Potential Cost Impacts of A Renewable Portfolio Standard in New Brunswick

Prepared by:
Tim Woolf, David White,
Cliff Chen, and Anna Sommer
Synapse Energy Economics
22 Pearl Street, Cambridge, MA 02139
617-661-3248
www.synapse-energy.com

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List of Acronyms

BDt	Bone-dried tones
CanWEA	Canadian Wind Energy Association
CEA	Canadian Electricity Association
CF	Capacity Factor
CFS	Canadian Forest Service
ENS	Environment News Service
Helimax	Helimax Energy, Inc.
ICF	ICF Consulting
INEEL	Idaho National Engineering and Environmental Laboratory
Innergex	Innergex Group
Irving	Irving Pulp and Paper
kW-yr	Kilowatt-year
kWh	Kilowatt-hour
LFG	Landfill Gas
MW	Megawatt
NBP	New Brunswick Power Company
NE	New England
Nexus	Energy Nexus Group
Nova Scotia DOE	Nova Scotia Department of Energy
NS	Nova Scotia
NYDPS	New York State Department of Public Service
O&M	Operations and Maintenance
OEI	Optimal Energy Investment
PEI	Prince Edward Island
QC	Quebec
Quebec MNR	Quebec Ministry of Natural Resources
REC	Renewable Energy Certificates
RFP	Request For Proposals
REPiS	Renewable Electric Plant Information System
RPS	Renewable Portfolio Standard
WIP	Waste In Place
WPPI	Wind Power Production Incentive

1. Executive Summary

The purpose of this study is to provide estimates of the potential cost impacts of RPS regulations in New Brunswick. We rely upon industry data and conversations with renewable developers to estimate the likely amount and cost of renewable generation available in New Brunswick and the neighboring regions for 2006 through 2015. We compare those costs with an estimate of the future avoided cost of electricity in New Brunswick, to determine a "renewable energy premium." This renewable energy premium is then multiplied by the amount of renewable generation required by the RPS in any one year to determine the total cost of the RPS requirements, and the potential increase in retail electricity prices.

We analyze two different RPS target levels. First, we investigate a scenario where the target is one percent in 2006, and increases by one percent per year, until it reaches ten percent by 2015. Second, we investigate a scenario where the target is 0.5 percent in 2006, and increases by 0.5 percent per year, until it reaches five percent by 2015.

We also look at the role of renewable generation that is imported into New Brunswick for the purposes of the RPS. For the One Percent RPS case, we analyze two import scenarios: where imports are limited to 20% of the total RPS generation, and where imports are not allowed to be used as part of the RPS generation.

We find that in most cases the cost impact of the RPS is likely to be quite small. Table ES-1 presents the cost impacts of the scenario where the RPS target equals one-percent and the imports are limited to 20%.

Table ES-1 Cost Impacts: 1% RPS, 20% Import Limit

Year	In-Province Renewable Energy (GWh)	Avg Renew Premium ($/MWh)	Avg Renewable Premium Cost (M$)	Average Price Impact (%)
2006	159	20.5	3.2	0.3%
2007	320	18.3	5.9	0.5%
2008	484	7.6	3.7	0.3%
2009	643	12.2	7.8	0.6%
2010	819	26.4	21.6	1.7%
2011	997	15.9	15.8	1.2%
2012	1,186	13.8	16.4	1.2%
2013	1,381	15.8	21.8	1.5%
2014	1,582	16.1	25.4	1.7%
2015	1,781	17.1	30.5	2.0%
2016	1,798	9.7	17.4	1.1%
2017	1,816	9.4	17.0	1.1%
2018	1,835	1.3	2.4	0.2%
2019	1,853	0.9	1.7	0.1%
2020	1,872	-6.5	-12.2	-0.7%
2021	1,890	-7.3	-13.8	-0.8%

As indicated in the table, the RPS premium is expected to be between $8/MWh and $26/MWh over the next ten years. The average price impact is expected to be less than one percent in the first five years, increasing up to two percent after ten years. After 2015 the renewable premium and the price impact drops significantly, primarily because the avoided costs increase significantly, and also because the RPS target stops increasing. [1]

In the case where the RPS is set at one-half percent per year, the renewable premiums range between $5/MWh and $22/MWh, and the impacts on retail electric costs are less than one percent per year in all years.

In the case where no imports are allowed to supply the RPS, the renewable premiums remain high at roughly $16/MWh to $35/MWh in the first ten years. The average price impact reaches roughly two percent by 2010 and nearly three percent by 2015.

In this case where no imports are allowed to supply the RPS, we find that there may not be sufficient renewable resources within New Brunswick to satisfy the ten percent RPS target in that year. Under the renewable supply assumptions we use in this analysis, there would be a shortfall of 198 GWh in 2015, which is roughly 11% of the total target in that year. In practice, the renewable industry in New Brunswick may be able to develop enough generation by this time to meet the RPS target in this case where imports are excluded.

While New Brunswick has a large potential for wind generation, especially along its coast lines, the amount of wind generation that can be utilized for the RPS may be limited due to grid stability issues.[2] These grid stability issues may determine the extent to which New Brunswick renewables can be developed, and thus should be considered in setting the RPS target and the import limits. The grid stability issues are especially important in New Brunswick where there is a significant amount of wind generation potential but limited potential for other types of renewable generation.

[1] Note that since this economic analysis was performed, the prices of oil, natural gas and coal have increased significantly, and may remain at higher levels for the near- to mid-term future. If this analysis were updated to account for the new fossil-fuel prices, the renewable premiums and the average price impacts would be significantly smaller than those presented in this study.

[2] Some of these grid stability issues are discussed in Appendix A.

2. Methodology for Estimating RPS Cost Impacts

Sources of Data

We began our analysis with a review of the existing literature regarding the costs and availability of renewable resources in New Brunswick and the neighboring regions. We supplemented this literature with relevant information regarding renewable resource costs and performance in the United States, where appropriate.

Most of our inputs and assumptions, however, are based on information obtained from key market players in New Brunswick and neighboring regions. New Brunswick Power Company (NBP) was especially helpful in this regard, as were several developers of renewable technologies in the region. Additional information on the data sources we used is provided in citations below and the Reference section.

Forecast of Avoided Costs

We estimate the cost impacts of the New Brunswick RPS by determining a "renewable energy premium." This premium (in $/MWh) represents the extent to which the cost of the renewable energy used to comply with the RPS exceeds the cost of energy that would have been generated in the absence of the RPS (i.e., the avoided costs).

We worked with New Brunswick Power to develop avoided cost estimates. The analyses and results are described in more detail in Section 3 below.

NBP used its resource planning model to estimate the costs of operating its system under several scenarios. The Base Case scenario indicates the cost of operating the system in the absence of the RPS. The One Percent RPS scenario indicates the cost of operating the system with the RPS equal to one percent per year up to ten percent by 2015. Similarly the One-Half Percent scenario indicates the costs of operating the system under this less stringent RPS target. The costs of the Base Case scenario are compared with the costs of the RPS scenarios to indicate the avoided costs associated with each of the RPS scenarios.

New Brunswick Power As the Primary Developer of Renewables

New Brunswick has recently solicited and purchased significant amounts of wind generation, through competitive bidding auctions. We assume that this is the most likely model under which renewable resources will be developed under the RPS.

Accordingly, we do not need to make any assumptions regarding a market for renewable energy credits (RECs), or the extent to which that market might influence the cost of complying with the RPS. Instead, we simply assume that the cost of complying with the RPS will be based on the average costs of developing renewable projects under competitive bidding practices.

Definition and Location of Eligible Resources

At this time, we expect that the following renewable resource types will be eligible for the New Brunswick RPS: wind, solar, biomass, hydro, ocean thermal and tidal/wave energy. In each case, the renewable power project must be certified by Environment Canada's Environmental Choice Program in order to qualify for the New Brunswick RPS. Additional information about the contents and design of the proposed New Brunswick RPS regulations is provided in Section 4 below.

All qualifying renewable resources located within New Brunswick will be eligible for the RPS. With regard to imported power, we made several assumptions :

- First, the neighboring region must have a system in place to accurately account for the renewable attributes of the power generated there. This system must be sophisticated enough to prevent double-counting of renewable attributes.
- Second, there must be a transmission interconnection between New Brunswick and the neighboring region sufficient to allow the renewable energy to flow into New Brunswick.
- Third, the renewable project developers in the neighboring regions must demonstrate that the renewable energy used to comply with the New Brunswick RPS was sold into New Brunswick.
- Fourth, there will be a limit on the percentage of the RPS that can be fulfilled by imports from the neighboring regions in any one year. In this study we evaluate the cost impacts of two import limits. In the Base Case, imports are allowed to make up no more than 20% of the total renewable energy in the RPS in any one compliance year. In the No Imports scenario, none of the imports are allowed to be used to comply with the RPS.

Comparison of Renewable Supply and Demand

The New Brunswick RPS will establish a schedule of renewable energy targets that must be met in each year. The targets being considered are described in Section 4 below. These RPS targets create a demand for renewable energy, beginning in 2006. We investigate the potential costs associated with two different RPS targets, in order to see how the costs are likely to change with the targets.

One of the primary tasks of our analysis is to identify the types and cost of renewable generators that are most likely to meet these RPS demand targets. We do this by constructing a set of "renewable supply curves," which includes the costs and amounts of all eligible renewable energy sources that are available to meet the New Brunswick RPS. The renewable supply curves rank the energy sources in order of cost (in $/MWh), with the lowest cost resources coming first. The assumptions we used to construct the renewable supply curves are described in Section 5 below. We then compare the RPS demand curve with the renewable supply curve in order to identify the type and amount of each renewable resource that is likely to meet the RPS in any given year. The results of this analysis are provided in Section 6 below.

Renewable energy availability, cost and performance characteristics are likely to change over time. We have developed several renewable energy supply curves for different "snapshot" years, including: 2006, 2009, 2012, and 2015. We compare these renewable supply curves to the RPS demand in each of these snapshot years in order to determine the mix of renewable resources that will be used to comply with the RPS in each of these years. We then interpolate between these snapshot years in order to estimate the renewable energy premium for the intervening years.

Impact on Electricity Prices

Finally, we use the renewable energy premiums to estimate the impact of the New Brunswick RPS costs on total electricity costs and customer bills. The renewable premium (in $/MWh) is multiplied by the amount of renewable energy required to meet the RPS target in each year (in MWh) to provide the total RPS cost. The total RPS costs are then compared to future electricity costs and average prices. The results of this comparison are presented in Section 7 below.

3. Avoided Costs of Electricity

As noted above, the renewable premium for the New Brunswick RPS in any one year will be equal to the difference between the total cost of the renewable energy and the avoided cost of electricity in New Brunswick. Thus, the avoided cost of electricity will have a significant effect on cost impacts of the New Brunswick RPS.

The avoided costs for this study were developed by New Brunswick Power, using their PROSCREEN resource planning model. This model is used to estimate the capital, fuel and operating costs of the NBP system under the different scenarios. The difference between the Base Case scenario and the RPS scenarios indicates the avoided costs of each scenario.

NBP used its most recent planning assumptions regarding customer demand, fuel prices, power plant availabilities, power plant operating characteristics, transmission constraints, and other system operating parameters. The Company assumed that the Pt Lepreau power plant would be out of service for refurbishment during 2008 and 2009, but would be back on-line by 2010.

The results of New Brunswick Power's analysis are presented in Table 3.1 below, for the One Percent RPS scenario. It includes avoided energy costs, avoided capacity costs, and the avoided costs associated with the purchase of greenhouse gas (GHG) permits. It presents these costs both in terms of millions of dollars (for the One Percent RPS case), and in terms of $/MWh.

The primary component of avoided costs is the avoided energy costs, i.e., the avoided fuel and O&M costs associated with running New Brunswick Power's existing power plants. The majority of the avoided energy comes from the Coleson Cove oil-fired power plant (roughly 75% on average throughout a year), and most of the remainder of the avoided energy comes from the Belledune coal-fired power plant (roughly 15% on average throughout a year). Thus the costs of operating these two plants are the biggest factor determining the avoided energy costs.

Avoided energy costs will vary throughout a year, depending upon the mix of power plants available and the customer demand for energy at any one point in time. On the New Brunswick Power system, the avoided energy costs are lower in the summer months when customer demand is lower. During these months, the avoided energy includes less power from Coleson Cove and more from Belledune.

