

**Maritimes Area
Wind Power Integration Study
Summary Report**

April 2007



Sponsored by:

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Aroostook Wind Energy, LLC (AWE)
Canadian Wind Energy Association (CANWEA)
Evergreen Wind Power, LLC (EWP)
Maritime Electric Company Limited (MECL)
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1. Introduction

The Maritimes Area is a common “Area” designated as such by the Northeast Power Coordinating Council for the purposes of reliability. The Maritimes Area includes New Brunswick, Northern Maine, Nova Scotia, and Prince Edward Island as shown in Figure 1. NBSO is the Reliability Coordinator for this Area.

Figure 1
Maritimes Area



The potential for wind power development in the Maritimes Area is significant. The wind regime is favourable, renewable portfolio standards exist in each jurisdiction within the area, and there is substantial demand for renewable energy in New England. Table 1 shows projections of wind power development in the Maritimes Area in the range of 16-24% of system peak load. Wind production in the order of 20% requires careful consideration in any power system, and even more so in systems such as the Maritimes Area that has significant differences between peak loads and light loads. Some jurisdictions have imposed limits of 10% on development pending further study and experience. It is also important to note that Table 1 shows significant differences in projected wind power versus peak load from one jurisdiction to another within the Maritimes Area.

Table 1**Maritimes Projected Wind Power Development (MW)**

	NB	PE	NS	NM	Area
2004 Peak Load	3333	210	2238	153	5716
2016 Peak Load	-	-	-	-	6288
Wind Capacity	0	43	60	42	145
Projected by 2016	400	200	380	42-542	1022-1522
Penetration in 2016 ¹					16-24 %

While Table 1 shows the projected wind power development, it does not identify the extent to which the wind powered generation is used to serve local load, other loads in the Maritimes Area, or loads outside of the Area. The potential for various combinations of these three types of transactions increases the importance of understanding the impact of wind power on system operations, the associated system costs, and the recovery of such costs.

Given the nature of the industry structure and the regional system operations, the potential exists for new costs to be incurred due to the integration of wind power, but these new costs would not necessarily be borne by the parties that receive the benefits of that wind power. Policies to address these issues need to be established on a timely basis. The uncertainty of a continuation of the policy void that currently exists could stifle investment and prevent realization of the full benefits of the regional wind resources. The choice of treatment of these costs impacts ratepayers, utility shareholders, and generation shareholders throughout the region and thus warrants a regional approach and broad stakeholder consultation.

The current industry structure in the Maritimes Area is presented in Table 2.

Table 2**Industry Structure in Maritimes**

	NB	NM	NS	PEI
Open Access Transmission Tariff	Yes	Yes	Yes	Yes ²
Wholesale Access	Yes	Yes	Yes	Yes
Retail Access - Transmission	Yes	Yes	No	No
Retail Access - Distribution	No	Yes	No	No
Independent System Operator	Yes	Yes ³	No	No
Functional Unbundling	Yes	Yes	Yes	No
Utility Ownership	Public	Private	Private	Private
Renewable Portfolio Standard	Yes	Yes	Yes	Yes

¹ Projected wind power capacity divided by projected 2016 peak load.

² PEI has filed its proposed transmission tariff with the Island Regulatory Appeals Commission.

³ The Northern Maine Independent System Administrator (NMISA) has a stakeholder board.

The Maritimes Area is highly interconnected with both the Quebec and New England transmission systems. Both of these systems have much larger amounts of generation and electrical loads than does the Maritimes Area. Traditionally Quebec, with its predominance of large-scale hydro generation, has been a net exporter of electric power to New England and the Maritimes Area. New England has been a net importer of power from Quebec and the Maritimes Area. New England is projecting substantial load growth, experiencing challenges with building generation within New England, and has had renewable portfolio standards introduced state-by-state. Quebec is pursuing new large-scale hydro projects, and is undertaking substantial development of wind power.

This study is not intended to examine the overall net benefits of wind power generation, but such information provides a useful background to the discussion about wind power integration. Investment decisions regarding specific wind farms will be based on economic evaluations of project developers and load-serving entity procurement processes, both of which can be heavily influenced by government policies (e.g. renewable portfolio standards). Table 3 shows some dated, but indicative, new generation cost information for comparison purposes. The costs in that table include capital costs and the energy costs as of a point in time.

Table 3
Comparison of Levelized Costs⁴

Generation Type	\$0/t	\$15/t	\$30/t
Wind Power ⁵	\$80.00	\$80.00	\$80.00
Natural Gas	\$75.35	\$81.24	\$87.13
Coal	\$59.33	\$72.81	\$86.29
Nuclear (CANDU 6)	\$88.64	\$88.64	\$88.64
Nuclear (ACR-700)	\$73.33	\$73.33	\$73.33

With marginal costs in the northeast set by natural gas and oil-fired generation, the market value of energy alone is volatile and is expected by some to be subject to substantial upward pressure. Although an estimate of the future value of energy would be more relevant to the discussion, it is interesting to note that the unweighted average ISO New England real-time energy price at the boundary of the Maritimes Area and the New England Area for 2006 was \$60/MWh in Canadian dollars.

Clearly, different assumptions can lead to different cost comparison results, but the basic observation can be made that the cost of wind power generation projects are competing against other forms of generation. Characteristics that may also be considered, but which are more difficult to quantify include various types of emissions, visual impacts, effect on tourism, local content, employment, etc. Other key factors to be considered include fuel price risk, price volatility, availability and also reliability of generation.

⁴ Non-wind costs adapted from a Canadian Energy Research Institute report of August 2004.

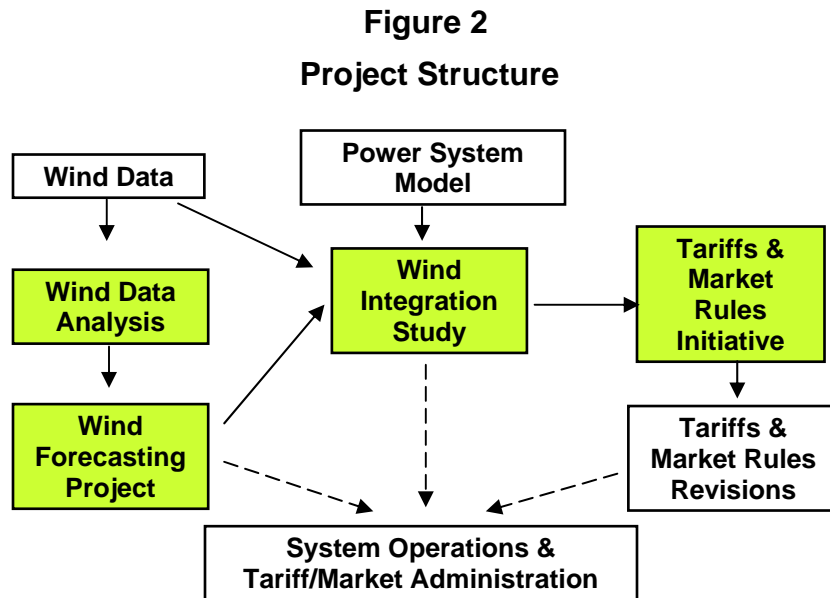
⁵ CANWEA website Frequently Asked Questions.

