Integrated Resource Plan 2014

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1. INTRODUCTION

Since 1920, NB Power has provided New Brunswick with a secure, reliable and competitively priced supply of electricity. Over the years, the supply mix has grown from a small, five megawatt (MW) hydroelectric generating station in Musquash to one of the most diverse systems in North America, which currently consists of 13 nuclear, hydro, coal, oil and diesel powered stations, as well as power purchase agreements from various privately owned renewable and natural gas-powered facilities.

NB Power has more than 6,800 kilometres (km) of transmission lines, and over 20,000 km of distribution lines. NB Power is committed to providing safe, reliable and efficient power to its more than 394,000 direct and indirect customers in New Brunswick.

NB Power's corporate mission, vision and values:

Mission	Vision	Values
Proudly Serve our Customers by Being Top Quartile	Sustainable Electricity	• Safety • Quality • Innovation

The mission, vision and values define the long-term strategy for NB Power. The mission describes the purpose of the organization, while the vision paints a picture of what the desired future will look like. The values represent what is important to the company and how employees operate and behave while working with internal and external stakeholders to conduct business and work towards achieving the corporation's mission and vision.

NB Power's mission has been, and continues to be, customer focused. The relationships with customers and stakeholders constantly evolve to enhance this focus. By continuously demonstrating its core values of safety, quality and innovation, NB Power will become top quartile for the benefit of all customers. However, it is recognized that the electricity industry is changing, and as a result, NB Power has changed its vision to reflect a new priority: *Sustainable Electricity.*

The Canadian Electricity Association (CEA) defines sustainable electric utilities as those "pursuing innovative business strategies and activities that meet the needs of members, stakeholders and the communities in which we operate today, while protecting and enhancing the human and natural resources that will be needed in the future."[1]

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[1] http://www.sustainableelectricity.ca/en/guiding-principles/policy.php

At NB Power, sustainability is factored into every decision and every plan for the future. It's about balancing efforts to deliver competitively priced electricity while maintaining long-term corporate health. It's about harnessing the power of renewable energy sources and safeguarding the environment by moving away from fossil fuels.

Sustainability represents goals embraced by NB Power as a company—protecting low rates, reducing the carbon footprint and being responsible to the communities in which employees and customers work and live.

With this in mind, NB Power has renewed its focus on the three pillars of sustainability: the environment, society and the economy.

NB Power will continue to focus on identifying innovative environmental technologies that will benefit customers and further reduce its carbon footprint, by continuing to deliver electricity from a diverse mix of non-emitting resources such as wind, hydro, nuclear and other renewable resources and to ensure stable power rates and reliable supply.

This report is intended to provide a plan for NB Power to move towards sustainable electricity. The plan represents a snapshot into the future that reflects current conditions, assumptions and forecasts. The plan, however, will continually evolve as conditions change and as new sustainable opportunities emerge over time. It is intended that the plan be reviewed on a triennial basis to reflect the latest industry developments and information.

1.1. Background

In October 2011 a new energy policy was created called the *New Brunswick Energy Blueprint*[2] that provided a new direction and mandate for NB Power. In April 2012, NB Power completed a *30-year Strategic Plan*[3] that flowed directly from the *Energy Blueprint*. Using guidance from the *Energy Blueprint* as well as analysis from an interim Integrated Resource Plan (IRP), the *30-year Strategic Plan* identified three strategic priorities for NB Power:

1. Perform within the top 25 per cent ("top quartile") of utilities in North America;
2. Reduce debt by $1 billion and move towards an 80/20 debt to equity ratio by 2021; and
3. Pursue a new strategy of reducing and shifting in-province demand for electricity that will defer the need for new investments in generation and optimize the system to capture operating and fuel savings.

[2] http://www2.gnb.ca/content/dam/gnb/Departments/en/pdf/Publications/201110NBEnergyBlueprint.pdf
[3] http://www.nbpower.com/html/en/about/publications/2011-2040-strategic-plan-EN.pdf

The *Energy Blueprint* also changed the structure of NB Power through the creation of a new *Electricity Act*. The new *Electricity Act*, established in October 2013, amalgamated the NB Power group of companies into a single vertically integrated Crown utility. To increase transparency, NB Power will be subject to certain reporting and regulatory requirements under the *Electricity Act* that include filing every three years, with government and with the Energy and Utilities Board (EUB), an Integrated Resource Plan that outlines projected demand requirements and planned sources of supply.

NB Power is regulated by the EUB and directed by the *Electricity Act* to operate under the following policy objectives:

- To provide low and stable rates;
- To ensure a reliable system; and
- To meet the requirement of a *Renewable Portfolio Standard* (RPS).[4]

NB Power must submit an application before the EUB for any electricity sales rate changes. The EUB will consider the IRP as an input into their decision-making process when reviewing a rate application. Going forward, the EUB will also consider the IRP when reviewing NB Power's application for approval of any capital project above $50 million.

This IRP fulfils NB Power's renewed commitment to develop a long-term plan that considers economics, the environment, long-term societal interests, and various sensitivities of these features.

This IRP has been developed through a collaborative process with input from government departments and agencies, regulatory staff, municipal utilities as well as various customer stakeholders. A process was established to seek feedback from customers that provided guidance on the following questions:

1. How can NB Power help contribute to a successful New Brunswick?
2. How can NB Power help contribute to a sustainable environment for future generations?
3. What role could NB Power's long-term plans play in ensuring the development of new opportunities for energy innovation in New Brunswick?

[4] The RPS is not currently legislated but it is anticipated through guidance provided in the *New Brunswick Energy Blueprint*. The *Energy Blueprint* directs NB Power to have 40 per cent of in-province electricity sales provided by renewable resources by 2020.

This IRP analysis is part of a continual process that requires periodic load and resource updates as conditions change and evolve over time provincially, nationally and even globally. It reflects the evolution of NB Power's strategic planning approach as it embarks on a strategy to more closely align the IRP development activities to the business planning process. As technologies and circumstances change, so will the recommendations presented in the IRP. The IRP helps set NB Power's vision of the future.

1.2. The IRP Process

The planning process that encompasses the evaluation of supply and demand is called integrated resource planning. This IRP includes long-term strategies to ensure NB Power's obligation to supply in-province load is met, that renewable resource regulations are followed, and that resources comply with air emission standards. These long-term strategies provide long-term rate stability, reliability of supply, economic efficiency, environmental acceptability and financial viability.

The development of this IRP required in-depth analysis in three key areas:

1. Energy efficiency and demand considerations (also known as Reduce and Shift Demand - RASD) as well as supply considerations
2. Reliability and security of supply
3. Policy and regulatory considerations

Collaboration is an integral part of the IRP process. NB Power communicated and consulted with key stakeholders, including the Government of New Brunswick and customers, to ensure an optimum long-term supply of electricity for New Brunswick. The analysis was done to ensure an appropriate balance of the three key areas listed above while considering economic, environmental and societal implications.

Historically, the choices that were made to supply future electricity needs were based predominantly on the overall cost effectiveness of available options. These customarily encompassed a wide range of traditional generation technologies including hydro, nuclear, and fossil fuel generation such as coal, natural gas and oil. The cost effectiveness view continues to be prevalent today, but because of the uncertainty of the supply of imported hydrocarbon fuels and the volatility of corresponding fuel prices, combined with more stringent environmental requirements (including greenhouse gas (GHG) regulation and compliance with the renewable portfolio standard), a new focus of choosing environmentally preferred power generation will be required. The plan must be realistic and ensure that all supply-side options, including the environmentally preferred power generation choices, provide the appropriate level of reliability, and at reasonable costs.