Note the avoided energy costs increase dramatically in 2008 and 2009, and then drop down again in 2010. This pattern is due to the Point Lepreau refurbishment during 2008 and 2009. When Point Lepreau is out of service, more expensive plants are operating on the margin, and these more expensive plants are avoided in the RPS case.

NB Power assumes that their avoided capacity costs will be zero until new generation capacity is needed on the system in 2016. This assumption is based on a loads and resources forecast indicating that the Company will have excess supply until 2016. At that time, the avoided capacity costs will be based on the capacity costs of new natural gas-fired combustion turbines, for which the capital costs are assumed to be roughly $600/kW.

Table 3.1 Avoided Costs in New Brunswick: 1% RPS Case

Year	Avoided Energy ($mil)	Avoided Capacity ($mil)	GHG Permits ($mil)	Avoided Energy ($/MWh)	Avoided Capacity ($/MWh)	GHG Permits ($/MWh)	Total Avoided Costs ($/MWh)
2006	7.6	0.0	0.0	47.8	0.0	0.0	47.8
2007	15.1	0.0	0.0	47.3	0.0	0.0	47.3
2008	27.4	0.0	0.4	56.9	0.0	0.8	57.7
2009	33.9	0.0	0.6	52.8	0.0	1.0	53.8
2010	32.7	0.0	1.3	39.6	0.0	1.6	41.2
2011	51.7	0.0	1.7	51.5	0.0	1.7	53.2
2012	62.5	0.0	4.7	52.7	0.0	4.0	56.6
2013	73.8	0.0	5.5	53.3	0.0	4.0	57.3
2014	87.7	0.0	6.3	55.4	0.0	4.0	59.4
2015	101.5	0.0	7.1	56.7	0.0	4.0	60.7
2016	108.9	8.7	7.2	60.8	4.8	4.0	69.7
2017	112.4	8.7	7.2	62.7	4.8	4.0	71.6
2018	120.6	17.7	7.2	67.4	9.9	4.0	81.2
2019	124.3	17.7	7.3	69.4	9.9	4.1	83.3
2020	131.1	27.1	7.3	73.2	15.1	4.1	92.4
2021	135.8	27.1	7.2	75.8	15.1	4.0	94.9

The avoided costs associated with purchasing GHG permits is based on the federal government's current proposal for addressing climate change in the electricity industry. New Brunswick Power estimated the total amount of GHG permits that it would need to purchase to support the operation of its fossil-fired units in both the Base Case and the RPS scenarios, accounting for the different level of gratis permits allowed in each scenario.

In the RPS scenarios, the Company will be required to purchase less GHG permits, as a result of reduced generation from its fossil-fired power plants. Based on input from the Department of Energy, we assume that GHG permits will cost $15/tonne in 2008 through 2011, will increase to $30/tonne in 2012, and will increase at the rate of inflation (2%) after that. Under these assumptions the avoided costs associated with purchasing GHG permits by 2015will be roughly $7 million per year, which is equivalent to roughly $4/MWh.

As a final note, the avoided energy costs were estimated by New Brunswick Power in the late spring and early summer of 2005. Since then, oil, gas and coal fuel prices have increased significantly, and many analysts expect that the prices will remain high for at least the near-term future. As such, the avoided energy costs above are likely to significantly understate the actual avoided costs on the system, and thus our analysis is likely to overstate the cost impacts of the RPS cases.

4. The New Brunswick RPS Design

Section 149(1)(k) of the New Brunswick Electricity Act requires the establishment of a renewable portfolio standard. In addition, the multi-stakeholder Market Design Committee (MDC) established several key principles for designing a renewable portfolio standard , including:

- The RPS target should be based on a percentage of total retail customer electricity use.
- The RPS requirement should be placed on retail loads, rather than on generators.
- The RPS regulations should require that the three municipal distribution utilities and large industrial customers who choose a competitive supplier or self-supply to demonstrate that they meet the RPS obligation.
- The RPS regulations should require the standard service, default supplier to meet the RPS obligation on behalf of non-contestable customers.
- The RPS target should increase gradually over time at a predetermined rate.
- In order to be eligible for RPS compliance, a renewable project must either (a) be new, (b) be incremental capability from an existing renewable facility, or (c) be a refurbishment of an existing renewable facility in lieu of retirement.

Several aspects of the final RPS design will affect the cost impacts of the RPS, and thus our estimate of the cost. Here we list those aspects of the RPS design that we have assumed as part of our economic analysis:

- The RPS target will begin in the year 2006, will increase steadily for ten years, and will remain constant after that.
- The RPS will apply to all retail sales within New Brunswick, including the sales to the municipal distribution companies.
- Only new renewable projects will be eligible for compliance with the RPS, where new renewable projects are those installed after December 31, 2003.
- The following types of renewable generators will be eligible for the compliance with the RPS: solar, wind, ocean thermal, wave or tidal energy, landfill methane gas, anaerobic digester gas, an “eligible biomass fuel” or the energy in flowing water. The renewable generator must also be certified as “low-impact, renewable electricity” by Environment Canada’s Environmental Choice Program. In order to qualify under this program, biomass fuels must meet several environmental standards, including emissions limits.
- Renewable energy in neighboring regions can be used for RPS compliance as long as (a) the neighboring region has a compatible system for accounting for renewable attributes; (b) the renewable energy can be transmitted into New Brunswick; (c) the renewable developer can demonstrate that its power is sold into New Brunswick;

and (d) the total amount of renewable imports in any one year does not exceed a certain percentage of the RPS target.

- For at least the near- to mid-term future, New Brunswick Power will be the primary, and possibly the only, entity responsible for complying with the RPS, and will purchase renewable generation through efficient procurement procedures, such as competitive bidding practices.

The Restructuring Act does not specify what the RPS target should be. One of the objectives of this study is to investigate the potential cost impacts of different RPS targets, in order to help identify an appropriate RPS target for the regulations. Thus, we have chosen two different target levels to study:

- A One Percent RPS, where the target is one percent in 2006, and increases by one percent per year, until it reaches ten percent by 2015. After 2015, the RPS target is held constant at ten percent.

- A One-Half Percent RPS, where the target is 0.5 percent in 2006, and increases by 0.5 percent per year, until it reaches five percent by 2015. After 2015, the RPS target is held constant at twenty percent.

Table 4.1 presents New Brunswick Power's most recent load forecast through 2015, as well as the amount of energy that will be needed to meet the three RPS targets analyzed in this study.

Table 4.1 Renewable Energy Required By Two NB RPS Targets (GWh)

	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
NBP Demand	15,864	16,020	16,133	16,067	16,377	16,617	16,943	17,263	17,583	17,805
Half Percent	79	160	242	321	409	499	593	691	791	890
One Percent	159	320	484	643	819	997	1,186	1,381	1,582	1,781

Source: The New Brunswick Power electricity demand forecast was provided by NBP.

5. The Cost and Availability of Renewables in the New Brunswick Region

5.1 Methodology

The cost and availability assumptions informing our renewable supply analysis were generally derived from one or more of the following sources:

- Conversations with renewable developers, utility personnel, and other experts
- Government reports and statistics
- RPS cost studies for states in New England
- Our best professional judgment

All of the cost and operating assumptions discussed in this section involve some amount of uncertainty and unpredictability. We have accounted for this by assuming three levels of costs and availabilities for each of the resource types. For each renewable resource type discussed above we assume a low, medium and high level of cost and availability. This methodology and our assumptions regarding the three levels largely are based on the Vermont and Massachusetts RPS studies. (Grace et. al. 2002, Synapse 2003).

This approach provides a more detailed supply curve, and allows for greater opportunities for a low-cost version of one type of renewable to displace a high-cost version of another type. The results provided in Section 6 present an aggregated result for all of the three levels for each resource type.

5.2 Levelized Costs of Renewable Generation

In order to compare the total costs of the renewable options on an equivalent basis, we estimated the levelized cost (in $/MWh) of each resource. This levelized cost includes all costs associated with financing, construction and operation of a renewable generator over its lifetime. The levelized cost represents the constant stream of costs over the life of the plant, which when discounted back to present value dollars is equal to the present value of the actual stream of costs.

We used New Brunswick Power's financial model for estimating levelized costs of generation resources, along with NB Power's assumptions regarding the cost of financing renewable facilities. The Company assumes that projects will be financed with 60% debt and 40% equity, and that debt will cost 8% and equity will cost 12%. These financial assumptions are based on the presumption that NB Power will be responsible for purchasing renewable generation through long-term contracts with renewable developers.

NB Power also assumes that most renewable generators will have a book life of 20 years and a tax life of 20 years. Hydro projects are the exception to this rule; they are assumed to have a book life of 30 years and a tax life of 30 years.

New Brunswick Power's financial model uses these assumptions, plus the inputs for power plant construction costs, capacity factors, O&M costs, and fuel costs to calculate the revenue requirements per year that would be necessary for the Company to recover all costs plus their allowed return on equity. These annual revenue requirements are then levelized to develop a single number that reflects lifecycle costs in $/MWh.

The results for each renewable resource are presented in the tables below. The levelized costs are calculated and presented in nominal terms (as opposed to real terms), so that the electricity cost impacts resulting from these levelized costs will also be in nominal terms.

5.3 WPPI, RPPI and GHG Offset Credits

We have accounted for government policies that will affect the economics of renewable development in New Brunswick. We have used input assumptions from the Department of Energy to account for three such policies.

First, we assume that the Wind Power Production Incentive (WPPI) will be expanded beyond the 1000 MW national limit, which would allow all eligible projects to benefit from the incentive. The WPPI provides an incentive of $10 per MWh for ten years for wind projects commissioned prior to April 2006. We assume that the WPPI will be extended beyond this date, and will be in place at least through 2015.

Second, we assume that the Renewable Power Production Incentive (RPPI) will be implemented by 2006, and will be in place at least through 2015. The RPPI is identical to the WPPI, except that it applies to all renewable projects developed in Canada.

Third, we assume that renewable projects in Canada will be eligible to receive GHG offset credits, according to the federal government's current proposal for addressing climate change in the electricity industry. As noted above, we assume that GHG permits will cost $15/tonne in 2008 through 2011, will increase to $30/tonne in 2012, and will increase at the rate of inflation (2%) after that. The GHG offset credits are assumed to be based on an emissions rate of 240 tonnes/GWh. According to these assumptions, the GHG offset value will equal zero in 2006, $3.6/MWh in 2009, $7.2/MWh in 2012, and $7.4/MWh in 2015.

The economic impacts of the WPPI, the RPPI and the GHG offset credits are included in the levelized costs presented in the tables below for each renewable resource located in Canada.

5.4 Imports

New Brunswick has existing intertie capacity with Quebec, Nova Scotia, Prince Edward Island, and New England. The current transmission network can support 1,200 MW of import capacity from Quebec and 400 MW from Nova Scotia during the winter.[3] It is

[3] New Brunswick Market Design Committee: Congestion Management Issues, prepared by Navigant Consulting, 9/27/2001.

possible that the transmission capacity between New Brunswick and New England will be expanded to allow imports from New England, though at this time the electricity flows only from New Brunswick to New England.

We have included renewable resources situated in Quebec, Nova Scotia, Prince Edward Island, and New England in our analysis. We have assumed that imports from New England will not be available until 2009.

The availability of renewable generators from other regions to contribute to the New Brunswick RPS is sensitive to the renewable policy developments in those regions. For example, the government of Nova Scotia is considering an RPS that would require about five percent of the province's electricity to be derived from renewables in 2010 (Nova Scotia Department of Energy 2004). If the RPS is adopted, which seems likely, it will affect the availability of renewable imports from Nova Scotia. The adoption of an RPS in Quebec could similarly constrain the available supply of renewable imports from that province.

We have limited the amount of imports from Nova Scotia to reflect the probability that the province will implement an RPS. Similarly, we have de-rated the available renewable supply from Prince Edward Island. Three states in New England have already implemented renewable portfolio standards, and it is possible that others will follow. We have de-rated the available renewable supply from New England accordingly.

Finally, as noted above in Section 4, we limit the amount of imports that can be used to comply with the RPS in each year. This import limit is imposed as a policy to ensure that sufficient renewable resources are developed within New Brunswick as part of the RPS. In this study we evaluate the cost impacts of two import scenarios. In the One Percent RPS and the One-Half Percent RPS scenarios, we assume that imports are allowed to make up no more than 20% of the total renewable energy in the RPS in any one compliance year. In the No Imports scenario, we modify the One Percent scenario by not allowing any imports be used to comply with the RPS.