Potential for high capacity factors, a dependency on carbon-emitting technologies, and provincial and state renewable portfolio standards are resulting in substantial investments in wind power generation in the Maritimes.

The primary focus of this report is wind integration, although there is some focus on the interconnection of wind generation facilities. Wind “interconnection” addresses the physical and electrical requirements of the wind generation equipment and the equipment that connects that equipment to the electric grid in a safe and reliable fashion. Wind “integration” addresses the means by which the characteristics of wind power production are accommodated within the overall portfolio of generation and the load characteristics.

The study explores the characteristics of wind power and the ability of parties to forecast its production, taking into account the wind regimes in some of the sites in the Maritimes that are either already developed, are in development, or are proposed for future development. The costs of integration are explored given the expected characteristics of the wind power and forecasting combined with the characteristics of the existing generation operation and also the region’s consumption and export patterns. Options for reducing the cost of integration are also explored within this study with emphasis on how operational practices could be revised. Lastly, the above-noted observations are to be used to propose modifications to tariffs and market rules within the Maritimes Area so as to provide appropriate treatment of the recently emerged demand for wind power production in the Area.

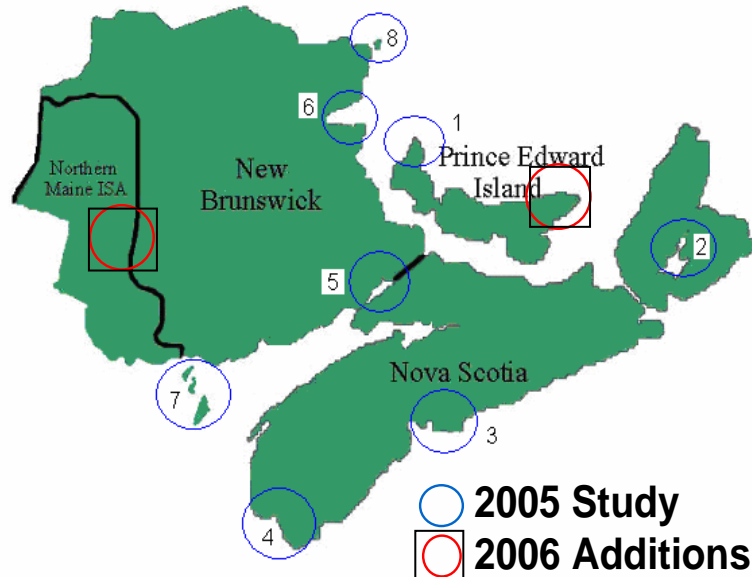
The structure of the project work is captured in Figure 2.



While this report provides a high level overview, four project reports explain how the analysis was performed, assumptions that were made, and provide more detailed results.

This project was undertaken as a Maritimes Area study, but has initially focused on the New Brunswick, Northern Maine, and Prince Edward Island Balancing Area. The approximate location of the sites for which wind data was obtained is shown on Figure 3. Note that the data for the sites marked as 2006 have not been incorporated in all of the analysis as much of the work was completed before that data was made available to NBSO.

Figure 3
Simulated Wind Power Production Data Locations



2. Policies Outside of the Maritimes Area

Various jurisdictions are examining the issue of wind interconnection and wind integration. Some standards are emerging with respect to the interconnection of wind power. The impact of wind integration varies significantly from area to area based on local characteristics such as wind penetration levels, wind power variability, wind power forecasting, as well as the availability of flexible generation, responsive load, and hydro storage. Detailed technical studies specific to local systems have been or are being carried out in many of these jurisdictions.

Published reports are available summarizing the results of such studies. Some of these studies have focussed on identifying the ability of the system to accommodate certain amounts of wind generation. Other studies have focussed on estimating the specific costs of integrating various amounts of wind power. The reports associated with at least some of these latter studies note material costs of integrating wind power. Summaries of costs identified in those studies are readily available from the websites of Natural Resources

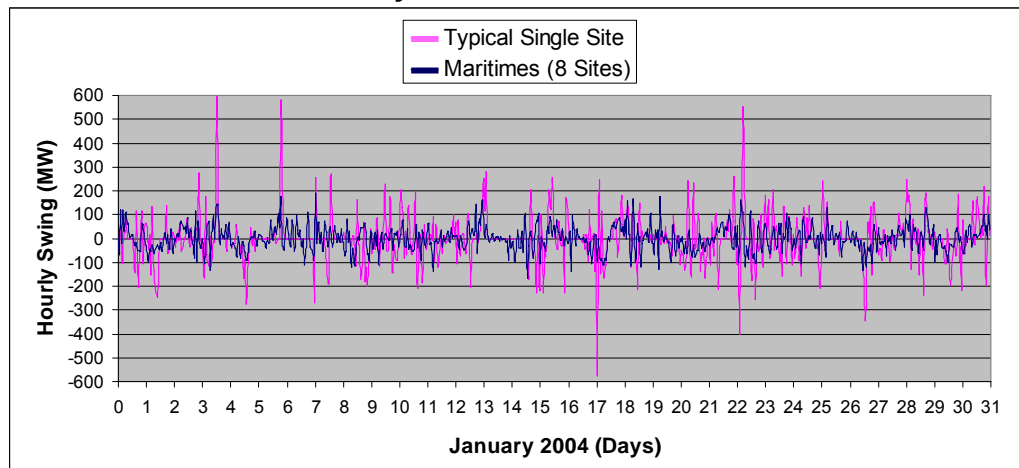
Canada⁶ and the Utility Wind Integration Group⁷. The Natural Resources Canada report indicates that at least a couple of jurisdictions have proposed or implemented specific charges to wind power projects in order to address these costs (e.g. Bonneville Power Authority, and Hydro-Quebec).