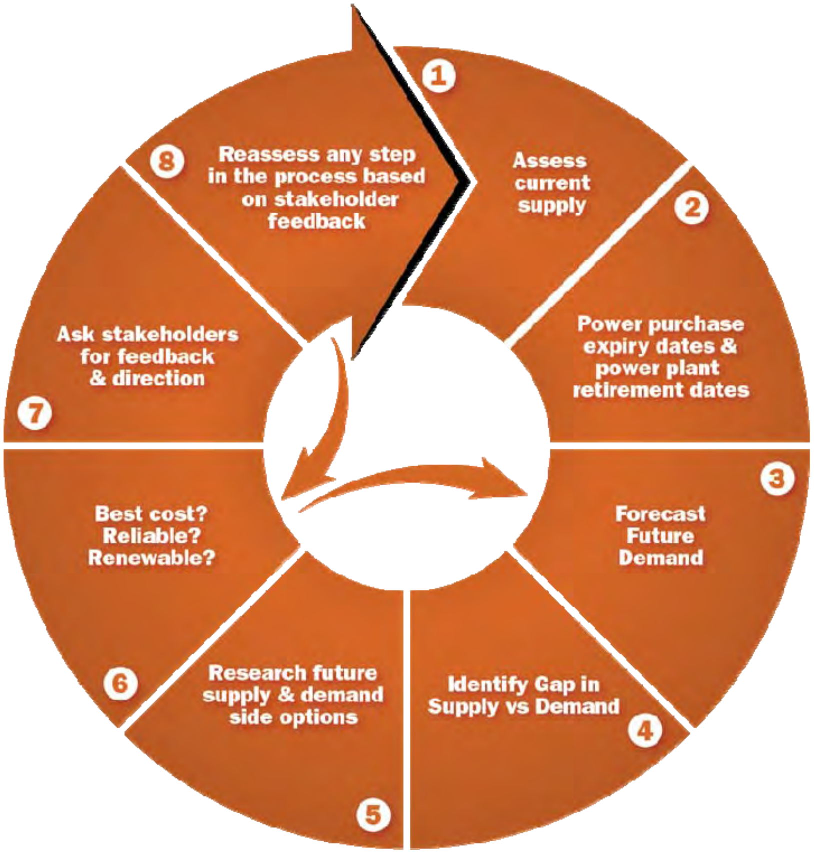
In addition to supply options, consideration was also given to energy efficiency and demand management programs that will help manage the load requirements for New Brunswick. These programs were developed in collaboration with Efficiency NB and in-province municipal utilities in order to deliver the appropriate level of cost-effective programs to New Brunswick consumers.

The IRP is NB Power's long-term plan that seeks to answer the following questions:

1. What is the current supply of electricity and what is the cost of delivering it using existing technology?
2. What impact does the current electricity supply have on the environment?
3. How do we ensure a reliable supply of power now and going forward?
4. How will changes in society and industry impact New Brunswick's future need for electricity?
5. What new technologies and techniques can NB Power use that will be the most cost-effective, reliable and sustainable?

To create the IRP, NB Power follows a well-defined process that is standard across utilities. The following diagram depicts the key elements of a step-by-step process used to answer the questions identified above.

Figure 1: IRP process



The IRP process can be broken down into a series of steps:

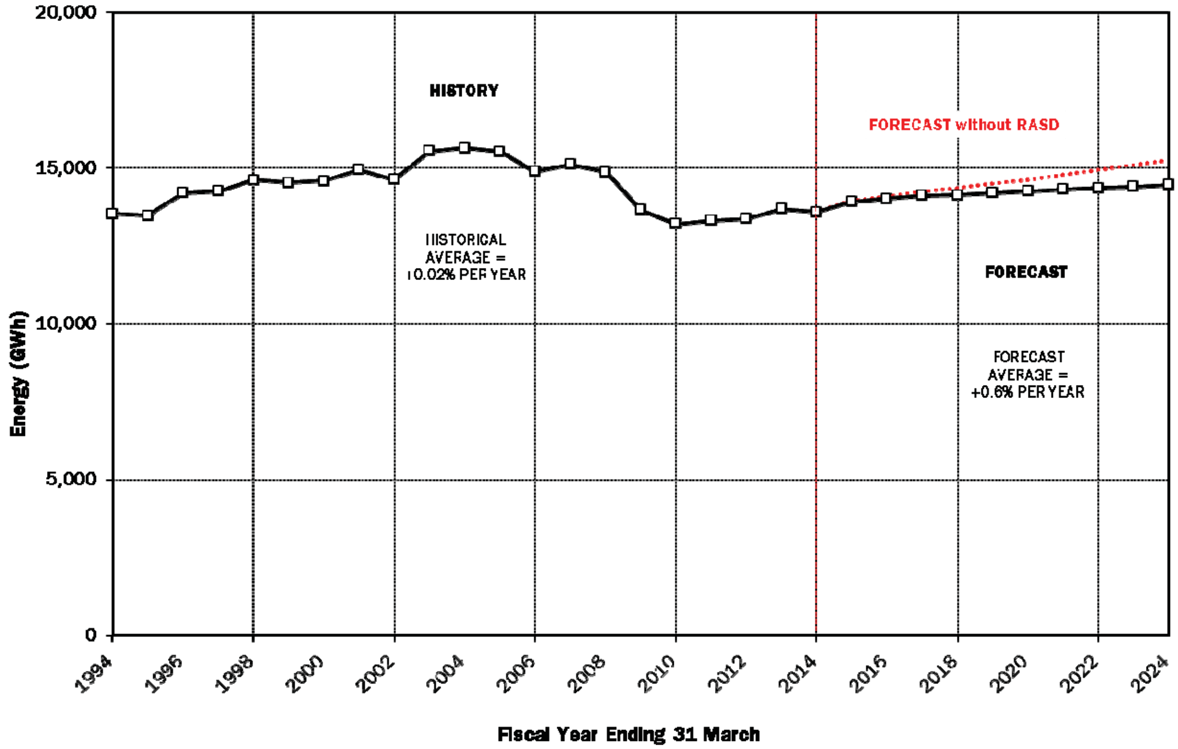
1. Look at the existing system and make certain assumptions about the corresponding parameters (such as fuel prices or polices/regulations going forward).
2. Look at the life expectancy of the existing power plants and expiry dates of the power purchase agreements.
3. Determine the long-term forecast of in-province electricity requirements.
4. Compare long-term supply with long-term requirements, to identify the gap.
5. Research all future supply and demand options and rank them according to cost.
6. Check that the least-cost options are reliable and that the renewable portfolio standard is met. If so, the viable supply and/or demand option feeds back to 3) and 4) to meet the gap.
7. Provide energy literacy and seek input from stakeholders through a public engagement process to determine appropriateness of all supply and demand options.
8. Give consideration to any option identified through public engagement by checking against the criterion in Step 6 and, if appropriate, then feed these back to 3) and 4) to fill the gap.

1.3. Basis of this IRP

The IRP assesses New Brunswick's future demand requirements based on population, customer expectations, electricity needs for households and businesses, and promoting economic growth in New Brunswick. The least-cost expansion plan responds to the in-province electricity needs including reserve requirements.

As New Brunswick's electricity needs have changed, particularly with changes in industry, so has NB Power's grid. The figure below shows how NB Power's electricity requirements decreased in the 2008/09 and 2009/2010 periods. NB Power subsequently responded by removing two generation assets at Grand Lake (in 2010) and Dalhousie (in 2012). It is expected that with the reduction in demand in the last several years, as well as new initiatives in NB Power's Reduce and Shift Demand (RASD) program, new resources to meet peak demand will not be required until well into the future.