5.5 Hydropower

New Brunswick Hydro

While New Brunswick has considerable technical potential for new hydropower projects, hydro development in the province will be restricted by permitting barriers and the high capital cost of new projects. An RPS will provide some economic incentive for new projects, but without additional incentives, hydropower is not expected to constitute a large portion of the province's renewable supply.

Eligible hydropower projects fall into two categories: redevelopments at existing hydro sites and new projects at undeveloped sites. Although redeveloping existing sites is usually less costly, the potential for such projects is rather limited. Significantly greater technical potential exists for new projects at undeveloped sites, though the costs of these projects can be prohibitive.

The International Energy Agency's Small Hydro Site database identifies more than 170 undeveloped sites in New Brunswick for potential new hydroelectric projects totaling over 500 MW of capacity (IEA 2004). Most of these sites are not cost effective, and only a few are likely to be developed given the implementation of an RPS.

We have assumed the maximum available capacity of new hydro projects to be equal to half of total capacity of the top-ranked 25 projects in the database. Our capital cost estimate is roughly equivalent to the median of the cost of these 25 projects. Capacity factors and other cost assumptions are adopted from a cost study of the New York RPS (NYDPS 2003).

Table 5.1 New Hydro Cost and Availability Assumptions

	2006	2009	2012	2015
Capital Cost ($/kW)	$3,900	$3.900	$3,900	$3,900
Fixed O&M ($/kW-yr)	$16.0	$16.0	$16.0	$16.0
Variable O&M ($/MWh)	$3.4	$3.4	$3.4	$3.4
Capacity Factor (%)	50%	50%	50%	50%
Levelized Cost ($/MWh)	$98.7	$101.1	$104.1	$110.3
Available Capacity (MW)	2	6	10	10
Available Energy (GWh)	9	26	44	44

Costs are in real terms, except for levelized costs, which have been put into nominal terms.

The potential for hydro redevelopments in New Brunswick appears to be rather limited, and we have assumed a maximum available capacity of twoMW.[4] We have adopted cost figures and capacity factors from other RPS analyses.

Table 5.2 Hydro Redevelopment Cost and Availability Assumptions

	2006	2009	2012	2015
Capital Cost ($/kW)	$2,456	$2,456	$2,456	$2,456
Fixed O&M ($/kW-yr)	$6.1	$6.1	$6.1	$6.1
Variable O&M ($/MWh)	$0	$0	$0	$0
Capacity Factor (%)	45%	45%	45%	45%
Levelized Cost ($/MWh)	$68.5	$69.1	$69.9	$74.2
Available Capacity (MW)	0.5	1	1.5	2
Available Energy (GWh)	2	4	6	8

Costs are in real terms, except for levelized costs, which have been put into nominal terms.

Québec Hydro

Quebec is blessed with superior hydro resources, and several new projects, both large and small, are in the planning and construction stages.

4 Based on Irving 2004.

Last year, Hydro Quebec issued an RFP for hydro projects of 50 MW or less. Three projects at existing dam sites were selected, totaling 75 MW, or 337 GWh of energy, at an average price of just 4.3 cents per kWh (CEA 2002). The projects are expected to be commissioned for operation in 2005-2006. The cost of these projects is consistent with Canadian cost estimates for small hydro projects, which typically range from 4.5 to 6 cents per kWh (ENS 2001).

Six other publicly owned sites have also been allocated for potential hydroelectric development. Hydro-Quebec estimates the potential capacity of these sites to be 34 MW (Quebec MNR 2003). While the cost of developing these sites is probably low relative to the cost of renewable electricity generated in New Brunswick, it is unknown how much, if any, of the generation from these sites will be exportable to the province, given transmission constraints and political factors.

The Quebec-wide potential for projects such as these is very large, with perhaps as many as 300 MW of sites that can potentially generate electricity for 5.0 cents per kWh or less. (Innergex). The extent to which potential sites are actually developed depends on economic and regulatory factors that are not likely to be substantially affected by the New Brunswick RPS. To be conservative, we have assumed that a limited amount of Environmental Choice Program-certified small hydro in Quebec will be available for export to New Brunswick: five MW in 2006, 15 MW in 2009, and 25 MW in 2012 and 2015. Cost and capacity factor assumptions are derived from a report by the Ontario Renewable Energy Task Force (Bolieau et al. 2002), VT RPS Study (Synapse 2003), and OEI 2003.

Table 5.3 Quebec Hydro Cost and Availability Assumptions

	2006	2009	2012	2015
Capital Cost ($/kW)	$1,903	$1,903	$1,903	$1,903
Fixed O&M ($/kW-yr)	$0	$0	$0	$0
Variable O&M ($/MWh)	$6.1	$6.1	$6.1	$6.1
Capacity Factor (%)	47.5%	47.5%	47.5%	47.5%
Levelized Cost ($/MWh)	$50.3	$49.8	$49.4	$52.5
Available Capacity (MW)	5	15	25	25
Available Energy (GWh)	21	62	104	104

Costs are in real terms, except for levelized costs, which have been put into nominal terms.

New England Hydro

The technical potential for the development of small hydro sites and upgrades of existing facilities in New England is considerable, particularly in Vermont and Maine. Studies done by the Idaho National Engineering and Environmental Laboratory (INEEL) indicate that there is technical potential in New England for 140 MW of hydro repowering and 412 MW of hydro development at existing dams (2003). We have not included new projects at undeveloped sites in our analysis due to the significant regulatory barriers that such projects would face and their higher capital costs.

Despite the substantial technical potential, hydroelectric development in New England has stagnated in recent years. The actual experience of hydro developers in the region indicates that most of the existing hydropower sites in the region are close to fully developed and have little exceedance, meaning that upgrades or repowering may not significantly improve their capacity.

We have adopted the New England hydropower cost and available capacity assumptions from the Vermont RPS study. These assumptions are based on the 2003 INEEL Hydropower Resource Economics Database. We have assumed that 25 percent of the available capacity in New England will be exportable to New Brunswick, starting in 2011.

Table 5.4 New England Hydro Cost and Availability Assumptions

	2006	2009	2012	2015
Capital Cost ($/kW)	2,505	2,505	2,505	2,505
Fixed O&M ($/kW-yr)	$20.9	$20.9	$20.9	$20.9
Variable O&M ($/MWh)	$4.7	$4.7	$4.7	$4.7
Capacity Factor (%)	53.1%	53.1%	53.1%	53.1%
Levelized Cost ($/MWh)	$67.9	$72.1	$76.5	$81.2
Available Capacity (MW)	0	19	42	42
Available Energy (GWh)	0	88	195	195

Costs are in real terms, except for levelized costs, which have been put into nominal terms.

5.6 Biomass

New Brunswick Biomass

The potential for new biomass projects in New Brunswick is limited by the lack of readily available biomass fuel. The most promising application for new projects is at pulp and paper mill facilities where it may be possible to obtain sufficient feedstock for a moderately sized facility.

The newest utility-scale biomass facility in New Brunswick is a pulp and paper cogeneration facility that began operating in 1997. The 45 MW Fraser Papers plant in Edmundston generates steam for use at local mills and sells most of its electric output to New Brunswick Power. The plant was built at a cost of $135 million (American Printer 1997).

The province may have potential for about two new biomass projects at pulp and paper facilities (Irving 2004). These projects would probably be similar to the Fraser Papers cogeneration unit in Edmundston in that the steam output would be used on site and most of the electricity output would be sold to New Brunswick Power.

Cheminfo Inc. conservatively estimates the cost of a 15 MW biomass cogen facility to be about $50 million (1999). This is slightly higher than the cost of the Fraser Papers facility on a dollars per kilowatt basis. We have assumed that two new biomass cogen plants of 15 MW can be developed to meet the New Brunswick RPS at a cost of $45 million each. We estimate that the cost of fuel for these facilities will be $2.50 per mmBtu.[5] Other cost assumptions are derived from previous RPS studies in the Northeastern U.S. We have assumed that the plant heat rate, net of the fuel that would be required to generate steam, is 5,500 Btu/kWh (Neill and Gunter 2004 and Irving 2004).

Table 5.5 Biomass Cost and Availability Assumptions

	2006	2009	2012	2015
Capital Cost ($/kW)	$3,000	$3,000	$3,000	$3,000
Fixed O&M ($/kW-yr)	$57.9	$57.9	$57.9	$57.9
Variable O&M ($/MWh)	$3.6	$3.6	$3.6	$3.6
Capacity Factor (%)	85%	85%	85%	85%
Fuel Cost ($/MMBtu)	$2.5	$2.5	$2.5	$2.5
Heat Rate (Btu/kWh)	5,500	5,500	5,500	5,500
Levelized Cost ($/MWh)	$71.9	$72.7	$73.8	$78.3
Available Capacity (MW)	0	15	30	30
Available Energy (GWh)	0	112	223	223

Costs are in real terms, except for levelized costs, which have been put into nominal terms.

Québec Biomass

In contrast to New Brunswick, Quebec has significant amounts of surplus wood residue. According to the Canadian Forest Service, the province had 30.5 percent of Canada's surplus wood residue in 1998 – more than 1.6 million bone-dried tones (BDt), compared to just 0.18 million BDt in New Brunswick (CFS 1999). In April 2003, Hydro-Quebec issued an RFP for 100 MW of new biomass capacity. It has awarded two contracts totaling 39 MW, and additional projects are pending. The two projects which received awards are both cogen projects. The average price of electricity of the two contracts is 6.7 cents per kWh (Hydro-Quebec 2004).

We estimate that 10 MW of biomass cogeneration will be available to the New Brunswick RPS in 2006, with an additional 10 MW becoming available in both 2009 and 2012. We have assumed that capital costs for these projects will be lower than their New Brunswick counterparts because of their slightly larger size.

[5] The cost of fuel for the Fraser facility is between $12 and $26 per ton (Fraser 2004). Assuming fuel at $25 per ton and a heat content of 10 mmBtu/ton yields a fuel input cost of $2.50/mmBtu.

Table 5.6 Quebec Biomass Cost and Availability Assumptions

	2006	2009	2012	2015
Capital Cost ($/kW)	$2,800	$2,800	$2,800	$2,800
Fixed O&M ($/kW-yr)	$57.9	$57.9	$57.9	$57.9
Variable O&M ($/MWh)	$3.6	$3.6	$3.6	$3.6
Capacity Factor (%)	85%	85%	85%	85%
Fuel Cost ($/MMBtu)	$2.5	$2.5	$2.5	$2.5
Heat Rate (Btu/kWh)	5,500	5,500	5,500	5,500
Levelized Cost ($/MWh)	$68.6	$69.2	$70.1	$74.3
Available Capacity (MW)	10	20	30	30
Available Energy (GWh)	74	149	223	223

Costs are in real terms, except for levelized costs, which have been put into nominal terms.

New England Biomass

New England is currently home to 785 MW of operating biomass capacity (REPiS 2004). According to the eligibility requirements in the proposed RPS legislation, increases over the baseline generation levels of vintage units can be used to meet the RPS. In our analysis of the proposed Vermont RPS, we assumed that 36 MW of incremental capacity from existing biomass plants would be able to meet the state's RPS. Since the Vermont RPS has not been implemented, and existing biomass plants are not eligible resources in other New England renewable portfolio standards, it is possible that much of the available incremental generation could be exported to New Brunswick, given proper revenue incentives and transmission capability.

We assumed that half of the incremental generation from existing plants in New England would be available to contribute to New Brunswick's RPS. We do not expect new biomass projects in New England to contribute to the RPS. Many of these projects will likely be co-firing applications that do not qualify as renewable resources under the certification criteria of the Environmental Choice Program.

We assume that there will be no capital cost associated with this generation, because the plants are already constructed and operating. Finally, we assume that these plants will have the same fixed O&M, variable O&M and fuel costs as biomass plants in New Brunswick.