3. Highlights of Study Results

Wind Data Analysis

In-depth analysis of the wind data from eight sites around the Maritimes in 2004 confirmed the observation made in the original NBSO Wind Integration Study⁸ that variability of the aggregate hourly wind power production is reduced significantly if production is dispersed throughout the region. Figure 4 illustrates the diversity benefits with respect to the hour to hour swing in production for January 2004.

Figure 4
Diversity Benefits Illustrated



The analysis shows that even with diversity, the variability of wind power production combined with its limited dispatchability is significant relative to that of most other forms of generation in the Maritimes Area. A comparison of the production of a sample wind power plant and that of other facilities in Figure 5 illustrates the greater variability of wind power generation. Also, forecasting the output of a wind power plant is known to be more difficult than forecasting the output of most other forms of generation. These observations provide motivation for further exploration of the characteristics of wind power generation and their consequences.

⁶ Natural Resources Canada's February 2006, *Integration of Wind Generation with Power Systems in Canada*, Table 1.

(http://cetc-varenes.nrcan.gc.ca/en/er_re/inter_red/p_p.html?2006-016)

⁷ Utility Wind Integration Group's *Grid Impacts of Wind Power Variability: Recent Assessments from a Variety of Utilities in the United States*, Table 2. (www.uwig.com)

⁸ The original Maritimes Wind Integration Study of August 2005 is available at www.nbso.ca.

**Figure 5
Power Plant Production**

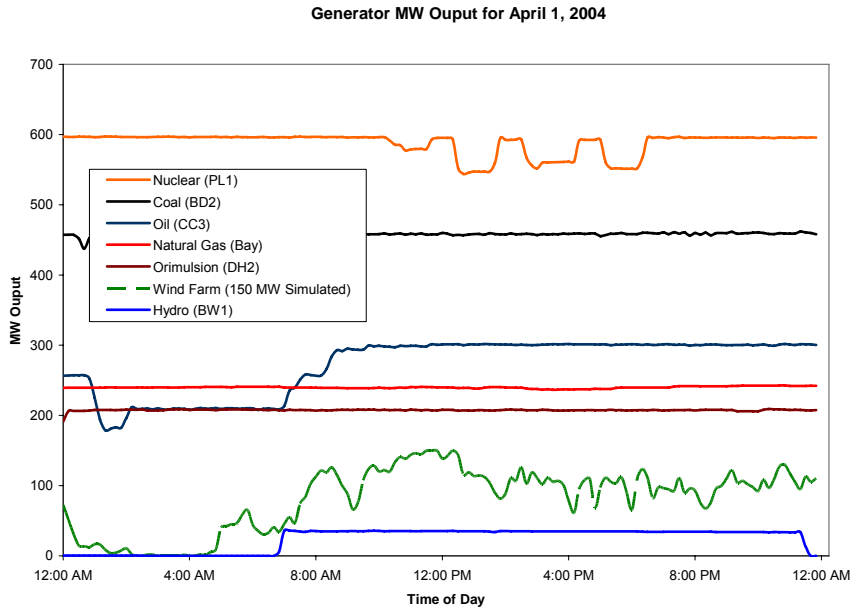
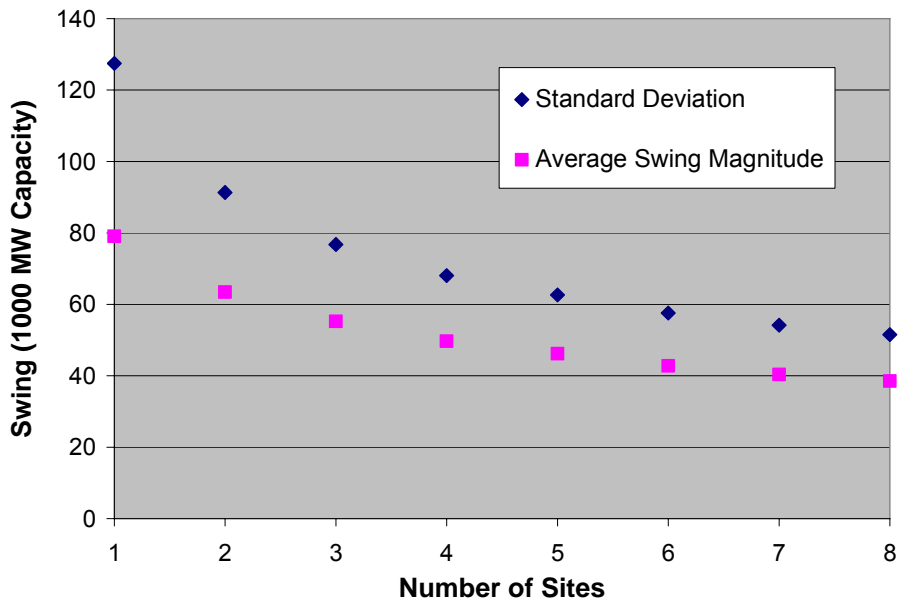


Figure 6 shows the relationship between hourly variability and the number of sites. That graph clearly shows these same diversity benefits for the full 2004 year, but with diminishing returns of spreading the same amount of production across more and more sites.

**Figure 6
Diversity Benefits at Various Levels of Diversity**



The study also looked at wind production variability in comparison to the load variability to provide some perspective on how significant this variability is to system operations. The hour-to-hour variability for 1000 MW of dispersed wind power was found to be less than half of the variability of the Maritimes Area load. Analysis of the data in Table 4 also showed that the standard deviation of the net load is approximately equal to the square root of the sum of the squares of wind power and load standard deviations. This observation supports the hypothesis that there is low correlation between the wind power production and the load.

Table 4
Wind and Load Variability

		Maritimes (1000 MW of Wind)			NB/PEI/NM (600 MW of Wind)			NS (400 MW of Wind)		
		Load	Wind	Net Load	Load	Wind	Net Load	Load	Wind	Net Load
Standard Deviation (MW)		127	51.5	137	83.7	38.5	92.2	60.1	31.1	67.8
% of Hours in Given Range	> 100 MW	19%	3.3%	20%	10%	1.1%	12%	6.9%	0.54%	7.9%
	< -100 MW	20%	3.0%	22%	10%	1.1%	12%	3.9%	0.41%	6.0%
	> 200 MW	6.8%	0.08%	7.9%	3.4%	0.03%	3.6%	0.10%	0.02%	0.44%
	< -200 MW	4.2%	0.07%	5.7%	0.05%	0.00%	0.65%	0.01%	0.00%	0.11%

Wind Power Production Forecasting

Much work was done in the wind forecasting aspect of the project to compile and review work which has been published by other researchers. The knowledge gained from that work was leveraged to simulate wind power forecasting errors for the production sites covered by the study. Actual forecasting error data was made available to the integration study team for one of the eight sites. The characteristics of that data were extrapolated to produce forecasts for the other seven sites. Covariance and correlation between sites were studied and taken into account in the production of those simulated forecasts.