Figure 2: Historic and forecast future electricity requirements for New Brunswick



Ultimately, NB Power is responsible for ensuring that adequate electricity is available to serve New Brunswick customers today and tomorrow. In addition to this long-term load requirement, this IRP also seeks to establish a development plan that responds to the *Electricity Act* and operates under the following policy objectives:

- To provide low and stable rates;
- To ensure a reliable power system; and
- To meet the requirements of a *Renewable Portfolio Standard* (RPS).

In the near-term, to contain costs, NB Power must optimize its existing assets and utilize its interconnections to buy and sell electricity.

In the medium-term there is a requirement to meet the renewable portfolio standard that directs NB Power to supply 40 per cent of the electricity it sells in New Brunswick from renewable resources such as biogas, biomass, solar, hydro, wind or renewable purchases by 2020. Creating a more efficient system will also play a role to achieve the RPS through NB Power's Reduce and Shift Demand (RASD) program.

Over the longer-term the capital stock turnover of existing resources must be recognized and the appropriate responses made for continued reliability of supply.

This IRP presents the least-cost expansion plan encompassing both supply and demand options to meet the forecasted NB Power in-province electricity requirements over a 25-year horizon. To meet this requirement, viable supply, energy efficiency and demand management options were analyzed extensively and incorporated into the plan with existing supply resources to determine the least-cost integrated expansion plan. This was done with consideration of environmental regulation and fuel price volatility. The resultant long-term plan was then measured against the vision of sustainable electricity supply, maintaining long-term rate stability and ensuring reliable electricity supply for New Brunswick.

The IRP results and recommendations presented in this document are based on various assumptions and forecasts that are subject to change. Flexibility of the least-cost expansion plan is essential and that the mix of options selected in this portfolio remain robust with changes in critical assumptions. This IRP has performed sensitivity analysis to measure the impact of the variation of individual critical parameters as well as the effects of the variation of several parameters occurring at the same time. This provided greater assurance that the long term expansion plan remained the least cost choice under the changed conditions.

2. EXECUTIVE SUMMARY

The following results of this IRP provide information regarding the strategic course of action that NB Power should consider to meet future resource needs. The integrated plan shown in Figure 3 indicates:

- Energy efficiency, demand management and demand reduction (also known as Reduce and Shift Demand – RASD) is vital to the IRP. This IRP has included an aggressive but cost-effective RASD schedule that assumes a savings of approximately 600 MW and 2 TWh by 2038. This electricity reduction potential provides a net savings of approximately $440 million to NB Power and to New Brunswick ratepayers over the study period.

- Consistent with the *Energy Blueprint,* to encourage development of locally owned small-scale renewable projects, 75 MW of cost-effective community energy resources are targeted by 2020 to help meet the 40 per cent RPS requirement.

- The current Mactaquac Generation Station's capacity and energy will no longer be available by 2030 because of the ongoing effects of Alkali-Aggregation Reaction (AAR). For the purpose of the IRP exercise, it was assumed that the capacity and energy is replaced, but with no assumption as to the replacement option or costs. Further study is underway to determine the optimum replacement supply and costs, and to fully assess the economics of all options for this replacement.

- Millbank and Ste. Rose life extension is the most economic choice for continued peak load requirements in response to their retirement in 2031.

- After the addition of new resources to meet the RPS and the Mactaquac Generating Station replacement option, as well as Millbank and Ste. Rose life extension, no new capacity is needed to meet peak demand until after 2040.

- GHG levels to meet in-province load remain below the 2005 historical level of approximately five million tonnes.

Figure 3: Integrated expansion plan

In Service Date	Integrated Plan	Scheduled Retirements
2014	RASD Program Starts Here	
2020	75 MW Community Energy	
2026		Grand Manan (-29 MW)
2027		Bayside PPA (-285 MW)
2030	Mactaquac Replacement	Grandview PPA (-90 MW) Mactaquac (-668 MW)
2031	Millbank /Ste. Rose Life Ext.	Millbank /Ste. Rose (-496 MW)
2032		Twin Rivers PPA (-39 MW)
2038		

In summary, the strategic direction recommended over the immediate term is:

- Initiation of community energy program to contribute to the RPS;
- Continuation of RASD programs with increased development in the long-term; and
- Continuation of technical work with regards to new generation options that might be viable in New Brunswick, especially options from renewable resources.

3. EXISTING SYSTEM

3.1. Load Forecast

The load forecast for the IRP is based on the NB Power Load Forecast 2014-2024 completed in the fall of 2013.

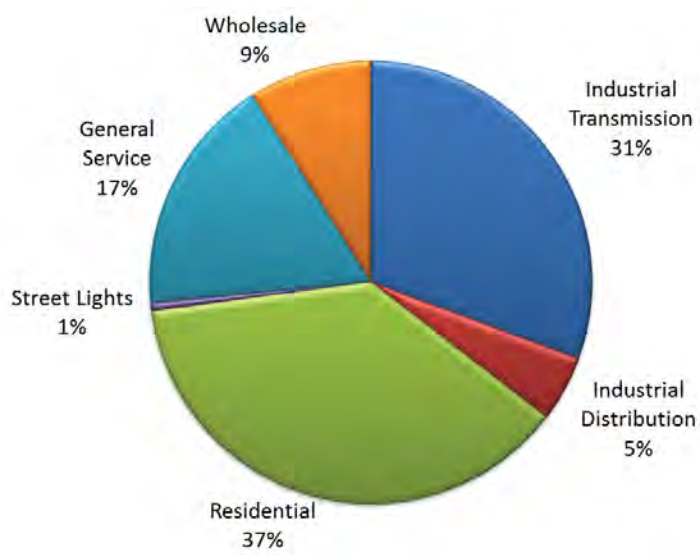
For forecasting purposes, electrical load is divided into three main groups: residential, general service and industrial. The grouping reflects similarity in end uses of electricity requirements within the group. Also, the customers within each group are to some extent homogenous. As a result, electricity requirements within each group are affected by similar factors.

The residential, general service and industrial forecasts are separated into six customer classifications:

1. residential
2. general service
3. street lighting
4. industrial distribution
5. industrial transmission
6. wholesale (includes the sales to the preceding five classifications by the municipal utilities in the cities of Saint John and Edmundston)

The relative proportions of NB Power's energy sales in fiscal year 2012/13 to each of the six customer classifications are shown in Figure 4.

Figure 4: NB Power energy sales in 2012/13



Residential
The residential classification is made up mostly of year-round domestic (household) customers. It also includes some non-domestic customers such as farms and churches, which account for less than 5 per cent of the total residential energy requirements. Also included in the residential classification are seasonal customers that account for approximately 1 per cent of the residential electricity requirements.

Figure 5: NB Power representative consulting with customer during new construction

Increases in the residential forecast are driven mainly by the addition of new customers and increasing annual household usage, somewhat offset by reductions associated with energy efficiency and price elasticity.

General Service
Sales to the general service classification include commercial (retail/wholesale, hotel/motel/restaurants, offices, etc.) and institutional customers (hospitals, schools, universities, etc.). As of March 2013, there were 25,400 general service customers served by NB Power, and an additional 5,006 served by the wholesale utilities.

Approximately 70 per cent of general service sales are commercial in nature and are therefore considered to be directly related to the level of provincial economic activity. The remaining 30 per cent of general service sales are to the institutional sector, which is indirectly related to the economic activity in the province.

Industrial
New Brunswick's industrial customers consume about 35 per cent of the total in-province electrical energy.

Industrial customers are divided into two groups:

1. Industrial transmission customers who are served at transmission voltages of 69 kV and above. There are 36 customers served at the transmission voltages. These customers constitute the majority of industrial sales.