Table 5.7 New England Biomass Cost and Availability Assumptions

	2006	2009	2012	2015
Capital Cost ($/kW)	—	—	—	—
Fixed O&M ($/kW-yr)	$57.9	$57.9	$57.9	$57.9
Variable O&M ($/MWh)	$3.6	$3.6	$3.6	$3.6
Capacity Factor (%)	77%	77%	77%	77%
Fuel Cost ($/MMBtu)	$2.5	$2.5	$2.5	$2.5
Levelized Cost ($/MWh)	$34.5	$36.6	$38.9	$41.2
Available Capacity (MW)	0	18	18	18
Available Energy (GWh)	0	120	120	120

Costs are in real terms, except for levelized costs, which have been put into nominal terms.

Other Biomass Technologies

We have excluded from our analysis certain biomass technologies that we believe will not be cost effective contributors to the RPS. These include biomass gasification, direct biomass combustion, and repowering of coal plants to burn biomass. Given biomass feedstock constraints, we do not expect the costs of these technologies to be competitive with other renewable resources during our study period.

5.7 Landfill Gas

Of the six landfills in New Brunswick, perhaps three are of sufficient size to support economically viable landfill gas (LFG) energy projects. Both the Fredericton and Westmoreland landfills have over one million tonnes of waste in place (WIP), and the Red Pine landfill in northeastern New Brunswick is nearing the one million tonne mark. While the Fredericton landfill utilizes a garbage baling system that does not facilitate LFG production, the Westmorland and Red Pine are suitable candidates for LFG energy project development. The developers of the Red Pine landfill previously considered installing an LFG collection system, and it seems likely that such a project will eventually be commenced (NB Department of Environment 2004).

We have included one MW of landfill gas electricity potential from each of these two landfills in our New Brunswick renewable supply. We assumed that these projects would come online by 2009. We have adopted the major cost and performance assumptions pertaining to small landfill gas energy projects from the VT RPS study (Synapse 2003).

Though potential for landfill gas energy projects exists in both Quebec and New England, we have limited our supply analysis to landfills situated within New Brunswick. Because of the small size of LFG projects, we assumed that the electricity they generate would be used to meet load within their respective province or region.

Table 5.8 Landfill Gas Cost and Availability Assumptions

	2006	2009	2012	2015
Capital Cost ($/kW)	$2,120	$2,036	$1,952	$1,952
Fixed O&M ($/kW-yr)	$0	$0	$0	$0
Variable O&M ($/kWh)	$18.4	$18.4	$18.4	$18.4
Capacity Factor (%)	90%	90%	90%	90%
Levelized Cost ($/MWh)	$51.5	$51.1	$50.8	$53.9
Available Capacity (MW)	0	1	1	2
Available Energy (GWh)	0	8	8	16

Costs are in real terms, except for levelized costs, which have been put into nominal terms.

5.8 Wind

New Brunswick Wind

Atlantic Canada is blessed with exceptionally high-quality wind regimes. The combination of very cold weather and strong winter winds creates very high wind densities, which result in favorable capacity factors for wind projects. The large untapped potential of wind energy in New Brunswick, combined with the relative lack of availability of other renewable resources, will likely make wind the dominant resource in the RPS.

In December 2003, New Brunswick Power issued an RFP for 20 MW of new wind capacity. The RFP represents the first phase of the utility's plan to acquire 100 MW of capacity from new renewable projects by 2010.

Because of the prominent role of wind energy in the RPS, the amount of wind energy potential in the province will likely drive the RPS target levels. Thus, it is important to approximate the provincial potential as accurately as possible. Although there have been no public studies of the province's wind energy potential, wind developers in New Brunswick and Nova Scotia estimate that 350 to 400 MW of wind projects could be economically developed along the coastal areas of New Brunswick (Barrington Wind Energy and Eastern Wind Power 2004).

The amount of wind that can be installed in New Brunswick may be limited by the ability of the other generation and transmission facilities to support it. Because of its intermittent nature, wind generation needs to be balanced by conventional resources to maintain a stable electricity supply and meet customer loads in all hours. Also, as wind provides an increasing share of the total energy generated on a system, there is a risk of creating grid stability problems.

The summer period may be the most challenging time for integrating wind into the New Brunswick system, because that is when conventional plants are typically down for maintenance and hydro facilities are operating with lower water reserves. However, due to weaker wind patterns in the summer, capacity factors of wind projects will be much lower in the summer, making it easier for the electricity grid to accommodate the wind generation capacity. Furthermore, there are several actions that can be taken and modifications that can be made to the electric grid to allow for increased integration of wind. These issues are discussed in more detail in Appendix A of this study.

Four hundred megawatts of wind capacity would represent about 12 percent of the current peak winter load and 22 percent of peak summer load in New Brunswick. The New Brunswick grid should be sufficiently robust to sustain at least this amount of wind capacity, and possibly more. Potential imports of wind energy from neighboring regions should not contribute to grid stability issues in New Brunswick, because their wind patterns are likely to be sufficiently different from those within New Brunswick.

In order to represent the New Brunswick wind potential in greater detail, we have divided the resource into three capacity factor groups: 30 percent, 34 percent, and 38 percent. We have assumed that 200 MW of wind capacity could be available by 2006, and that the total available potential will reach 400 MW by 2009. After 2009, we have assumed that the available wind resource will increase at the same rate as the province's electricity load, which should approximately reflect the growth rate of the province's generation capacity.

Typical project costs in Atlantic Canada have varied from $1,500 to $2,000 per installed kilowatt, inclusive of interconnection costs. We have assumed an all-in capital cost of $2,000 per kW, in 2006. Other cost assumptions are based on Smith et al 2000.

Table 5.9 Wind at 30% Capacity Factor Cost and Availability Assumptions

	2006	2009	2012	2015
Capital Cost ($/kW)	$2,000	$2,000	$2,000	$2,000
Fixed O&M ($/kW-yr)	$20.9	$20.9	$20.9	$20.9
Variable O&M ($/kWh)	$6.1	$6.1	$6.1	$6.1
Capacity Factor (%)	30%	30%	30%	30%
Levelized Cost ($/MWh)	$93.9	$96.0	$98.5	$104.6
Available Capacity (MW)	60	120	125	130
Available Energy (GWh)	158	315	328	342

Costs are in real terms, except for levelized costs, which have been put into nominal terms.

Table 5.10 Wind at 34% Capacity Factor Cost and Availability Assumptions

	2006	2009	2012	2015
Capital Cost ($/kW)	$2,000	$2,000	$2,000	$2,000
Fixed O&M ($/kW-yr)	$20.9	$20.9	$20.9	$20.9
Variable O&M ($/kWh)	$6.1	$6.1	$6.1	$6.1
Capacity Factor (%)	34%	34%	34%	34%
Levelized Cost ($/MWh)	$82.9	$84.4	$86.2	$91.4
Available Capacity (MW)	80	160	167	173
Available Energy (GWh)	238	477	496	516

Costs are in real terms, except for levelized costs, which have been put into nominal terms.

Table 5.11 Wind at 38% Capacity Factor Cost and Availability Assumptions

	2006	2009	2012	2015
Capital Cost ($/kW)	$2,000	$2,000	$2,000	$2,000
Fixed O&M ($/kW-yr)	$20.9	$20.9	$20.9	$20.9
Variable O&M ($/kWh)	$6.1	$6.1	$6.1	$6.1
Capacity Factor (%)	38%	38%	38%	38%
Levelized Cost ($/MWh)	$74.2	$75.1	$76.4	$81.0
Available Capacity (MW)	60	120	125	130
Available Energy (GWh)	200	399	416	433

Costs are in real terms, except for levelized costs, which have been put into nominal terms.

Nova Scotia Wind

Wind energy development in Nova Scotia has outpaced development in New Brunswick. The 30 MW Pubnico Point Wind Farm in Yarmouth is the first commercial scale wind facility in the province. In November 2003, Nova Scotia Power announced that it had entered into a 15-year contract with the project to purchase approximately 100 GWh of electricity at $7 million per year.

Nova Scotia's voluntary RPS and the likely implementation of the mandatory RPS will spur more development activity in the next several years. Despite the competing demand for wind energy created by the Nova Scotia RPS, the province still may have enough surplus wind generation to export to New Brunswick (Nova Scotia DOE 2004). We estimated that Nova Scotia would have 30 MW of wind capacity available to export in 2009 and 100 MW in 2012 and beyond. Cost assumptions are the same as those for projects in New Brunswick.

Table 5.12 Nova Scotia Wind Cost and Availability Assumptions

	2006	2009	2012	2015
Capital Cost ($/kW)	$2,000	$2,000	$2,000	$2,000
Fixed O&M ($/kW-yr)	$20.9	$20.9	$20.9	$20.9
Variable O&M ($/kWh)	$6.1	$6.1	$6.1	$6.1
Capacity Factor (%)	34%	34%	34%	34%
Levelized Cost ($/MWh)	$82.9	$84.4	$86.2	$91.4
Available Capacity (MW)	0	30	100	100
Available Energy (GWh)	0	89	298	298

Costs are in real terms, except for levelized costs, which have been put into nominal terms.

Prince Edward Island Wind

PEI recently committed to an RPS target of 15 percent by 2010. The Malpeque Wind Energy Project, which is planned near Malpeque Bay, may eventually encompass 75 MW of capacity. If the New Brunswick RPS creates lucrative export opportunities for PEI wind projects, it is likely that a large portion of the electricity generated from the Malpeque project and from future projects in the province will be exported to New Brunswick.

We estimated that 30 MW of wind capacity could be exported to New Brunswick in 2006, with similar uptake rates in the other snapshot years. Cost assumptions are the same as those for projects in New Brunswick.

Table 5.13 Prince Edward Island Wind Cost and Availability Assumptions

	2006	2009	2012	2015
Capital Cost ($/kW)	$2,000	$2,000	$2,000	$2,000
Fixed O&M ($/kW-yr)	$20.9	$20.9	$20.9	$20.9
Variable O&M ($/kWh)	$6.1	$6.1	$6.1	$6.1
Capacity Factor (%)	34%	34%	34%	34%
Levelized Cost ($/MWh)	$82.9	$84.4	$86.2	$91.4
Available Capacity (MW)	30	50	75	100
Available Energy (GWh)	89	149	223	298

Costs are in real terms, except for levelized costs, which have been put into nominal terms.

Québec Wind

The vast wind energy potential of Quebec is unrivalled in Canada. A recent report by Helimax Energy estimated that the province has 100,000 MW of economically viable wind energy potential situated within 25 kilometres of existing transmission lines (Helimax 2004). Recently, Hydro-Quebec began soliciting proposals for new wind projects in the province. The utility issued an RFP in 2002 for 1000 MW of wind energy to come online between 2006 and 2012 (Hydro-Quebec 2004a). Independent of the RFP, several projects are already in the planning or development stages, and it is reasonable to expect that wind project development will eventually exceed the 1000 MW Hydro-Quebec RFP by a significant margin.

The amount of wind energy that Hydro-Quebec will seek to export to other electricity markets is unclear. Quebec's proximity to New Brunswick and the ample intertie capacity between the two provinces suggest that New Brunswick would be a prime export market, should the RPS generate sufficient revenue for Hydro-Quebec's wind power. However, Hydro-Quebec may also seek to participate in the emerging RPS markets in New England and New York, particularly if electricity market prices in the Northeastern U.S. remain higher than those in Atlantic Canada.

Due to these uncertainties, we have conservatively assumed that 15 percent of the capacity that was solicited in the RFP will be available for export to New Brunswick until 2009. In 2015, we have assumed an additional 150 MW of capacity to be available.

Quebec's considerable land mass and relatively large transmission system can support wind farms that are on average larger than those that are likely to be developed in the Maritime provinces. Whereas project sizes are expected to average 20 to 30 MW in New Brunswick and Nova Scotia, Quebec is already home to a 100 MW wind farm that is the largest in Canada (CanWEA 2004) and other large-scale projects are currently under development.[6]

To account for these anticipated economies of scale, we have assumed that capital costs for wind projects in Quebec will be slightly lower than project costs in New Brunswick and Nova Scotia. We have also assumed that the projects in Quebec will have an average capacity factor of 34 percent.

[6] These include the Mount Copper and Mount Miller wind farms in Murdochville, with 108 MW of capacity between them (CANWEA 2004a). (http://www.canwea.ca/downloads/en/PDFS/march04.pdf)

Table 5.14 Quebec Wind Cost and Availability Assumptions

	2006	2009	2012	2015
Capital Cost ($/kW)	$1,800	$1,800	$1,800	$1,800
Fixed O&M ($/kW-yr)	$20.9	$20.9	$20.9	$20.9
Variable O&M ($/kWh)	$6.1	$6.1	$6.1	$6.1
Capacity Factor (%)	34%	34%	34%	34%
Levelized Cost ($/MWh)	$78.9	$79.9	$81.4	$86.4
Available Capacity (MW)	30	150	300	300
Available Energy (GWh)	89	447	894	894

Costs are in real terms, except for levelized costs, which have been put into nominal terms.