Some of the main points of exploration included answering the following questions:

- What is the best way to measure wind power production forecast performance?
- What is an acceptable threshold for wind power production forecasting?
- What are the diversity benefits of aggregating the forecast errors for a number of sites located throughout the Maritimes Area?

The standard deviation (or root mean squared error) measured over a full month is proposed as an appropriate measure of forecast error. A generic threshold based on the standard deviation as a percentage of the nameplate capacity is proposed to define the safe harbour provision for individual site forecasting. Wind farms providing Day-Ahead forecasts that meet or exceed that threshold will be considered to have performed adequate forecasting. Those not meeting that threshold will be investigated in order to determine whether there are site-specific conditions that make such accuracy in forecasting infeasible, or whether the forecasting efforts are inadequate.

With respect to Hour-Ahead forecasting it is acknowledged that the persistency method is the “target to beat” in the wind power production forecasting industry. That is, the forecast error for a forecasting tool should meet or exceed the error that would have

occurred if the forecast for any given hour had been the actual production that occurred in the previous full clock hour.

The analysis of the covariance and correlation of Day Ahead forecast errors showed that although the forecast errors are not entirely correlated, the correlation is too significant to be ignored. The forecast error correlation coefficients for the simulated data for eight sites are as shown in Table 5.

Table 5
Forecast Error Correlations
Hourly Wind Energy Forecast Error Correlation Coefficients

	Site #1	Site #2	Site #3	Site #4	Site #5	Site #6	Site #7	Site #8
Site #1	1.00							
Site #2	0.07	1.00						
Site #3	0.18	0.20	1.00					
Site #4	0.11	0.17	0.33	1.00				
Site #5	0.16	0.16	0.23	0.20	1.00			
Site #6	0.06	0.25	0.13	0.17	0.30	1.00		
Site #7	0.15	0.18	0.23	0.27	0.25	0.36	1.00	
Site #8	0.22	0.06	0.16	0.12	0.20	0.32	0.20	1.00

Given the aforementioned observations, the proposed thresholds for wind power production forecasting in the NB/NM/PEI Balancing Area are as shown in Table 6. These thresholds are with respect to the standard deviation of the hourly forecast errors measured over a full month expressed as a percentage of the nameplate capacity. In addition to covering Day Ahead and Hour Ahead requirements from individual wind farms, the standard also establishes aggregate Balancing Area forecast error benchmarks in both timeframes. The Balancing Area benchmark is critical for system operations. Balancing is done for the aggregate, not for individual sites, and actual experience over the next few years will provide a better indication as to the appropriate benchmark for aggregate error. Increased forecast diversity benefits experienced in the future may lead to a loosening of the threshold for individual wind farms. Conversely, diversity benefits that are lower than anticipated may result in a tightening of the thresholds for individual wind farms.

Table 6
Initial Wind Power Production Forecasting
Standard Deviation Expectations

	Individual Farms	Aggregate
Day Ahead	25%	20%
Hour Ahead	15%	10%

Accurate wind power forecasting is an important component of wind power integration. NBSO expects advances in the forecasting capabilities which may eventually lead to changes in both the forecasting standard and the metric upon which the performance standard is designed. Changes may also be required as a consequence of further

experience in this region and others. For example, the mean absolute error will be reviewed as a metric that may be more appropriate.

CanWEA believes that if a wind energy forecasting system is adopted to facilitate wind integration, it should be a centralized forecasting system that is paid for by the system operator and makes use of wind data provided to the centralized forecasting system by individual wind energy projects.

Wind Power Production Integration Costs

The analysis indicates that wind power production will lead to material increases in the need for both regulation and load following services. Depending on how the associated costs are treated, cost shifting may occur. Neither actual nor perceived cost shifting between market participants or between jurisdictions is desirable because such a situation is unsustainable in the long run. Uncertainty as to how and when the cost shifting will be addressed can stifle investment.

NBSO has analyzed the potential impacts on costs for the NB/NS/PEI Balancing Area. The unit commitment and dispatch costs are a result of complex modelling of the Balancing Area loads and generation. This analysis is designed to capture the costs that arise from the integration of the wind power into the Balancing Area system, without regard for generation ownership or specific load-serving obligations. This analysis captures costs that arise from both hour-to-hour wind power production variability and day-ahead wind power production forecast error, but does not capture the costs associated with hour-ahead forecast error. Although additional cases were analyzed using the 2004 data, the key results are summarized in Table 7.

Table 7
Estimated Integration Costs
(\$/MWh of Wind Power Production)

Provider	Service	400MW	600MW	800MW
Market	Hour-to-Hour Schedule Balancing	3.41	3.45	5.95
System	Regulation Capacity	0.02	0.02	0.02
Operator	Load Following Capacity	0.03	0.03	0.03
	Regulation Unit Commitment & Dispatch	?	?	?
	Load Following Unit Commitment & Dispatch	0.93	1.21	1.36
	Subtotal	0.98	1.26	1.41
Total		4.39	4.71	7.36

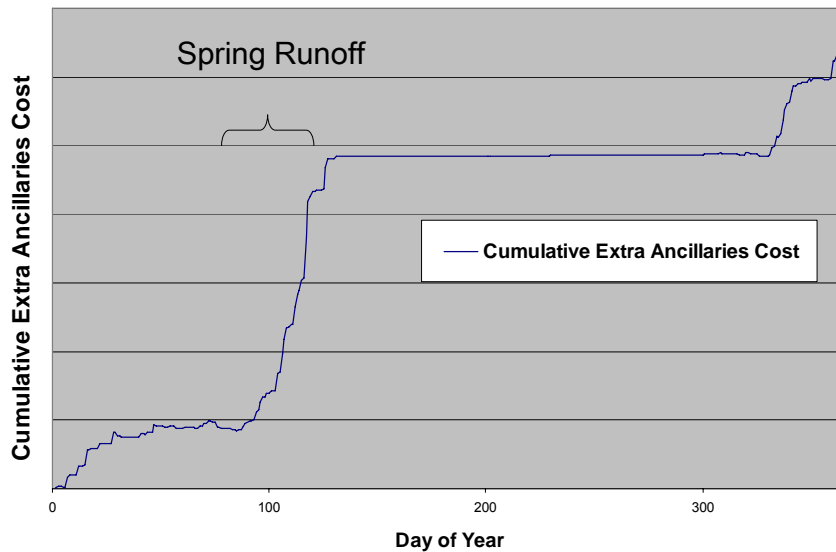
This summary information illustrates that these costs are material, as can be seen in contrast to the current rates for the mandatory standard services for Point-to-Point Transmission services in the Maritimes Area Open Access Transmission Tariffs (OATTs) as shown in Table 8, and relative to the cost of wind power production of roughly \$80.00/MWh (8 cents/kWh).