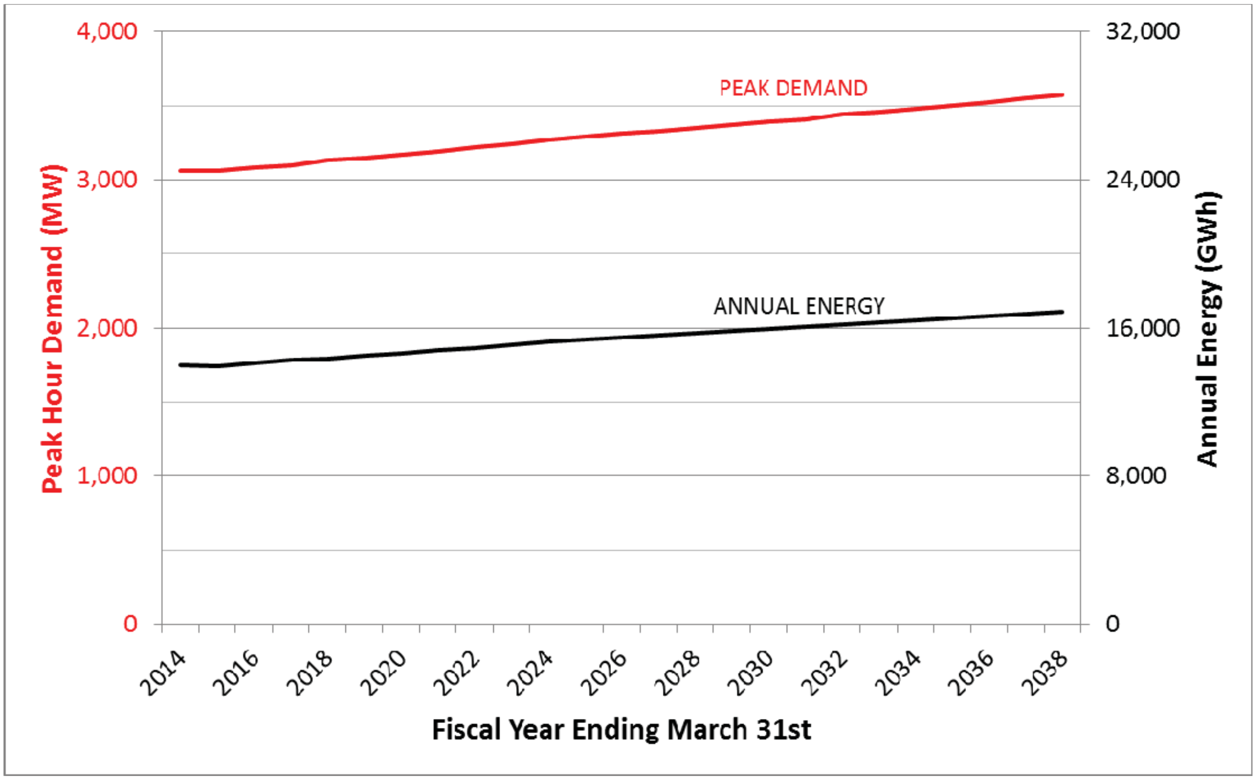
2. Industrial distribution customers who are served at distribution voltages less than 69 kV. NB Power serves approximately 1,800 industrial customers at distribution voltages, while the wholesale utilities serve approximately 70 others. Together, they account for approximately 15 per cent of the total industrial electrical energy requirements. The major industrial distribution groups are wood industries, food and beverage, manufacturing, and other operations.

Load Forecast Results
The total customer load is the combined total of the electricity sales to the six customer classifications, plus the transmission and distribution losses related to those sales.

In addition to the total annual energy, the maximum requirement in a 1-hour period is also critical for system planning. The maximum energy requirement in a 1-hour period is referred to as “peak hour demand.” NB Power is a winter-peaking system, driven by electric space heating in homes and businesses, with the peak demand normally occurring in January or February.

Using forecasts for each customer sector, the data is combined to establish the total in-province load forecast for the period 2014/15 to 2023/24. Beyond 2023/24, the forecast is escalated by class, using time-series regression models. The forecast includes estimates of energy efficiency measures that consumers are anticipated to naturally implement. Estimates of energy efficiency and demand reduction programs as part of the Reduce and Shift Demand (RASD) program have been removed from the forecast for the purpose of this IRP. This is done to establish the baseline by which the value of RASD can then be measured. RASD options will be evaluated and considered as part of the IRP process. The resulting forecast is shown in Figure 6.

Figure 6: Total in-province load forecast (energy and demand) excluding RASD programs



Note that the loss of load in New Brunswick since its peak in 2004, particularly in the forest products manufacturing industry, leaves the current in-province load at the same level that the utility served in 1995.

The average growth rate for peak demand is 0.7 per cent per year while the average growth rate for energy is 0.8 per cent per year. These growth rates are before the impact of RASD programs.

3.2. Generation Resources

NB Power has a diverse portfolio of generation resources and power purchase agreements (PPA) from a blend of hydro, nuclear, coal, natural gas, oil-fired thermal and combustion turbines, biomass and wind, as shown in the system map below.

Figure 7: System map

At this time, no new generation has been committed for construction. The current generation capacity and PPA portfolio, as well as other statistics of the NB Power system, is shown in Figure 8.

Figure 8: NB Power Net Generating Capacity[5,6] and other statistics[7]

Generating Capacity Thermal	
Coleson Cove	972 MW
Belledune	467 MW
Total Thermal	1,439 MW

Generating Capacity Hydro	
Mactaquac	668 MW
Beechwood	112 MW
Grand Falls	66 MW
Tobique	20 MW
Nepisiguit Falls	11 MW
Sisson	9 MW
Milltown	3 MW
Total - Hydro	889 MW

Generating Capacity Nuclear	
Point Lepreau	660 MW

Generating Capacity Combustion Turbine	
Millbank	397 MW
Ste.-Rose	99 MW
Grand Manan	29 MW
Total - Combustion Turbine	525 MW

Total Generating Capacity	
Thermal	1,439 MW
Hydro	889 MW
Nuclear	660 MW
Cumbustion Turbine	525 MW
Total Generating Capacity	3,513 MW

Power Purchase Agreement (PPA)	
Wind	294 MW

Other Power Purchase Agreement (PPA)	
Bay Side (Natural Gas)	285 MW
Grand View (Natural Gas)	90 MW
Twin Rivers (Biomass)	39 MW
St George (Hydro)	15 MW
Edmunston Hydro	7 MW
Other Renewable	1 MW
Total	437 MW

Number of Lines	
Distribution Lines	20,815 km
Transmission Lines	6,849 km

Exporting and Importing Capacity	
Export Capicity	2,270 MW
Import Capicity	1,775 MW

Number of Customers	
# of Direct Customers	348,791
# of Indirect Customers	45,794
Total Customers	394,585

This diverse mix of generation capability is expected to meet the electricity requirements of New Brunswick well into the future. In addition, NB Power is interconnected with neighbouring utilities for the purpose of importing and exporting electricity, and for increased system reliability. NB Power's electricity exports have contributed to lower rates for New Brunswick customers. The potential for interconnection imports have allowed NB Power to reduce costs by displacing higher-cost generation that would have been required to meet in-province electricity requirements.