New England Wind

The recently implemented Connecticut and Massachusetts renewable portfolio standards have spurred wind development activity in New England. In the Vermont RPS cost study, we estimated that 825 MW of wind projects would be available in New England by 2015. If the status quo of relatively high wholesale electricity prices and elevated renewable energy premiums persists in New England, it is unlikely that wind developers will seek to establish export contracts with electricity suppliers in New Brunswick. Thus, we have assumed that only ten percent of the available wind capacity as estimated in the Vermont RPS report will be available for export to New Brunswick.

We assumed that the current production tax credit (1.8 ¢/kWh) will be available for those wind projects that are installed by 2006, but not for those installed in later years. This assumption makes levelized costs appear lower in 2006 compared to later years.

Table 5.15 New England Wind Cost and Availability Assumptions

	2006	2009	2012	2015
Capital Cost ($/kW)	$2,200	$2,200	$2,200	$2,200
Fixed O&M ($/kW-yr)	$20.9	$20.9	$20.9	$20.9
Variable O&M ($/kWh)	$6.1	$6.1	$6.1	$6.1
Capacity Factor (%)	30%	30.5%	31%	32%
Levelized Cost ($/MWh)	$84.4	$89.5	$95.0	$100.8
Available Capacity (MW)	0	47	83	83
Available Energy (GWh)	0	126	225	233

Costs are in real terms, except for levelized costs, which have been put into nominal terms.

Due to its higher cost and transmission constraints, we have not included offshore wind projects in our supply analysis.

5.9 Solar

While there is likely to be some development of photovoltaic systems in New Brunswick that are eligible for the RPS, these resources are likely to be much more expensive than other renewables, and to be developed for niche applications only, particularly on homes. We do not expect them to play a significant role in setting the renewable premium or affecting the RPS costs.

The Canadian Solar Industries Association estimates that the installed cost of a grid-connected PV system is between $10,000 and $20,000/kW. Solar PV systems would have to achieve a dramatic reduction in costs in the next ten years before they would have a significant impact on the costs of the RPS in New Brunswick.

Solar panels provide the most power during the summer when the solar resource is best[7] and solar energy production would peak, but this coincides with the lowest peak electric load in New Brunswick, thereby negating the traditional "peaking" advantage of solar energy.[8] For all these reasons, and to simplify our analysis, we have left solar resources out of this study.

5.10 Ocean Power

As New Brunswick residents know well, the Bay of Fundy is of great interest to tidal power developers. With the widest variation in tides of any site in the world, it represents enormous tidal potential. The capital cost of tidal power, however, is huge in comparison to conventional and even most renewable energy resources. Because a barrage, a dam-like structure across the tidal inlet, must be built, significant environmental concerns for marine life are another major barrier to tidal power. In addition, as with solar power, energy production from tidal power is not synchronized with peak electric load, since tidal power generation follows the lunar 12 hour and 25 minute day and not our 24 hour solar day. According to the "Renewable Energy in Canada – Status Report 2002," all of these considerations "reduce the prospects of significant near-term development of tidal power." (Natural Resources Canada 2002) Nova Scotia Power, the only Canadian utility with a tidal power facility, says that while the tidal power potential of the Bay of Fundy is "enormous…large scale tidal power is not yet economically and environmentally viable."

Wave power is also a technologically immature energy resource and faces significant barriers to commercialization, chiefly, cost. In a study by the Hawaiian government, wave energy developers were asked to estimate their per kWh cost to generate electricity. Their answers varied from 8.54 to 17.4 cents/kWh, while a Danish Energy Agency study predicted costs of 37.0 to 59.2 cents/kWh. (HI DBEDT 2002) Because most wave power experience is theoretical and not based on the installation of actual commercial projects, these estimates are highly speculative and likely optimistic. In addition, wave power has variable impacts depending on whether it is located on-shore or off. These impacts include increased or reduced shore erosion, disruption of marine ecosystems, reduced recreational opportunities, visual impacts and noise creation.

Another emerging ocean power technology that is neither wave nor tidal power, is being developed by a Canadian company called Blue Energy. The Davis Hydro turbine is one

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7 See the Atlas of Canada Solar Radiation – December and June Map at http://atlas.gc.ca/site/english/maps/archives/5thedition/environment/climate/mcr4077.

8 Most electric loads peak in the summer, meaning that solar power has an added benefit of producing the most power during the days with the greatest load. Since power is generally highest cost during these periods, the "peaking" advantage of solar makes it a more economical resource. Solar PV in New Brunswick, therefore, does not have this added economic advantage.

of several designs worldwide that will capitalize on the energy created by “tidal currents” or “tidal streams.”[9] It is a vertical axis turbine that rotates at a speed of no more than 25 rpm so that it is not dangerous to marine life. The turbine is also surrounded by a fence that keeps out larger animals that could get into the turbine. Since no barrage is needed, disruption of tidal flows is minimized. Despite these advantages, an environmental impact assessment would clearly be needed and cost is likely an issue. A recent project to install tidal current power in the East River Channel in New York City claims that it will generate power at a cost of 8.5 cents/kWh.[10] It remains to be seen, however, whether this cost is truly representative of most tidal current power projects. Tidal current power merits further review but without better information about cost and performance and the potential for the resource in New Brunswick it remains outside the scope of our analysis.

Given the present high economic and environmental costs (particularly for tidal power) and the highly speculative nature of future costs for the various types of ocean power, we assume that they will not figure into the mix of resources to meet the New Brunswick RPS. As such, we have left all types of ocean power out of our analysis.

5.11 Summary of Renewable Generation Available

Table 5.14 presents a summary of the renewable energy generation that would be available to New Brunswick under the assumptions described above. One of the most significant uncertainties in identifying the renewable energy available in New Brunswick is the amount of wind generation that the electricity grid can support. If the grid can support more wind than we have assumed here, then the renewable potential presented in Table 5.14 could be much higher.

Another significant uncertainty is the amount of renewable generation that might be available from imports. Each neighboring region has the potential for significant renewable generation, but also has a variety of constraints to selling that generation into the New Brunswick market. This includes potential constraints on transmission interties, potential constraints as a result of demand for the renewable generation in the neighboring electricity markets, and potential constraints in terms of documenting and accounting for the renewable generation attributes. Consequently, the actual amount of renewable generation available from neighboring regions could be significantly different than our estimates presented below.

[9] Perhaps one of the most thorough and recent assessments of tidal current power is Triton Consultants 2002.

[10] New York Times, by Ian Urbina, July 10, 2004. Cost converted to Canadian dollars using an exchange rate of 1.22.

Table 5.14 Potential Renewable Energy Available to New Brunswick

	2006 (GWh)	2009 (GWh)	2012 (GWh)	2015 (GWh)
New Brunswick				
Wind (30% CF)	158	315	328	342
Wind (34% CF)	238	477	496	516
Wind (38% CF)	200	399	416	433
New Hydro	9	26	44	44
Hydro Upgrades	2	4	6	8
Biomass	0	112	223	223
Landfill	0	8	8	16
Subtotal	**309**	**1341**	**1521**	**1582**
Imports				
Wind – Nova Scotia	0	89	298	298
Wind – PEI	89	149	223	298
Wind – Quebec	89	447	894	894
Wind – New England	0	132	233	233
Biomass – Quebec	74	149	223	223
Biomass – New England	0	120	120	120
Hydro – New England	0	88	195	195
Hydro – Quebec	21	62	104	104
Subtotal	**273**	**1230**	**2282**	**2365**
TOTAL	**582**	**2571**	**3803**	**3947**

6. The Mix of Renewables Supplying the RPS

6.1 The Renewable Supply and Demand

Figure 6.1 through 6.4 present the renewable supply curves for the New Brunswick RPS in 2006, 2009, 2012 and 2015. The supply curves include the costs (in $/MWh) and amounts (in GWh) of all eligible renewable sources that are likely to be available to comply with the NB RPS. The renewable sources are ranked from lowest to highest, in order to indicate which sources are likely to be used first to meet the RPS target. For all the figures, the x-axis was set to equal the same x-axis as Figure 6.4, in order to allow for comparison across the snapshot years.

Figures 6.1 through 6.4 also present the estimated avoided cost of electricity in the relevant years. The difference between the supply curve and the avoided cost indicates the renewable premium at different points along the curve.

The figures present the RPS demand for the scenario where the RPS target equals one percent per year and the imports are limited to a maximum of 20% of the total RPS. All of the renewable sources along the supply curve to the left of the demand curves are assumed to be used to comply with the RPS in each year.

Thus, the renewable supply curves below provide a quick summary of our results. The renewable premium for each resource in the curve is equal to the difference between the supply curve and the avoided cost line. The total additional cost of complying with the RPS is equal to the area within the supply curve, the avoided cost line, and the demand curve.

The supply curves also indicates how sensitive our results will be to different assumptions about renewable costs and the RPS demand. A relatively steep supply curve near the intersection with the demand curve suggests that the renewable premiums will be very sensitive to our assumptions. Conversely, a relatively flat supply curve near the intersection with the demand curve suggests that the renewable premiums will not be very sensitive to our assumptions.

Note that the amount of renewable generation available in 2006 is significantly less than in later years, because we have assumed that only 200 MW of wind will be available in New Brunswick by this time. The amount of renewable generation increases significantly in later years as a result of (a) additional time to develop the full potential for New Brunswick wind, (b) increased potential for imports over time, and (c) slightly more wind potential as the New Brunswick system gets larger.