Table 8
OATT Services
(\$/MWh at 100% Load Factor)

OATT Service	NM ⁹	NB	NS	PEI ¹⁰
Transmission	\$4.26	\$2.88	\$4.91	\$3.61
Scheduling, System Control & Dispatch	\$0.21	\$0.24	\$0.32	\$0.16
Reactive Supply & Voltage Control	\$0.09	\$0.21	\$0.40	\$0.25
Total	\$4.56	\$3.33	\$5.63	\$4.02

The connection between system conditions and the costs for unit commitment and redispatch can be seen in an analysis of the timing of the costs incurred over the course of a year. Figure 7 shows the accumulation of simulated ancillary services costs over the course of the calendar year 2004 for the scenario with 400 MW of wind power at six equally sized sites in the New Brunswick Balancing Area.

Figure 7
Seasonality of Costs
Ancillaries Cost for 400 MW Wind (Six Sites)



The rate of accumulation of costs is rapid during the winter when loads are higher and even more rapid in the spring when the hydro system is fully loaded and thus not available to provide capacity-based ancillary services.

It is important to note that these costs are estimates for the 2004 year and that the estimates required a number of assumptions. Some of the parameters that change from year to year which would have some impact on costs include the duration of the spring runoff, load conditions, availability of generation capacity, level and nature of exports,

⁹ Maine Public Service Rates converted to Canadian funds at \$1US=\$1.18Cdn.

¹⁰ MECL proposed OATT as filed with IRAC on November 30, 2006.

and wind conditions. The two that are thought to have material impact are the duration of the spring runoff and the availability of generation capacity. The year 2004 had a relatively short spring runoff period and so from that perspective the above-noted costs may be conservative. The availability of generation capacity does not normally vary significantly from year to year, but activities such as the Lepreau refurbishment have material impact. Assumed parameters that have some impact on the costs include the location of the wind generation, the amount of generation at each location, unit start-up costs, no-load running costs, and thermal production costs. The assumptions made are based on best estimates and are thought to be reasonable for the purposes of this study.

Treatment of Integration Costs

The materiality of the estimated costs, combined with the potential for cost shifting, leads NBSO to propose that a regulated rate be established so that the costs of providing the incremental regulation and load following services can be recovered from the group of market participants responsible for the generation that is causing those incremental costs. It would then be up to those market participants to recover those costs from their customers along with the other project costs and profit margins. Market Participants would be permitted to schedule the supply of those services from qualifying facilities as an alternative to buying the services from NBSO. This option is already available for load-serving Market Participants in the current tariff.

The alternative supported by at least some wind power proponents is to not charge the market participants that are responsible for the wind power projects, but to socialize that obligation and those costs. The difficulty with socializing the costs is that whatever mechanism is used carries the risk that one portion of society carries a disproportionate share of the costs. Charging the costs directly to the wind power project increases the likelihood that the costs flow to the parties that purchase the output (or at least the attributes) and that get credit for producing the benefits. The point that there are global benefits to renewable energy production is valid, but that does not require having customers in one area pay most or all of the costs of integration.

Another approach has been proposed by a wind power proponent which is a hybrid of the two aforementioned approaches. The socialization approach would be used with respect to wind power development that is to supply New Brunswick load, and the regulated rates approach would apply for other wind power generation. This approach was raised late in the process and requires further analysis. The hybrid approach was proposed to address that fact the services are supplied by New Brunswick resources.

CanWEA's position is that specific costs associated with the integration of wind energy into the system (e.g., ancillary services) should not be charged to wind energy producers. Rather, these charges should be borne by load (the customer base) because wind energy development in the Maritimes is being driven by government mandates and is therefore responding to the public interest. CanWEA notes that the addition of wind energy to the system provides both benefits and costs and therefore market rules and tariffs should not discriminate against wind energy relative to other sources of power.

The actual costs will change over time because they are influenced by the configuration and operation of the system, system costs, the amount of wind power production, and the nature of that production. The actual costs must be tracked and changes to any associated rates would be made as necessary through the appropriate approval processes. Another important observation was the fact that with approximately 400 MW of wind power in the Balancing Area imports were required in some hours and dump energy exports were required in other hours. These occurrences provide a noteworthy threshold with respect to what is required to integrate higher levels of wind power generation.

Capacity Credits

NBSO's initial wind power integration study supported the use of historical capacity factor as the level of capacity credit for wind power production. NBSO uses this approach in its capability period assessments. More specifically, the three year historical winter and summer capacity factors are used respectively for the winter and summer capability period assessments. With respect to the day-ahead and within-the-day resource assessments, the capacity available from intermittent resources such as wind will be based on the most recent production forecast for the respective hour. The ability to operate down to a yet-to-be-defined temperature is under consideration as a requirement to qualify for winter capability period capacity credit.

4. New Brunswick

One of the key observations in the review of the New Brunswick situation was the cost shifting concerns of NB Power Generation Corporation, the current supplier of balancing energy and most of the capacity-based ancillary services required in the NB/NM/PEI Balancing Area. The concern was that as the level of wind power production in the Balancing Area increases, the burden on NB Power Generation may increase their costs without an offsetting increase in revenues. The concern was heightened by the fact that much of the development is anticipated to be for the needs of loads in other jurisdictions such as PEI or New England. A similar concern exists with respect to increases in wind power production in Nova Scotia, because even though Nova Scotia is a separate balancing area, New Brunswick is responsible to manage actual flows between the Maritimes Area and New England, which requires balancing the generation and load of the NB/NM/PEI Balancing Area combined with the net Nova Scotia imbalances which flow through to New Brunswick across the NB/NS interface.