Each PPA commitment has a term as defined in the applicable contract. Generally, these are fixed dates. The end-of-life dates for NB Power-owned generating stations are less certain. For accounting purposes, they have a life assigned that is based on typical experience for that type

[5] 30 MW from the Point Lepreau Generating Station is committed to Maritime Electric Company Limited (MECL) for the life of the unit. Total capability is 660 MW, which leaves 630 MW for in-province needs.
[6] The contribution to capacity for wind generation is calculated as 30 per cent of the installed capacity (i.e., 294 MW installed wind capacity * 0.3 = 88.2 MW). This is due to the intermittency of this resource.
[7] NB Power 2012-13 Annual Report: http://www.nbpower.com/html/en/about/publications/annual/2013_Annual_Report_EN.pdf

of facility. In actual practice, retirements are dependent on an economic evaluation for each unit as it approaches the end of its useful life. For purposes of this IRP, retirement schedules are initially based on the corresponding accounting life, with consideration of a reasonable extension period that could allow the facility to continue to operate without significant capital expenditure. Consideration of life extension potential was made through studies conducted by NB Power plant engineering experts and through economic analysis. The generating stations and PPA's with an end of life occurring within the study period horizon of the IRP are as follows:

Figure 9: Retirement schedule

Description	Fuel type	Capacity (MW)	End of life date
Grand Manan	Diesel	29	2026
Bayside PPA	Natural Gas	285	2027
Grandview PPA	Natural gas	90	2030
Mactaquac	Hydro	668	2030
Millbank	Diesel	397	2031
Ste. Rose	Diesel	99	2031
Twin Rivers PPA	Biomass	39	2032

Further detail is provided in Appendix 1 – List of Assumptions for IRP

3.3. Transmission and Interconnections

The NB Power transmission system is the intermediate part of the power system between the sources of power supply and load centres. The NB Power transmission system has been strategically designed to provide reliable electricity to in-province customers while also providing opportunities to buy and sell electricity with neighbouring jurisdictions.

The NB Power transmission system includes all of the 345 kV, 230 kV, 138 kV and 69 kV transmission lines (6,849 kilometres in total), termination equipment and control equipment to permit the necessary operation of the interconnected transmission network. This system provides the means for delivery of electricity to meet forecast demand requirements under normal operating conditions.

New transmission requirements are driven by a number of factors including: the need to connect new generation, in-province load growth, maintaining or increasing imports and exports, improvements in system reliability and meeting industry Reliability Standards.

The existing transmission system has evolved over the past century. It began mainly as 69 kV lines connecting small generating stations in municipal distribution systems in the first half of the 20th century. Following the Second World War, and to keep up with the load growth through the 1960s, the 138 kV system was expanded to form a figure-eight network around the province and to interconnect with Nova Scotia for the first time. Expansion continued in the early 1970s with the completion of a 230 kV system connecting from the northeast (Dalhousie–Bathurst–Newcastle) area to Keswick in the west, and across the province to Salisbury in the southeast. The maximum system voltage increased to 345 kV with the completion of the New England interconnection and the Coleson Cove Generating Station in the late 1970s. Through the 1980s and 1990s, the 345 kV system expanded to encircle the province and extend into Nova Scotia.

Figure 10: NB Power 345 kV transmission tower

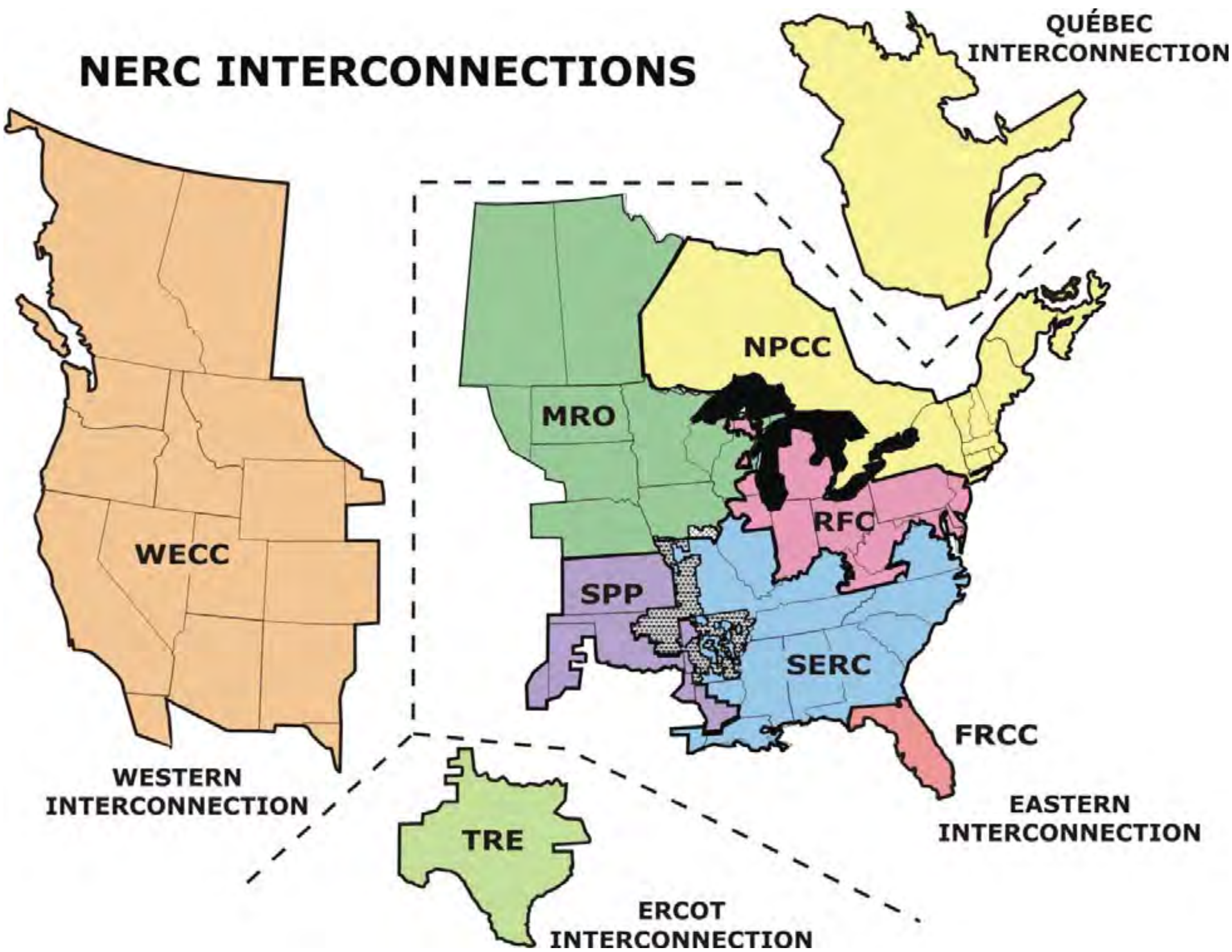
NB Power continuously assesses the transmission system to ensure it meets all Reliability Standards and provides benefits to New Brunswickers. Even though the downturn in the economy in 2008 and 2009 resulted in approximately 10 per cent load loss in New Brunswick, which resulted in less stress on parts of the transmission system, other changes on the system since then have put stress on other areas of the system. These changes include the retirement of the Dalhousie Generating Station (300 MW), the retirement of the Grand Lake Generating Station (57 MW), the addition of large wind facilities in the Maritimes (approximately 800 MW) and the almost continuous large imports from Hydro Quebec. The net effect to the transmission system, and to the power system as a whole, is that it is more stressed today than was the case almost a decade ago. This is particularly prevalent in the southeast corner of the province as reflected through the lowering of our transfer capabilities to PEI and Nova Scotia. Additional transmission reinforcements, or additional generation, are required in this area to return our transfer capabilities to historical values.

