value: 85th Percentile of Wind Generation on Top 10% of Load Hours (up to 10 Years of Data)	
CAISO	Peak Period - Percentile	Monthly Capacity Values: 3-Year Average of Wind Output Equal or Exceeding the 70th percentile, 1pm - 6pm: Apr– Oct / 4pm - 9pm: Jan - Mar and Nov – Dec.	
Bonneville Power Administration	Peak Period – Percentile	Monthly capacity factor during summers 2003 to 2008, only considering 85 <sup>th</sup> and 95 <sup>th</sup> percentile values.	0%
ISO-NE	Peak Period - Median	Summer: 5-Year Average of Median Wind Output, 2pm - 6pm, Jun - Sep Winter: 5-Year Average of Median Wind Output, 5pm - 7pm, Oct – May	Summer Peaking Winter period values high twenties (%).
Ontario IESO	Peak Period - Median	Probability Distribution of Median Wind Output for Modeled (10 Years) and Actual (7 Years) Wind Output Data [Smallest of the 2 Data Points Used each Time]. One Distribution for Summer, One for Winter, Monthly for Shoulder Months. Wind Output for Top 5 Contiguous Daily Peak Demand Hours.	On Summer Peak: 13.6% Winter period (Dec-Feb) values: ~33.4%
NYISO	Peak Period - Average	Summer: Previous Year's Wind Capacity Factor, 2pm - 6pm, Jun - Aug Winter: Previous Year's Wind Capacity Factor, 4pm - 8pm, Dec – Feb	Default Summer: 10%(onshore), 38%(offshore) Default Winter: 30%(onshore), 38%(offshore)
PJM	Peak Period - Average	3-Year Average Wind Capacity Factor, 2pm - 6pm, Jun – Aug	Default: 13% (summer)
BC Hydro	ELCC	Based on synthesized hourly wind data.	24% (onshore & offshore wind)
ERCOT	ELCC	Based on random wind data, not synchronized with load.	8.7% (summer)
Midwest ISO	ELCC	Average ELCC over 7 previous years considered.	14.1% (2014 planning yr), 13.3% (2013 planning yr), 14.7% (2012 planning yr), 12.9% (2011 planning yr)
Quebec Balancing Authority	ELCC	Wind power time series obtained from meteorological data supplemented by analysis of extreme cold weather events.	Winter: 30%

Sources:

NERC. *Methods to Model and Calculate Capacity Contributions of Variable Generation for Resource Adequacy Planning*, March 2011. <http://www.nerc.com/files/ivgtf1-2.pdf>

NREL. *Summary of Time Period-Based and Other Approximation Methods for Determining the Capacity Value of Wind and Solar in the United States September 2010–February 2012*. NREL/SR-5500-54338, March 2012. <http://www.nrel.gov/docs/fy12osti/54338.pdf>

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