The above-noted cost-shifting issue arose from anticipation of increased capacity costs, increased unit commitment and dispatch costs, lost opportunity costs, and also balancing energy costs. A significant benefit of this review was a better understanding of the various services involved, the approximate costs involved, and the flow of costs for each of these services. At a high level, it is important to make a distinction between the costs that would be between Market Participants as opposed to those that would flow through the system operator. Given the physical bilateral nature of the Maritimes Area marketplace with hourly scheduling obligations, a significant component of the management of wind production volatility rests with the Market Participants. The buyers and sellers are to schedule their hourly transactions to cover the full quantity of forecasted production and consumption. As a consequence, the cost of following the expected

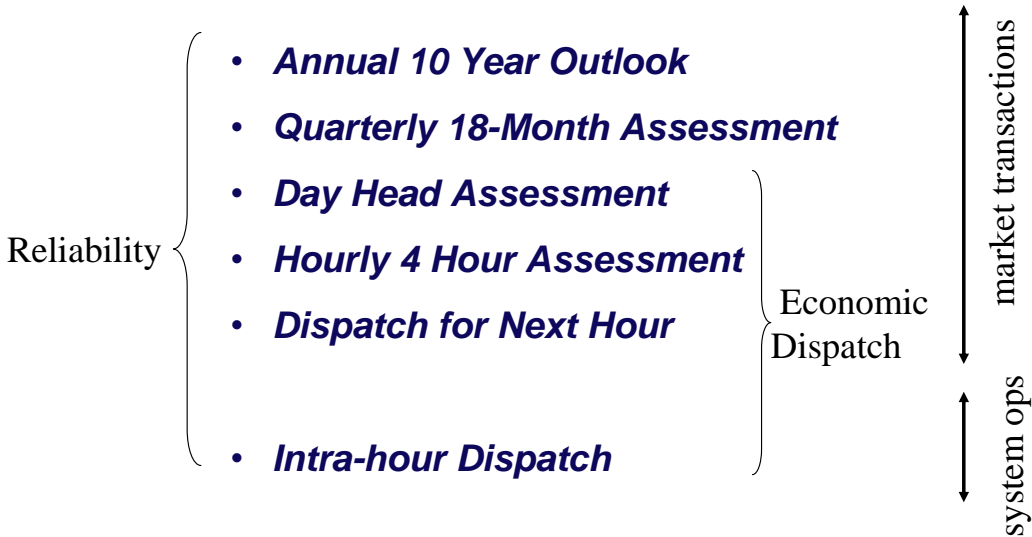
variations in hour-to-hour production is born by the market participants and recovery of such costs is an issue to be dealt with, either explicitly or implicitly, by the contractual arrangements between the buyers and sellers. This study does estimate the costs in the context of wind power generation integrated into the local portfolio of resources. It does not, however, attempt to estimate those costs in the context of exports outside of the Balancing Area and/or the Maritimes Area (e.g. to New England).

The analysis estimates the costs of the intra-hour system balancing that is associated with regulation and load following. These are system operator functions, and thus require the appropriate approvals, and apply to all wind power production (i.e. for deliveries to loads within the Balancing Area and to exports). As shown in Figure 8 and Figure 9 the intra-hour requirements are system operator functions whereas the hour-to-hour requirements are addressed by market transactions. Although the intra-hour requirements are to be dealt with by the system operator, the services required to do so are provided by market participants under contract with the system operator. These services are currently provided by NB Power Generation under contract with NBSO at capacity prices which were established without contemplation of significant amounts of wind power generation connected to the Maritimes Area electric system. NB Power Generation has raised doubts about its obligation and ability to provide these services at the level of the anticipated requirements.

NBSO cannot produce these services itself and has no authority to force generators to provide them in unlimited quantities. Therefore, it may be necessary to set an upper limit on the incremental requirement for Capacity-Based Ancillary Services (e.g. regulation and load following) used to integrate intermittent generation including wind. Even with the exploration of various means to mitigate the impact, such an approach would most likely result in an upper limit on the amount of intermittent generation. Such limits would require that the jurisdictions involved either establish a policy for the allocation of the permitted development, or allow development to continue on a first-come-first-served basis until those limits are reached. Clearly the latter approach could lead to development that is disproportionate to system size, population, and renewable portfolio standard.

Alternatively, increasing the requirement above such limits might be made feasible by the stipulation that such incremental requirements be met by the market participants that are causing the incremental requirement. Such a policy would be similar to the current policy that requires the Point Lepreau nuclear generating station to supply the incremental operating reserves that are attributable to the large size of its contingency relative to the size of the Maritimes Area load. Such an approach provides a compromise that avoids a rigid limit on development, but does not put a limitless responsibility to procure capacity-based ancillary services on the system operator.

Figure 8
Separation of Responsibilities



This distinction between market and system operator responsibilities varies somewhat from market to market, but is generally true for physical bilateral markets such as the organized New Brunswick Market and the regional inter-jurisdictional market.

Figure 9
Balancing Services Provided

Schedule Balancing	Marketers schedule hour-to-hour changes in forecast	} Market
Regulation (AGC)	Capacity Required + Unit Commitment and Dispatch	
Load Following	Capacity Required + Unit Commitment and Dispatch	} System Operator
Operating Reserves	No increase in Capacity Required? Increased activation (balancing energy)	
Balancing Energy	Substantial hourly, but averages zero (unbiased forecast)	

As noted elsewhere in this report, energy imbalances associated with wind power production, combined with the lack of liquidity in the balancing energy market, is a concern for NB Power Generation which is essentially the default supplier of balancing energy to NBSO. Currently the balancing energy market is settled at the marginal bid

prices with no penalties. NBSO is addressing various means to increase the liquidity of the balancing energy market and is requesting active participation in the balancing energy market by other market participants. If additional liquidity is not achieved, pressure to return to punitive imbalance charges will increase, especially with the anticipated variability of wind power production

Interconnection standards for wind power projects have been developed by the Federal Energy Regulatory Commission (FERC) and NBSO proposes to adopt similar standards for New Brunswick. Those standards pertain to low-voltage ride-through capability, voltage support, and SCADA requirements.

Wind Power Pooling is another avenue that was explored, with the main conclusion being that there are potential advantages, but that without a commitment by either wind power producers or load serving entities to participate, there is no justification for building such a model either within New Brunswick or on a regional basis. The potential advantages include reducing the hour-to-hour volatility that must be addressed in bilateral market schedules by individual market participants, increasing the ability to capture renewable energy credits on transactions between Balancing Areas, and reducing exposure of market participants to energy imbalance charges. NBSO has already committed to implementing such a model with respect to hourly imbalances for generation that is scheduled with NBSO, and NBSO seeks input from all parties as to their level of interest in participating in such an arrangement with respect to scheduled and actual production.