Sufficient transmission capacity is available for in-province load levels and for exports, assuming necessary generation is available in critical areas and during certain times of the year, and that special protection systems are in place in the event of loss of transmission and/or generation equipment.

The transmission system was designed to deliver the existing generation economically to all in-province customers, and to export surplus supply to neighbouring utilities. The ability to import electricity from Quebec, New England, and at times from Nova Scotia, has also been very important to NB Power's ability to lower its costs for the delivery of electricity to its customers. The next 20 years and beyond could see changes to the generation supply types and locations both within and outside New Brunswick. These potential changes in generation supply may require new transmission infrastructure to reliably and economically interconnect them with the NB Power system.

The NB Power transmission system is a small part of a much larger bulk transmission system in the Eastern Interconnection (see Figure 11). NB Power belongs to the Northeast Power Coordinating Council Inc. (NPCC). The NPCC mission is to promote and enhance the reliable and efficient operation of the international interconnected bulk power system. The geographic area covered by NPCC includes New York, the six New England states, Ontario, Québec and the Maritime provinces.

Figure 11: North American regional reliability councils and interconnections



Interconnected transmission lines can be used to transfer electricity from one jurisdiction to another under contractual arrangements, or on a spot market basis and during emergencies. NB Power has always placed major emphasis on developing strong interconnections with neighbouring systems for both economic and reliability reasons.

Out-of-province electricity purchases and/or sales are made under short-term (daily and weekly) contracts or on a spot basis. Actual interconnection capabilities with neighbouring jurisdictions are dependent on system conditions in New Brunswick and other regions at the time of transfer. In the past, the interconnection with New England has enabled NB Power to construct larger, more economical generating units to allow for the purchase and sale of surplus electricity on both a short- and long-term basis. NB is also interconnected with Quebec, Nova Scotia and Prince Edward Island (PEI). The interconnections support the system with direct and indirect contributions to capacity reserves, thus reducing the requirement for additional capacity to serve in-province customers. The following chart shows the capabilities of NB Power's major interconnections.

Figure 12: NB Power's transmission import/export capabilities (MW)

Depending on the in-province load and/or the generation dispatch, as well as the condition of the in-province transmission system, these limits cannot always be achieved. The limits can also vary depending on conditions within the interconnected jurisdiction.

Transfer Capability between New Brunswick and Nova Scotia and PEI

The New Brunswick to Nova Scotia and PEI transfer capabilities are a function of the transmission system's transfer capability into the southeastern region of New Brunswick, minus the southeastern region load (mainly Moncton, Dieppe, Riverview and surrounding areas). As the New Brunswick southeastern region load increases, the net electricity transfer capability available to PEI and Nova Scotia is reduced. NB Power's in-province load growth in the Moncton area in the past 10 years has reduced the combined transfer limits to PEI and Nova Scotia.

Transfer Capability between New Brunswick and Quebec

The NB Power to Hydro Quebec (HQ) transfer capability is the sum of the two high voltage direct current (HVDC) stations, one at Eel River (owned and operated by NB Power) and the second at Madawaska (owned and operated by HQ). The Eel River HVDC Station, shown in Figure 13, has an import/export capability of 350 MW. The total import/export transfer capabilities with HQ are as follows:

- For import from HQ:

Eel River HVDC	350 MW
Madawaska HVDC	420 MW
Radial Ties at Eel River and Madawaska[8]	230 MW

- For export to HQ:

Eel River HVDC	350 MW
Madawaska HVDC	420 MW

[8] Radial ties with HQ are interconnections that can serve a portion of New Brunswick load in isolation of the main NB Power grid.

Figure 13: NB Power's Eel River HVDC Station

Additional HVDC interconnections with HQ are a possibility in the future and will be considered with other regional transmission expansion and refurbishment options. The Eel River HVDC station is currently undergoing a life extension project with planned completion by the end of 2014 in order to maintain its 350 MW transfer capability. The Madawaska HVDC station is planned for life extension within the next five years.

Transfer Capability between New Brunswick and New England

The maximum transfer capability from New Brunswick to New England is 1,000 MW. This is the maximum reliable transfer capability assuming all transmission facilities in Maine and New Brunswick are in service. In December 2007, a second 345 kV interconnection was put into service. This development strengthened the New England–New Brunswick interface since the additional interconnection increased transfer from 700 to 1,000 MW, and improved the reliability and reduced the likelihood of separation of the Maritimes from the interconnected New England power system.

In addition to the major interconnections into New England, NB Power can serve isolated loads located in Maine. These interconnections are smaller and serve loads in Northern Maine (approximately 130 MW) and Eastern Maine (approximately 25 MW non-firm).

New Brunswick Transmission Requirements

Although the current transmission system in New Brunswick is sufficient to reliably transfer electricity of the existing generation, potential upgrades may be necessary in the future, especially in the southeast of the province as load in the Moncton area grows. Also, the addition of more wind generation in New Brunswick will likely require new transmission to be built. The wind farms currently in service in New Brunswick required minimal transmission infrastructure due to the farms' close proximity to existing terminals and transmission lines. If wind and other intermittent generation are added to the system, the integration of these resources can become more complex due to the balancing of generation, voltage and other power quality issues.

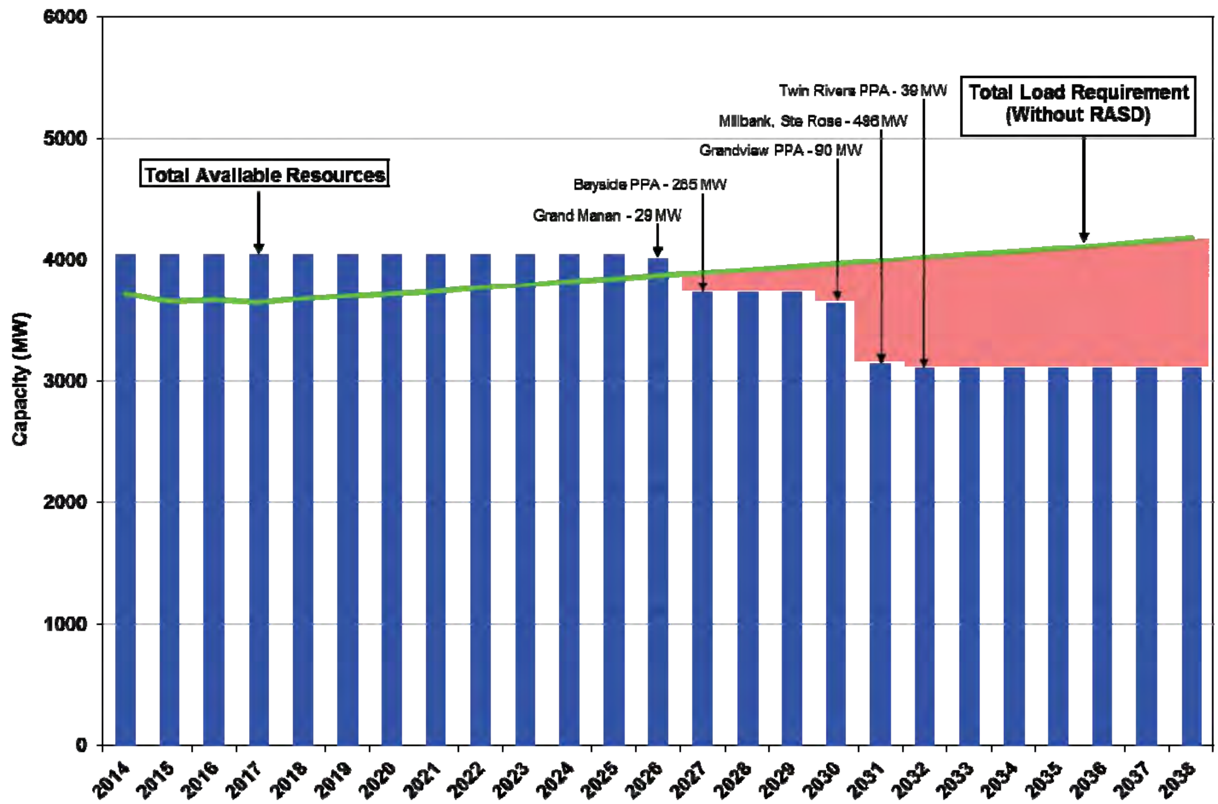
NB Power continues to investigate solutions to future transmission constraints. Obvious solutions include both adding additional transmission as well as strategically locating generation closer to the requirement. Another solution exists that could preserve and extend the existing transmission system. This solution includes targeted demand reduction programs through smart grid technology. This is part of the NB Power Reduce and Shift Demand (RASD) and smart grid initiative. This program is intended not only to defer the need for new generation in the future, but also to potentially defer or reduce the need for new transmission infrastructure. More information on RASD is provided in the sections that follow. The final solution to transmission constraints will be evaluated in a separate study. The results of this IRP will be used to establish the baseline of this study.