Figure 6.1 Renewable Supply Curve for the New Brunswick RPS in 2006

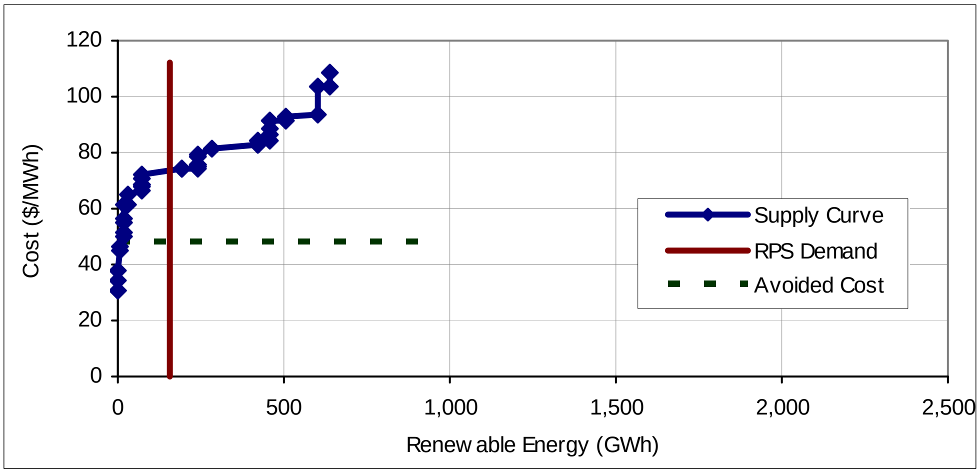


Figure 6.2 Renewable Supply Curve for the New Brunswick RPS in 2009

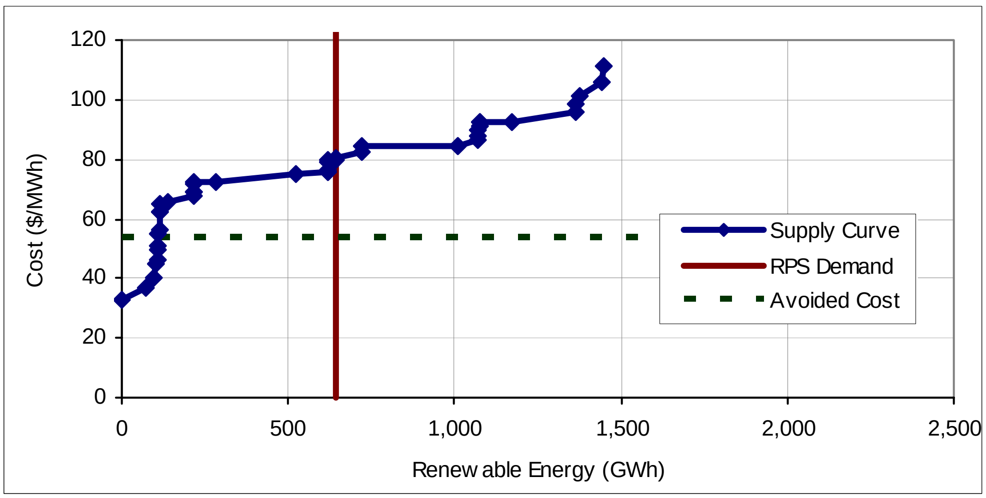


Figure 6.3 Renewable Supply Curve for the New Brunswick RPS in 2012

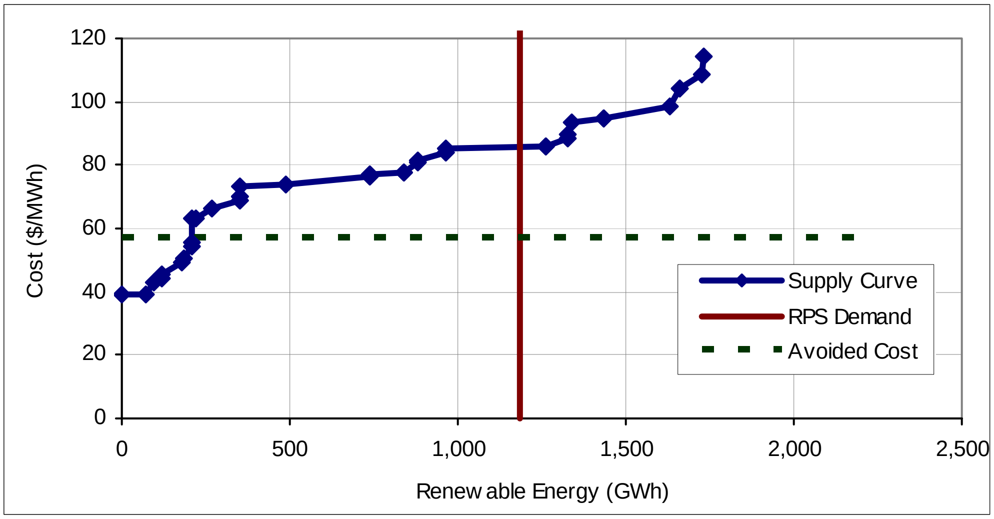
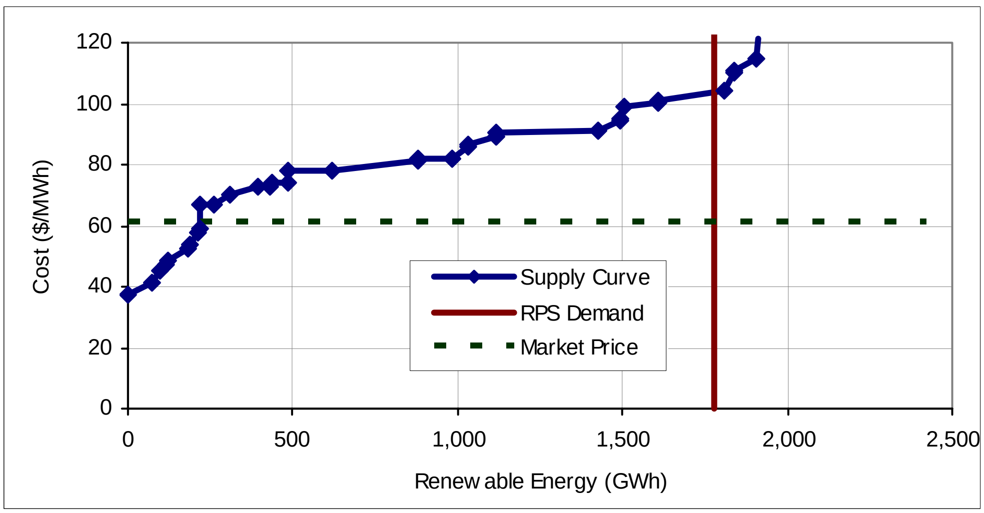


Figure 6.4 Renewable Supply Curve for the New Brunswick RPS in 2015

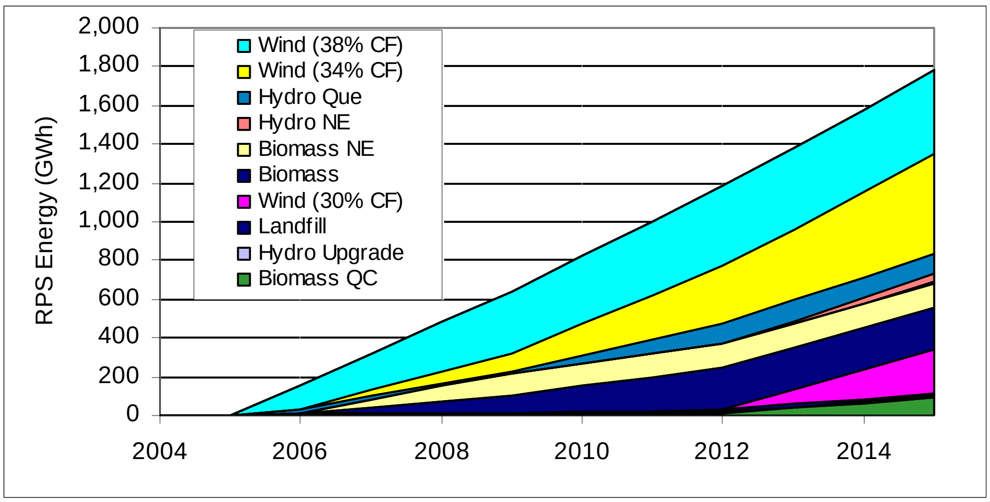


6.2 The Mix of Renewable Types used to Meet the NB RPS

Figure 6.5 presents the mix of the renewable sources that are expected to be used to comply with the New Brunswick RPS throughout our study period. It includes the mix of renewables under the scenario where the RPS target is one percent per year and the import limit is 20%. Figure 6.5 suggests that most of the RPS will be met with 38% capacity factor wind, 34% capacity factor wind, and relatively smaller amounts of biomass.

Note that the imported power only includes hydro from Québec and New England, and biomass from Québec and New England. Thus, the large potential for wind generation in the neighboring provinces is not utilized to meet the RPS, primarily as a result of the 20 percent import limit that we have imposed.

Figure 6.5 The Mix of Renewables Sources Supplying the New Brunswick RPS



7. Potential Cost Impacts of the New Brunswick RPS

7.1 New Brunswick Electricity Sales and Prices

In order to estimate the potential cost impact of a renewable portfolio standard, it is first necessary to forecast the estimated sales and cost of electricity in the absence of the RPS. The estimated RPS cost impacts will be relative to this baseline forecast.

Table 7.1 presents a forecast of electricity sales, costs and prices for the province of New Brunswick, through 2015. These "in-province" data include sales to wholesale customers within New Brunswick, but do not include any exports to neighboring regions. The electricity sales and costs forecasts were provided by New Brunswick Power, and are the same forecasts used in their model for estimating avoided costs (see Section 3).

Table 7.1 New Brunswick Electricity Sales, Costs and Prices

Year	In-Province Electricity Sales (GWh)	In-Province Electricity Costs (mil$)	Average In-Province Price ($/MWh)
2006	15,864	1,120	70.6
2007	16,020	1,168	72.9
2008	16,133	1,202	74.5
2009	16,067	1,236	76.9
2010	16,377	1,279	78.1
2011	16,617	1,328	79.9
2012	16,943	1,381	81.5
2013	17,263	1,437	83.2
2014	17,583	1,496	85.1
2015	17,805	1,533	86.1
2016	17,805	1,564	87.0

7.2 RPS Set at One Percent Per Year

Imports Limited to Twenty Percent

Table 7.2 and Figure 7.1 present the cost impacts of the RPS if the target is set at one-percent per year, and the imports are limited to 20 percent. They indicate that the RPS premium is expected to range from roughly $8/MWh to roughly $26/MWh.[11] The impact on retail costs is expected to be low. The average price impact is estimated to steadily rise to two percent in 2015, and then drop off significantly after that.

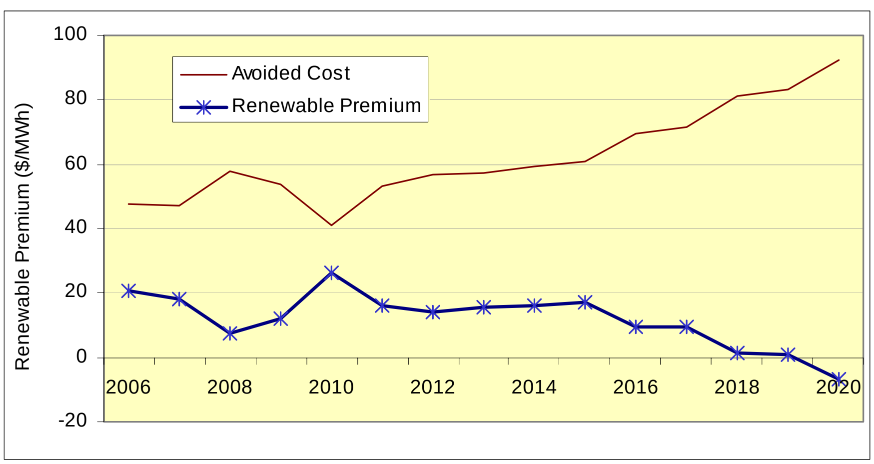
[11] All costs presented in this chapter are in nominal dollars.

Note in Figure 7.1 that the avoided cost curve and the renewable premiums are essentially mirror images of each other. The renewable generation costs only change moderately between years, but as avoided costs increase the renewable premium decreases, and vice versa. After 2015, the renewable premium declines significantly, primarily because the avoided costs increase with the addition of avoided capacity costs, and also because the RPS target stays constant after 2015.

Table 7.2 Cost Impacts: 1% RPS, 20% Import Limit

Year	In-Province Renewable Energy (GWh)	Avg Renew Premium ($/MWh)	Avg Renewable Premium Cost (M$)	Average Price Impact (%)
2006	159	20.5	3.2	0.3%
2007	320	18.3	5.9	0.5%
2008	484	7.6	3.7	0.3%
2009	643	12.2	7.8	0.6%
2010	819	26.4	21.6	1.7%
2011	997	15.9	15.8	1.2%
2012	1,186	13.8	16.4	1.2%
2013	1,381	15.8	21.8	1.5%
2014	1,582	16.1	25.4	1.7%
2015	1,781	17.1	30.5	2.0%
2016	1,798	9.7	17.4	1.1%
2017	1,816	9.4	17.0	1.1%
2018	1,835	1.3	2.4	0.2%
2019	1,853	0.9	1.7	0.1%
2020	1,872	-6.5	-12.2	-0.7%
2021	1,890	-7.3	-13.8	-0.8%

Figure 7.1 Renewable Premiums and Avoided Costs: 1% RPS, 20% Imports



Imports Not Allowed

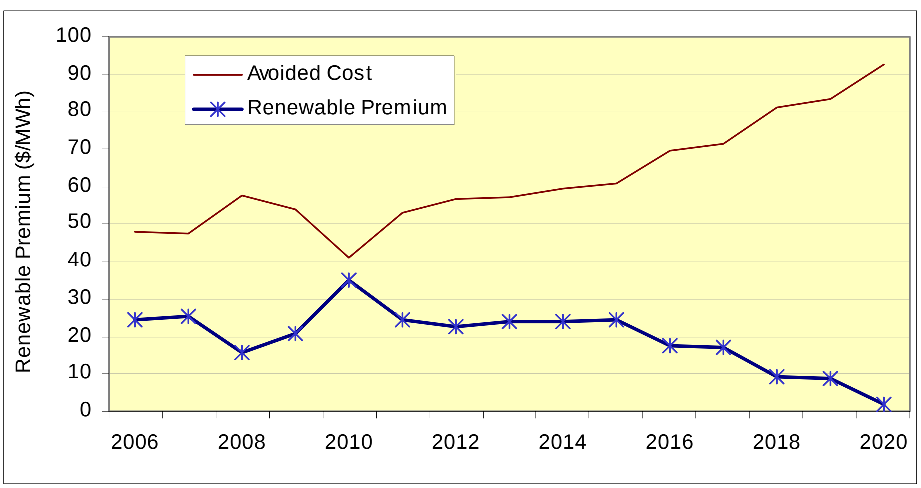
Table 7.3 and Figure 7.2 presents the cost impacts of the RPS if the target is set at one-percent per year, and no imports are allowed at all. Under these assumptions, the renewable premiums range from roughly $16/MWh to $35/MWh in the first ten years. The average price impact reaches roughly two percent by 2010 and nearly three percent by 2015.