The project work has identified a number of areas in which the cost of integration might be reduced. The following are suggested to somewhat mitigate these issues:

- improved production forecasting methods to be developed by both the market participants for wind facilities, and system operators,
- development within each balancing area to be spread around geographically so as to take advantage of the diverse wind speeds,

In addition there are a number of things that should be explored to try and ease the accommodation of the variability and uncertainty such as the following:

- (1) Pursue less onerous deadlines for schedule changes by Market Participants with ISO-New England,
- (2) NBSO pursue use of 15 minute schedules with ISO-New England and Quebec,
- (3) Explore the possibility of dynamic scheduling with ISO-New England and Quebec,
- (4) Demand response capability be developed including bid-based demand response,
- (5) Market rules and connection agreements must provide the right for production from generation facilities, including wind, to be curtailed as necessary to maintain system reliability,
- (6) Market participants in the NB/PEI/NMe Balancing Area selling or buying output from wind facilities should structure contracts so that they can balance schedules hourly (or perhaps even every 15 minutes in the case of transactions with other Areas) to accommodate fluctuations in forecasted production,

- (7) A regional joint RFP for capacity based ancillary services be implemented to encourage use of more resources for the provision of these services,
- (8) Nova Scotia and the NB/PEI/NMe Balancing Area could form a Maritimes Balancing Area so as to take greater advantage of diversity of wind speeds, system peaks, and generation capabilities (one approach that should be considered is to implement a joint dispatch of regulation and load following as a precursor to forming some form of regional market).
- (9) Policies should accommodate storage facilities (pumped hydro, compressed air, etc.).

NBSO has observed that its ability to perform its Balancing Area responsibility can be enhanced by having a better understanding of individual generation production. This is true in day-ahead, hour-ahead, real-time, and also after-the-fact. Such information with respect to intermittent generation is even more important. Such information also makes it easier to manage to the aggregate wind power generation in the area, rather than subsets thereof. NBSO proposes to work with NMISA and MECL to have wind power generation carved out with respect to scheduling, metering, and settlement. Real-time metering of those generators will also be pursued.

The transmission expansion policy was also revisited with respect to the treatment of the situation in which a generator has paid for direct assignment facilities and another generator is developed later and is able to make use of the excess capacity on the line that the first party had paid for. NBSO is considering revising its policy to allow subsequent projects to contribute to the costs as well, and for the parties that connected earlier to receive credit.

5. Northern Maine

As of early 2007, Northern Maine (NMISA-north) has 42 MW of wind generation, with a peak load of approximately 150 MW. This scenario is a prime example of why there is a need to carefully consider the impact of wind integration on the local and regional operations of the power system.

Northern Maine is a part of the NB/PEI/NMe. Balancing Area, and therefore has its intra-hour imbalances addressed by generation which is dispatched by NBSO. Generation in northern Maine is not dispatchable by NBSO for regulation and load following. NMISA is responsible for the administration of the Northern Maine Electricity Market. NMISA acknowledges that a cost-based charge for the increased regulation and load following burden arising from the integration of wind power may be required and understands that the NBSO expects to be applying to the regulator in New Brunswick for approval of such a charge.

The NMISA currently buys regulation and load following services from NBSO under the NB OATT with respect to Northern Maine load's pro rata share of the Balancing Area requirements. NMISA is of the opinion that to the extent that ancillary service obligation and charges are approved by the regulator in New Brunswick as a consequence of costs arising from the introduction of wind power, that such costs should not be passed on

automatically to the load in northern Maine, but rather should be born by the wind generators. Given the potential for extreme differences in the proportion of wind to load in the various jurisdictions within the Balancing Area, and the potential of wind power exports from the Balancing Area, it is fair and reasonable that such obligation and the associated costs be born by the respective generator. The impact of these costs on the sale of the power and/or the renewable energy credits is a matter for the generator and its power contract counterpart to resolve.

6. Nova Scotia

Nova Scotia Power Incorporated (NSPI) and the Nova Scotia Department of Energy elected not to participate in this study. As a consequence, some of the work has been focussed on the Balancing Area comprised of New Brunswick, Nova Scotia, and Northern Maine as opposed to the entire Maritimes Area.

Nova Scotia Power has committed to meet its obligations with respect to balancing supply and demand in Nova Scotia. Doing so will become more difficult and more expensive as the level of wind power penetration increases. To the extent that NSPI is not able to balance supply and demand within its territory, the potential exists for the burden to do so being passed onto the other Balancing Area in the Maritimes and costs being incurred within that area. NBSO intends to continue monitoring the interface between Nova Scotia and New Brunswick accordingly. In addition, NSPI and the Nova Scotia Department of Energy have been made aware of the potential for more efficient balancing of the intermittency of wind power generation by making the Maritimes a single Balancing Area. The tools and methods used in this study could be employed in future analysis of the potential savings of having a single Balancing Area for various levels and locations of wind power.

7. Prince Edward Island

The situation in Prince Edward Island is very similar to that of Northern Maine. As of early 2007, there are 43 MW of wind operating and an additional 30 MW in development on a system with a peak load of just over 200 MW. With the good wind regime, relatively small load, and government encouragement for use of this native resource, it is possible that Prince Edward Island will have a much greater penetration of wind power (i.e. generation relative to the size of its load) than New Brunswick, Northern Maine, or Nova Scotia.

Generally speaking, Prince Edward Island load is served by energy that is delivered to the island from or via New Brunswick. Other than wind power, on-Island generation is used mainly for reserve requirements and supplies energy only during peak load conditions. Therefore, both the inter-hour (hour-to-hour) and the intra-hour (i.e. within the hour) variations in the load, net of on-island wind power generation, are addressed by physical deliveries from off of the Island.

To the extent that they are forecasted, the inter-hour variations are to be taken into account in the hourly scheduled bilateral transactions and therefore are a matter to be addressed

contractually by the load serving entities in Prince Edward Island and their wholesale market energy suppliers as opposed to through Open Access Transmission Tariff services.