3.4. Load and Resource Balance

Like other plants in North America, NB Power's fossil generating stations have normal life spans of approximately 45 years. This provides utility planners with a guide for making decisions on the timing and introduction of possible new generation. The final decision on whether a station will be refurbished or replaced cannot be made definitive until near the scheduled retirement of that station. Conditions (specific to both generation plant and external) will change over time, and this will require reassessment and adjustment of the plan. Assuming the future continuation of both the obligation as a regulated utility to provide reliable service to its customer base, as well as other known conditions such as environmental regulations and renewable standards, NB Power can provide a snapshot of the electricity requirement and assess what options may be available to meet that requirement.

The chart shown in Figure 14 provides a snapshot of the electricity need for NB Power, assuming the generation resources are as described in Section 3.2 (Generation Resources) and depicted by the blue bars in the chart. This is then compared to the current load requirement and growth, including reserve requirements[9] as depicted by the green line.

Figure 14: Total load requirements and generation resources 2014-2038



[9] NB Power's electricity requirement includes customer demand plus losses plus reserve capacity. NB Power must provide 20 per cent of its firm load or its largest unit (whichever is larger) in reserve for emergencies.

In this load and resource assessment, energy efficiency and demand-side management estimates associated with NB Power's Reduce and Shift Demand (RASD) program have been removed from the load forecast. These estimates have been assumed in the official load forecast with the exception of naturally occurring demand-side management. The load and resource assessment provides the basis for the IRP assessment in which new cost-effective energy efficiency and demand-side management options will be considered. It provides the starting point for consideration of new generation supply as well as reaffirms the value of integrating demand management programs associated with NB Power's RASD program.

From this assessment, the need for capacity will outstrip the resources starting in the 2027 time frame. And by the end of the period in 2038, NB Power's requirements will outstrip supply by about 1,100 MW. Beyond 2038, NB Power's major generating stations at Point Lepreau, Belledune and Coleson Cove will also reach the end of their lives and be scheduled for retirement. When this occurs, NB Power's existing fossil fleet including power purchase agreements (PPA's), representing a total of approximately 3,000 MW of capacity or about two-thirds of NB Power's overall capacity, will be retired. The resources that remain in the very long-term will be hydro generating stations, which on average have 100-year life spans.

It has been assumed in this IRP that all of the hydro assets will be replaced by an equivalent quantity of capacity and renewable energy, with the first replacement being the Mactaquac hydro station. This facility is expected to reach the end of its life by 2030, based on a projection that the powerhouse and spillway will no longer be useful because of problems with the concrete related to alkali-aggregate reaction (AAR). This condition is affecting the concrete portions of the station only, causing problems with expansion. The earthen dam is not impacted by AAR.

NB Power has identified three possible options for the station: rebuilding the station with a new powerhouse and spillway; maintaining the earthen dam and spillway only; or restoring the river to its natural state.

Given the anticipated times required for approvals, design and site work, NB Power needs to choose a preferred option for the facility by 2016. That preferred option will then be subject to the appropriate approval processes of the provincial and federal governments and the province's Energy and Utilities Board.

Between now and 2016, NB Power will complete an evaluation of the three options, seeking information and advice from subject matter experts, First Nations, people who live and work near the facility, and any other stakeholders who might be affected by the decision. The evaluation will consider economic, environmental and social factors.

While the load and resource assessment shows a shortfall beginning in 2027, it also identifies a surplus of capacity during the transition period from 2014 to 2026. At its peak, the surplus reaches about 400 MW in 2014 and is slowly reduced as load grows on the system. During this transition period from 2014 to 2026, the contribution of assets to the system will need to be evaluated and opportunities examined to find markets for the surplus generation other than in-province load.

The generating plant that appears to present the greatest opportunity for obtaining savings during the transition period is the Coleson Cove Generating Station, which runs on heavy fuel oil. While this facility is designed as a base load station, its forecast hours of operation are extremely limited. Its limited operation is a result of a fuel oil cost that makes this plant uncompetitive with other fuels, including purchases in the long term. Detailed modelling of long-term operation suggests annual capacity factors of less than 5 per cent would be expected at the Coleson Cove station operating on fuel oil. This is in contrast to the coal-fired Belledune Generating Station and Point Lepreau Generating Station, which will continue to operate at high capacity factors in this forecast, due to their lower fuel costs.

The Coleson Cove Generating Station has a net output capacity of 972 MW, supplied by three equally sized generators. The plant was refurbished in 2004. Subsequent to that, Unit #3 was modified to co-fire petroleum coke with heavy fuel oil at up to 20 metric tons per hour. At light loads, this represents in excess of 50 per cent of the fuel requirement for that unit. When Coleson Cove is called upon to supply electricity, it will typically be Unit #3 that is dispatched. Because of Coleson Cove's size and the need for this capacity in the winter months, this facility is an important asset to meeting in-province needs. The opportunity exists to convert two units to natural gas. Factors that will influence the final decision are the capital costs of the conversion, the projected capacity factor, natural gas infrastructure costs, the need to contract for firm natural gas and pricing for natural gas in the long term. NB Power continues to evaluate this opportunity. This IRP study has assumed Coleson Cove continues to operate on heavy fuel oil for the life of the facility. Because of the anticipated low operating hours, the condition of the facility will be such that it becomes a very good candidate for life extension at reasonable cost. This study, therefore, has also assumed that this facility is made available for an additional 10 years beyond its normal operating life, with the appropriate costs included for life extension.

The Belledune Generating Station is the only coal-fired facility on the NB Power system. As mentioned, this facility operates at a high capacity factor because of its low cost fuel. The operation of this facility and its greenhouse gas (GHG) emission intensity are now regulated under the *Canadian Environmental Protection Act*.[10] This new regulation sets a stringent performance standard for new coal-fired electricity generation units and those that have reached the end of their useful life, which is defined as 50 years in the regulation. In this study, Belledune is assumed to be retired in 2044.

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[10] https://www.ec.gc.ca/cc/default.asp?lang=En&n=C94FABDA-1

As mentioned, no new generation is required in the transition period 2014 to 2026. However, during the transition period, projects considered will include the addition of generation to meet the RPS. To date, wind generation has been the choice to meet this requirement. Going forward, biomass opportunities, small hydro or photovoltaic may be developed. Section 4.1.4 (Hydro) outlines two projects, Grand Falls and High Narrows, which may prove to be economic options during the transition period that will have an impact well beyond the transition period. The development of cost-effective renewable, locally owned community energy projects may contain a combination of renewable options that can also help meet the RPS requirement.