In this case, we find that there may not be sufficient renewable resources within New Brunswick to satisfy the ten percent RPS target in that year. Under the renewable supply assumptions we use in this analysis, there would be a shortfall of 198 GWh in 2015, which is roughly 11% of the total target in that year. In practice, the renewable industry in New Brunswick may be able to develop enough generation by this time to meet the RPS target in this case where imports are excluded.

Table 7.3 Cost Impacts: 1% RPS, No Imports Allowed

Year	In-Province Renewable Energy (GWh)	Avg Renew Premium ($/MWh)	Avg Renewable Premium Cost (M$)	Average Price Impact (%)
2006	159	24.5	3.9	0.3%
2007	320	25.3	8.1	0.7%
2008	484	15.8	7.7	0.6%
2009	643	20.5	13.2	1.1%
2010	819	34.8	28.5	2.2%
2011	997	24.4	24.3	1.8%
2012	1,186	22.6	26.8	1.9%
2013	1,381	23.8	32.9	2.3%
2014	1,582	23.8	37.7	2.5%
2015	1,781	24.6	43.7	2.9%
2016	1,798	17.3	31.1	2.0%
2017	1,816	17.1	31.1	1.9%
2018	1,835	9.2	16.9	1.0%
2019	1,853	8.9	16.6	1.0%
2020	1,872	1.7	3.1	0.2%
2021	1,890	1.1	2.0	0.1%

Figure 7.2 Renewable Premiums and Avoided Costs: 1% RPS, No Imports Allowed



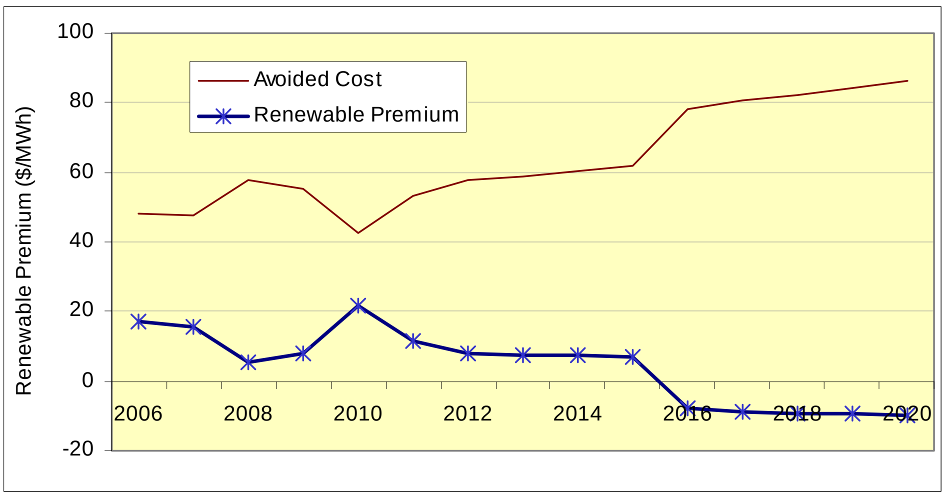
7.3 RPS Set at One-Half Percent Per Year

Table 7.4 and Figure 7.3 present the cost impacts of the RPS if the target is set at one-half percent per year and imports are limited to 20 percent. In this case, the renewable premiums range between $5/MWh and $22/MWh, and the impacts on retail electric costs are well below one percent per year in all years.

Table 7.4 Cost Impacts: 0.5% RPS, 20% Import Limit

Year	In-Province Renewable Energy (GWh)	Avg Renew Premium ($/MWh)	Avg Renewable Premium Cost (M$)	Average Price Impact (%)
2006	79	17.0	1.3	0.1%
2007	160	15.4	2.5	0.2%
2008	242	5.3	1.3	0.1%
2009	321	8.0	2.6	0.2%
2010	409	21.5	8.8	0.7%
2011	499	11.6	5.8	0.4%
2012	593	7.9	4.7	0.3%
2013	691	7.6	5.3	0.4%
2014	791	7.3	5.8	0.4%
2015	890	7.1	6.3	0.4%
2016	899	-7.7	-7.0	-0.4%
2017	908	-8.9	-8.1	-0.5%
2018	917	-9.1	-8.4	-0.5%
2019	926	-9.4	-8.7	-0.5%
2020	936	-9.9	-9.3	-0.5%
2021	945	-27.3	-25.8	-1.5%

Figure 7.3 Renewable Premiums and Avoided Costs: 0.5% RPS, 20% Imports



7.4 WPPI and RPPI Not Extended

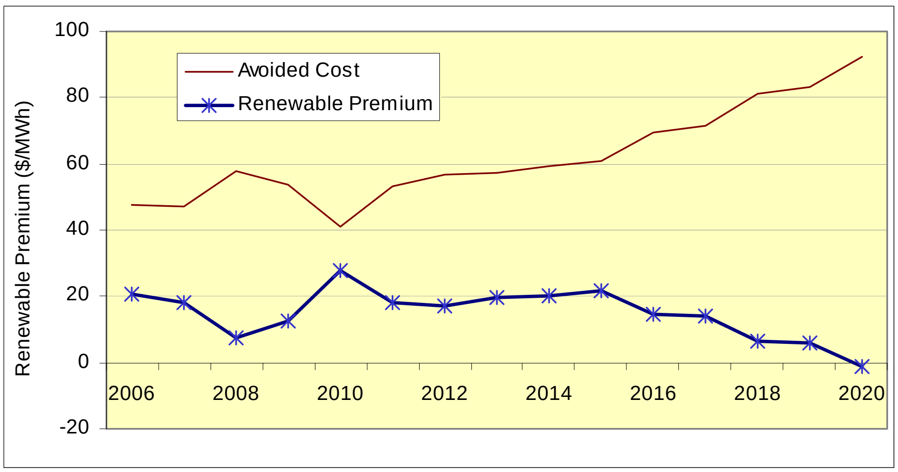
AS described above in Section 5.3 we have assumed that the WPPI and RPPI are extended through at least 2015. At the time of this analysis, these policies only applied to renewable generators built prior to 2011, but it was expected that they would be extended well beyond this date. This final scenario assesses the cost impacts of the RPS if the WPPI and RPPI are not extended after all. It is based on the first scenario presented above, the One Percent RPS with a 20% limit on imports.

Table 7.5 and Figure 7.4 present the results. They indicate, as expected, that renewable costs increase slightly. The renewable premium reaches a peak price of roughly $28/MWh and the average price impact peaks at 2.5% in 2015.

Table 7.5 Cost Impacts: WPPI and RPPI Not Extended

Year	In-Province Renewable Energy (GWh)	Avg Renew Premium ($/MWh)	Avg Renewable Premium Cost (M$)	Average Price Impact (%)
2006	159	20.5	3.2	0.3%
2007	320	18.3	5.9	0.5%
2008	484	7.6	3.7	0.3%
2009	643	12.6	8.1	0.7%
2010	819	27.8	22.8	1.8%
2011	997	18.3	18.3	1.4%
2012	1,186	17.1	20.2	1.5%
2013	1,381	19.6	27.0	1.9%
2014	1,582	20.3	32.1	2.1%
2015	1,781	21.8	38.7	2.5%
2016	1,798	14.4	25.9	1.7%
2017	1,816	14.2	25.8	1.6%
2018	1,835	6.2	11.5	0.7%
2019	1,853	5.9	10.9	0.7%
2020	1,872	-1.4	-2.7	-0.2%
2021	1,890	-2.1	-4.0	-0.2%

Figure 7.4 Renewable Premiums and Avoided Costs: WPPI & RPPI Not Extended



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Appendix A: Wind Power and Grid Stability

Factors Affecting the Wind Potential in New Brunswick

In determining the practical wind power potential for New Brunswick there are several factors to consider:

- The extent of the physical wind resources.
- The potential for import or export of wind generated electricity.
- The magnitude and pattern of the electricity loads.
- The interaction of wind with other electricity resources.
- The stability of the electrical system with the addition of wind generation.

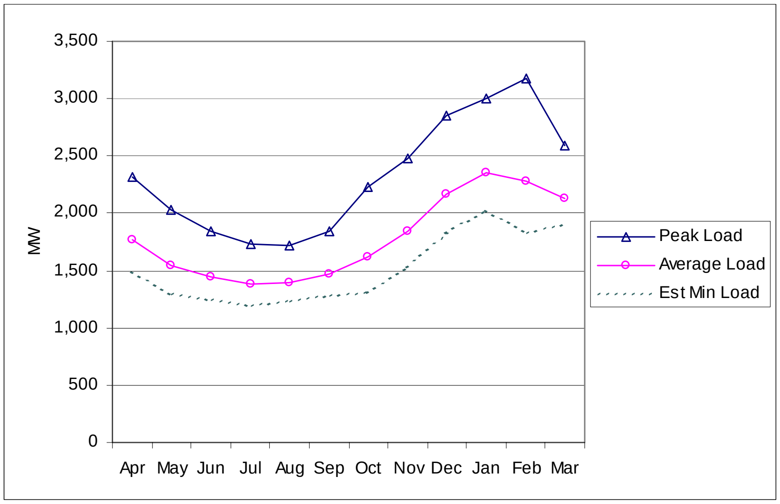
The first two issues are addressed in Section 5 of this study. In this appendix we will look at the remaining issues.

Electricity Load Patterns

The forecast peak load in NB for 2004-05 is 3,179 MW. The forecasted average load is 1,768 MW. The peak load is expected to grow 13% in ten years to a level of 3,591 MW.[12]

The graph below shows the annual pattern of peak and average loads. Note that NB is currently very much winter peaking, with the summer peak loads about half those of the winter. The variation in average loads is not as great, with the average load in July about 58% that of the January load. The minimum loads depend on a variety of factors but are closer to the average than the peak loads are above the average.[13]

Figure A.1 NB Monthly Peak and Average Loads for 2004-2005

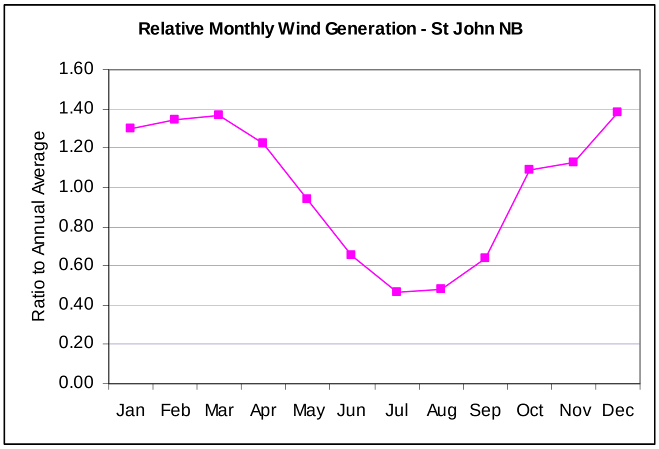


[12] From "zz - DisCo Requirements (031118).xls" created by Ian R MacPherson.

[13] The estimated minimum load is shown here based on a typical relationship between peak, average and minimum loads for other utilities.