On the other hand, since Prince Edward Island is in a common Balancing Area with New Brunswick and Northern Maine, the impact of the intra-hour variations on operations of a generator located in Prince Edward Island is the same as if it were in New Brunswick or Northern Maine. Specifically, the intra-hour variations impact the Balancing Area (New Brunswick, Northern Maine, and Prince Edward Island) requirement for regulation and load following. The regulation and load following services are used by NBSO to balance the system in real-time. These services are supplied by NBSO with services that it purchases from others such as NB Power Generation Company. Given that the impact of intra-hour variations is the same, it is reasonable that the regulation and load following requirements associated with wind generation be treated consistently throughout the Balancing Area.

MECL has filed an Open Access Transmission Tariff with the Island Regulatory and Appeals Commission (IRAC) in Prince Edward Island. MECL has commenced a stakeholder review process and will seek IRAC approval only after completion of that process. The wording in Schedule 3 of the proposed MECL OATT filed on November 30, 2006 already contemplates that the service may be provided by the Control Area¹¹ operator and that to the extent that this occurs, such costs will be passed on to the Transmission Customer.

The Transmission Customer must either purchase this service from the Transmission Provider or make alternative comparable arrangements to satisfy its Regulation and Frequency Response Service obligation. To the extent the Control Area operator performs this service for the Transmission Provider, charges to the Transmission Customer are to reflect only a pass-through of the costs charged to the Transmission Provider by that Control Area operator.¹²

As part of the stakeholder review process, MECL is now proposing to add more specific wording to the OATT relative to this issue. This wording would indicate that to the extent that there are Control Area Operator charges for capacity-based ancillary services such as regulation and load following associated with wind power, these charges will be passed on to the wind farms. MECL also commits to working with NBSO and the other parties involved in this study to find ways to ease the integration of wind power into the Balancing Area.

¹¹ The term Control Area exists in many OATTs, but this term is being phased out by NERC and NPCC and replaced by the term Balancing Area.

¹² MECL Proposed OATT (as filed with IRAC on November 30, 2006), Schedule 3.

8. Comparisons

Table 9 and Table 10 contain comparisons of observations and proposals for the various jurisdictions. Table 11 illustrates a similar comparison for interconnection requirements. Note that the discussion with Prince Edward Island and Northern Maine system operators is in its infancy and these proposals can be expected to evolve.

Table 9
Defined Ancillary Service Charges for Loads

	NB	NMe	NS	PEI ¹³
Regulation	√	√	√	√
Load Following	√	√	√	√
10 Minute Spinning Reserves	√	√	√	√
10 Minute Supplemental Reserves	√	√	√	√
30 Minute Supplemental Reserves	√	√	√	√
Energy Imbalance	√	√	√	√

To date, the proposal is that a mechanism be implemented to recover the incremental costs associated with regulation and load following arising from wind power production. System operators in Northern Maine and Prince Edward Island are in agreement that to the extent NBSO assesses such charges that they should be passed on to the wind power producers.

While increased regulation and load following capacity requirements are expected, increased reserve capacities may not be required. However the frequency of activation of reserves will increase. For example, the 2004 data indicated that for 250MW at each of 4 sites in New Brunswick, the maximum drop in hour to hour production would have been only slightly less than 400 MW. While significant, this drop in production is less than the first and second contingencies and thus would not trigger an increase in required reserves.^{14 15} Nonetheless, as an example, hour-to-hour drops of at least 200 MW would have occurred in almost 82 hours, and such drops in production may require activation of reserves. Swings that are in excess of 200 MW (and even less) may require activation of reserves, but that depends largely on whether or not they were forecasted one-half hour before the hour and scheduled accordingly. Another area of concern is the requirement for NBSO to report any contingency events in excess of 300 MW and such events have cost implications.

Whether or not reserve requirements are increased by the integration of wind power depends on the amount of wind generation, diversity of the wind production, and the quality of the hour ahead forecasting. Therefore, this issue will need to be revisited on occasion as conditions change and as more experience is gained.

¹³ Pending IRAC approval.

¹⁴ The 1st (i.e. largest) and 2nd contingencies today are Lepreau at 600 MW (approximately 700 MW after refurbishment) and Belledune at 466 MW.

¹⁵ The 10 minute reserve requirement is 100% of the largest contingency and the 30 minute reserve requirement is 50% of the second largest contingency.

Table 10
Proposed Charges for Wind Generation

	NB	NMe	NS	PEI ¹⁶
Regulation	√	√	?	√
Load Following	√	√	?	√
10 Minute Spinning Reserves	x	x	?	x
10 Minute Supplemental Reserves	x	x	?	x
30 Minute Supplemental Reserves	x	x	?	x

Since the focus of the project is wind integration the coordination of interconnection standards is in its infancy. Nonetheless, Table 11 shows the current status and identifies where more work is required. The voltage support, low-voltage ride-through and SCADA items are addressed by the Federal Energy Regulatory Commission (FERC) standards. NBSO proposes to add the requirement for telemetry of the turbine status, current temperature, wind speed, and wind direction at the wind farm to the SCADA system used by NBSO.

Table 11
Interconnection Standards

	NB	NMe	NS	PEI ¹⁷
Voltage Support	√	?	?	?
Low-Voltage Ride-Through	√	?	?	?
SCADA	√	?	?	?
Curtailment	√	?	?	?

With respect to curtailments, it is proposed that generation connection agreements clearly specify the right of the system operator to curtail wind power generation in accordance with the relevant tariff or market rule provisions. NBSO has the same rights with respect to other forms of generation and with respect to loads. The NB Market Rules allow for curtailments for reliability reasons and to the extent feasible such curtailments are to be done based on the most economical approach, given the dispatch data provided by the Market Participants for the respective generators. The generator must be able to respond in accordance with such dispatch instructions for partial or full production curtailments.

CanWEA has noted that wind integration would be more easily facilitated through a regional market and network (as opposed to province by province) run by a regional system operator with common market rules and tariffs throughout the region.

¹⁶ Pending IRAC approval.

¹⁷ Pending IRAC approval.

9. Summary

Analysis of work done in other jurisdictions, simulated production and simulated forecasts, and examination of system costs have allowed NBSO to increase its knowledge of issues associated with wind power production and propose enhanced treatment of wind power production. The work has also led to identification of areas in which the cost of integration may be reduced through new practices by system operators and market participants. Regional cooperation has made these efforts easier and ongoing cooperation of various stakeholders can help the realization of the potential benefits of wind power production in the region, while minimizing costs.

10. Detailed Reports

The detailed work performed during the course of the project has been captured in individual reports on the topics listed below.

1. Wind Power Production Analysis
2. Wind Power Production Forecasting
3. Wind Power Integration
4. Tariff and Market Rules