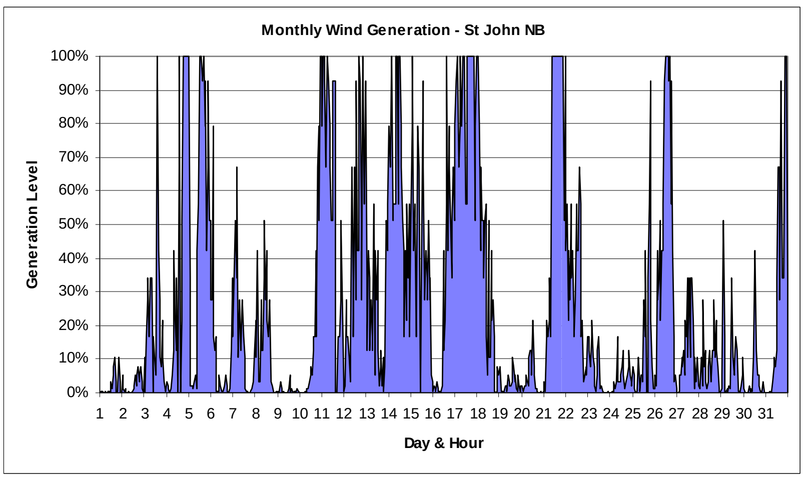
Although wind power is available during all times of year, it tends to be most available in this part of Canada in the Winter and early Spring which corresponds well to the NB electrical loads. The graph below shows the relative monthly wind power based on the average wind speeds for Saint John NB. Note that wind energy in May and Sep is close to the annual average, whereas the summer period is below average and the winter above.

Figure A.2 Relative Monthly Wind Energy for Saint John New Brunswick



The basic electrical system challenge of wind is its variability. Wind generation varies by month, day, hour and sometimes from minute to minute. The same can be said for electrical load, but the wind variations are less uniform and predictable. The chart below illustrates the pattern of hourly generation for a single month based on hourly data for Saint John NB. Note that although there are periods of high and low wind generation, even within those periods there can be substantial variations.

Figure A.3 Illustrative Hourly Wind Generation at St John NB (for Jan 2001)



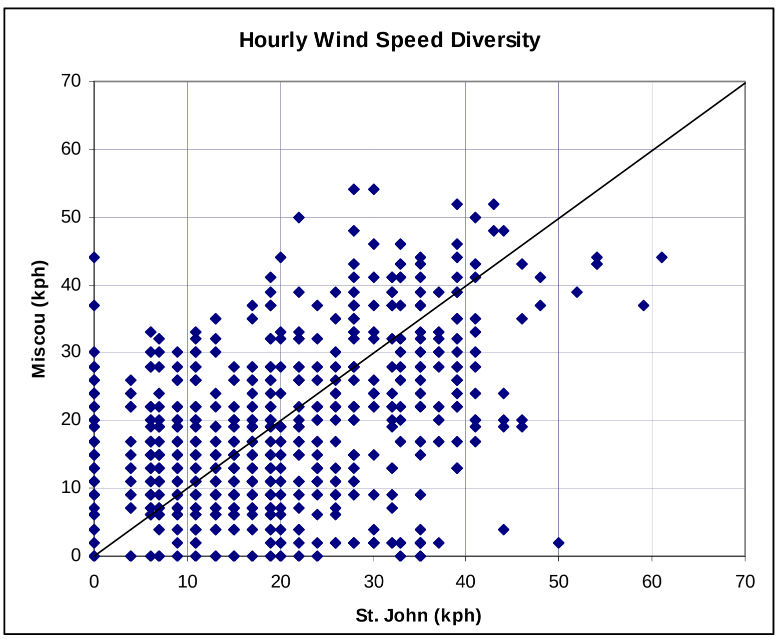
Source: Hourly wind data obtained from the Meteorological Service of Canada

Interaction of Wind with Other Electricity Resources

Thus although wind generation is to some extent predictable, it is not constant. This means that wind generation needs to be balanced by conventional resources to maintain a stable electricity supply. Some of those balancing resources need to be quick response to offset the short-term variability, and others can have a longer response time appropriate to the longer term variations. The exact nature of those balancing resources depends on a number of factors with an appropriate balance of economics and reliability and will be discussed more in the following section. Note though that wind is not unique in requiring balancing resources, all electrical systems require quick response resources to respond to changes in loads and live reserves to offset unexpected power plant outages.

The ability of wind to meet electric demands in any one point in time also depends upon the location of the wind turbines. Although wind power is dependent on weather patterns, additional wind stations in different locations introduce diversity and reduce the short-term local variations. This diversity smoothing effect depends on how far apart the stations are, but can be significant for the short-term variations. Figure 4 below illustrates the wind speed correlation and diversity for two locations on the north and south coasts of New Brunswick about 400 km apart. Each point represents one hour and shows the wind speed at two separate locations. The correlation for this period (March 2000) is at 0.40 which gives a substantial amount of diversity. As greater amounts of wind are added to a system, the location of the turbines and diversity of the wind resources becomes more important.

Figure A.4 Hourly Wind Speed Correlation for Two Sites in NB (Mar 2000)



Note that some points in the above graph represent multiple hours.

The Stability of the Electrical Grid With the Addition of Wind Generation

The addition of any new generating resource requires transmission system modifications to carry the new energy. In that regards, wind is like any other new power plant. However wind resources introduce new operating challenges because of its inherent variability. Other resources may be needed to balance that additional variability.

The problem of managing an electrical power system is to keep the generation and loads in balance in real-time. Loads although they have a regular daily pattern are not fully predictable and have minute-to-minute and hour-to-hour variations. In addition, peak loads on hot summer days can be very unpredictable. Uncertainties also exist in conventional generation where individual units can have sudden full or partial outages. Other uncertainties exist in transmission where a line could totally fail for a variety of reasons. Thus the variability of wind resources just adds another uncertainty to already existing ones. That uncertainty has a cost, but it fits within the standard framework of electric system operation.

A number of studies have looked at the additional system costs incurred because of the natural variability in wind generation. There are basically three time scales of interest with different types of solutions and costs:

- Unit-Commitment: horizon of 1 day to 1 week. Units made ready to provide generation as needed. Usually this is done with a reserve margin of about 15% above the predicted load.
- Load-Following: horizons of 5-10 minutes to 1 hour. On-line ready response units to adjust generation to match changes in load or wind generation.
- Regulation: horizon is minute to minute in increments of 1-5 seconds. This is provided by units with Automatic Generation Control (AGC) that can respond rapidly to follow very short term imbalances between load and generation.

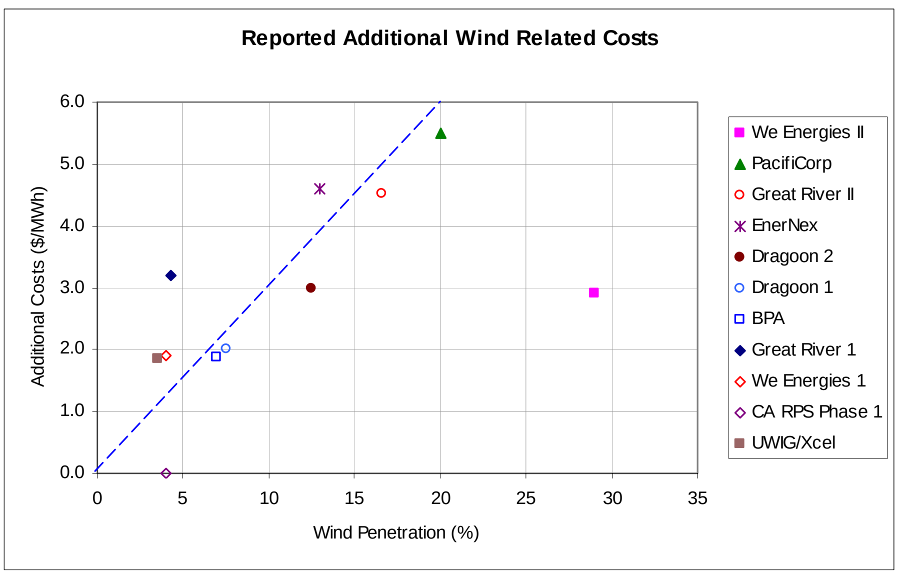
The table below summarizes the results from a number of studies to date. The additional system costs associated with levels of wind generation from 3.5% to 29% range from 1.47 to 5.50 $/MWh. The largest cost component appears to be associated with unit commitment of additional reserve resources. More accurate wind forecasts will reduce these costs. Although these additional costs do vary by system and circumstances, the total impacts are fairly modest compared to the total cost of power.

Table A.1 Summary of Wind Power Impact Studies [14]

		Additional Wind Associated Costs ($/MWh)			
Study	Relative Wind Penetration (%)[15]	Regulation	Load Following	Unit Commitment	Total
BPA	7	0.19	0.28	1.00-1.80	1.47-2.27
CA RPS Phase 1	4	0.17	na	na	na
Dragoon 1	7.5				2.0
Dragoon 2	12.5				3.0
EnerNex	13	0.23	0	4.37	4.60
Great River 1	4.3				3.19
Great River II	16.6				4.53
Hirst	0.06-0.12	0.05 - 0.30	0.70 - 2.80	na	na
PacifiCorp	20	0	2.50	3.00	5.50
UWIG/Xcel	3.5	0	0.41	1.44	1.85
We Energies 1	4	1.12	0.09	0.69	1.90
We Energies II	29	1.02	0.15	1.75	2.92

The figure below shows the cost increases shown in the above studies as wind penetration increases within a region. As expected the additional system costs increased with greater wind capacity. We have fitted a line showing increasing integration costs as the fraction of wind resources increase. Actual costs depend on the specific system configuration and are also likely to decline as experience is gained.

Figure A.5 Comparison of Additional Wind Related Costs from Various Studies



[14] Original from Smith 2004. Additions made by Synapse.

[15] Wind penetration is typically represented as maximum wind capacity as a percentage of the peak system load. It is not uncommon for wind generation to exceed that fraction during times when loads are less than peak.

A recent wind integration study was performed by GE Energy for NYS ERDA and released as a draft report in February 2005. This study looked at the effects of integrating 3,300 MW of wind into a system with a peak load of 34,704 MW (~10% wind fraction). One zone had a wind fraction of 36%. They concluded that this amount of wind capacity could be managed without any significant changes in the current system. One thing they do mention is that wind generation may need to be curtailed during some periods of low system loads and high wind capacity to prevent the uneconomic shutdown of critical base load generation. The report does not provide specific costs of wind integration impacts, however they do report variable cost reductions of $48/MWh for wind generation which implicitly includes both the benefits of energy savings and the costs of wind integration.

Electric systems with substantial amounts of energy-limited hydro resources are a very good match for wind generation since hydro plants incur low costs by being on-line and can respond very rapidly to changes in loads. The wind generation also serves to conserve limited hydro energy. One can almost view hydro as a very efficient energy storage system when paired with wind.

In addition, stability issues can be addressed by utilizing the wind generators less than their full potential in those times when grid stability is a concern. For example, if loads are low and balancing resources are not available or are too expensive, then the amount of wind power can be limited by turning off (or down) the wind generators until conditions improve. This may reduce to some small extent the total annual energy delivered from the wind resources, but system stability is maintained.

How much wind resource can be used reliably in an electrical system depends on a number of factors, and is also subject to the consideration that the system can be modified to allow for more wind generation. The British Wind Energy Association estimates that system fluctuations associated with wind do not exceed normal system fluctuations until wind exceeds 20% of the current supply. Eric Hirst (Hirst 2004) recently modeled a 4,600 MW system in the US and found that 1,000 MW of wind (roughly 22%) could be added with few system violations. Wind generation is functioning successfully as a very large fraction of generation in parts of Europe. For example, in the Eltra area of Denmark (Pendersen 2003) the electricity system has a peak load of 3,685 MW and the wind power capacity is 2,315 MW (roughly 63% of peak load).

The New Brunswick peak load forecast for the 2005-06 fiscal year is 2,964 MW and the generating resources for that period are predicted to be about 4,000 MW. Applying a rough 10% penetration level to the 2005-06 load gives 300 MW of possible wind generation. At a 20% penetration level the amount of possible wind generation increases to 600 MW, but are likely to incur additional system costs in the order of 7.5 Cdn$/MWh for the wind generation. But specific technical analysis would be required to arrive at a more precise value. Wind penetration at higher levels is possible as shown by some European examples, but more experience and technical analysis would be required to determine the feasibility and costs.

The wind resources should include features that aid grid stability such as:

1. Power block curtailment ability,
2. Maximum power limitation,
3. Ramp rate control,
4. Frequency control,
5. Low voltage ride through capability.

But these requirements need to be balanced between wind generator and system resources in a cost effective manner.

Summary

On an annual basis wind energy is a good match to New Brunswick loads since it is most available in the Winter months when loads are high. In addition there are a number of good wind resource areas along the coast.

Addition of substantial amounts of wind resources to the electrical system in New Brunswick appears both technically and economically feasible. As the fraction of wind generation increases there will be additional, but modest, system costs to compensate for the variability in wind generation.

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