3.5. Environmental and Sustainability Considerations

NB Power has diversity of supply within its existing fleet of generating assets. This diversity minimizes risks attributed to changing regulations, and helps with security of supply and sustainability for the long term.

Sustainable electricity, as defined by the Canadian Electricity Association, has three basic pillars: environment, social and economic. As set out in its new corporate vision of "Sustainable Electricity," NB Power is moving towards a more sustainable source of energy supply for the future, one that focuses on these three pillars.

Each of the three pillars of sustainable energy includes specific principles.

1. Environment
    a. Environmental Impact
    b. Stewardship and Biodiversity
    c. Climate Change
2. Social
    a. First Nations Relations
    b. Communication and Engagement
    c. Health and Safety
    d. Workplace
3. Economic
    a. Economic Value
    b. Energy Efficiency
    c. Security of Supply

3.5.1. Sustainability Pillar - Environment

There are several environmental considerations for NB Power's existing system that have to be factored into the IRP in the environmental pillar of sustainability. Aside from reducing the environmental impact of any new project and adopting a philosophy of strong stewardship and biodiversity, NB Power must take into account pending changes to environmental regulation. These include

- further GHG regulations (Carbon Dioxide - CO_2) beyond existing coal regulations,
- pending air pollutant regulations (Sulphur Dioxide – SO_2, Nitrogen Oxide – NO_x, Total Particulate Matter – TPM and Mercury – Hg),
- pending changes to the *Fisheries Act, and*
- possible changes to the *Species At Risk Act (SARA).*

Further GHG Regulations
In addition to the current coal regulations, further GHG regulations could be applied to other fuels such as oil and natural gas. This could have an impact on current thermal (GHG emitting) assets including the Coleson Cove Generating Station, as well as on natural gas-fuelled power purchase agreements. On January 29, 2010, Canada inscribed in the Copenhagen Accord its 2020 economy-wide target of a 17 per cent reduction in greenhouse gases from 2005 levels. This target is completely aligned with the US target.[11]

To estimate the impact of GHG regulations in the planning of the IRP, NB Power has included a sensitivity that would include some form of carbon pricing through either a carbon trading scheme or through carbon taxes that could be used to capture the potential impact on the environment. Included in this sensitivity would be an assumption of the potential cost on the environment from the full carbon cycle of extraction and delivery of various fuels, to the utilization of these fuels to produce electricity.

In the absence of a study of the full lifecycle assessment of carbon for the production of electricity for NB Power, a carbon price was assumed as follows below.

Carbon Prices
Estimating carbon prices to integrate into the IRP proved to be an academic exercise due to the absence of existing and mature regulated carbon markets. As is indicated in Figure 15, there are several markets currently in existence. The Regional Greenhouse Gas Initiative (RGGI) operating in the Northeast U.S. started trading in January 2009 and in its initial stages has seen an over-supply of permits in the market, resulting in a low carbon trading price.[12] The Alberta market[13]

[11] http://apps1.eere.energy.gov/news/news_detail.cfm/news_id=15650
[12] RGGI – Regional Greenhouse Gas Initiative. http://www.rggi.org/, Clearing price – March, 2014

was established in 2007, but has an unlimited technology fund set at $15/tonne. Essentially, this acts as a price ceiling, resulting in a maximum potential carbon price of $15/tonne. The Western Climate Initiative (WCI[14]) was started in early 2007 by the governors of five western states (Arizona, California, New Mexico, Oregon and Washington) with the goal of developing a multi-sector, market-based program to reduce greenhouse gas emissions. By mid-2008, the initiative had expanded to include two more states (Montana and Utah) and four Canadian provinces (British Columbia, Manitoba, Ontario and Quebec). The most recent auctions held in California and Quebec quote carbon prices in the $11US/tonne range. The most mature of all markets is the European Union Emissions Trading Scheme (ETS[15]), which started trading in 2005. It currently trades at ~$7CDN/tonne but traded at a high of ~$45CDN/tonne in the summer of 2008.

Multiple studies have been published predicting the price of carbon. When the federal government released the *Turning the Corner*[16] in March 2008, it modelled the price of carbon to be at $15/tonne in 2010, 2011 and 2012, $20/tonne in 2013, then escalating at gross domestic product (GDP) until 2020 when the price would have full market exposure and is predicted to be $65/tonne. The National Round Table on the Environment and the Economy (NRTEE) published a report predicting that the price of carbon would need to be $100/tonne by 2020 if the government's targets were to be achieved.[17] The U.S. Environmental Protection Agency (EPA[18]), based on the Waxman-Markey Bill and the *American Clean Energy and Security Act*, estimated a carbon price of $20CDN/tonne in 2010 escalating to $25CDN/tonne by 2020.

Figure 15: Predicted price of greenhouse gas (or carbon) credits

Market/Study	Current Price	2010 Estimate	2020 Estimate
RGGI	$4/tonne		
Alberta	$15/tonne		
EU ETS	~$7/tonne		
WCI	~$11/tonne		
Turning the Corner		$15/tonne	$65/tonne
NRTEE		$15/tonne	$100/tonne
US EPA		$20/tonne	$25/tonne

The variability in existing markets and current studies is significant. In Section 8.4 (Sensitivity Analysis) contained in this IRP, two sensitivities were analyzed that included carbon prices of

[13] http://environment.alberta.ca/

[14] WCI – Western Climate Initiative. http://www.wci-inc.org/

[15] EU ETS – European Union Emissions Trading Scheme. http://ec.europa.eu/clima/policies/ets/index_en.htm

[16] http://www.propanefacts.ca/upload/reports/RegulatoryFramework_GGM_March08.pdf

[17] NRTEE – National Roundtable on Environment and the Economy – "Achieving 2050: A Carbon Pricing Policy for Canada". Released April 2009.

[18] U.S. EPA – United States Environmental Protection Agency.

$50 and $100 per tonne. These cases were compared to the base case, which has assumed no carbon pricing.

Pending Air Pollutant Regulations

The two major thermal plants in NB Power's fleet, the Belledune and Coleson Cove generating stations, are equipped with environmental control equipment. Since the equipment was installed, starting in the early 1990s, emissions of SO_2, NO_x and Total Particulate Matter (TPM) have been significantly reduced. The releases of SO_2, NO_x and TPM are relatively low when compared to similar plants in other jurisdictions. New regulations could have an impact on NB Power's thermal assets and some further reductions may be required. NB Power is actively participating in this process with Environment Canada.

The *Fisheries Act* and the *Species at Risk Act (SARA)*

The federal government is contemplating the introduction of a new Fisheries Act to replace the current *Fisheries Act*. Any changes to the *Fisheries Act* could have an impact on current and future hydro facilities with respect to fish passages. Changes could also result in current and future thermal generating stations needing further cooling water as an operational requirement to avoid fish kill.

SARA is currently undergoing a five-year review. The Canadian electricity sector has submitted suggested changes to the act to reduce risks to current assets. As it stands, there are no provisions to protect utility assets when a new species is identified as a species at risk. Therefore, capital investments made in the past with consideration for the laws and regulations of the time (often pre-dating the introduction of *SARA*) could be forced to shut down if they are deemed to be counter to *SARA,* as a new species is introduced to the list. The electricity sector is working to amend *SARA* to include provisions for such situations. If it does not succeed, the risk will remain.

3.5.2. Sustainability Pillar - Social

There are four principles in the social pillar of sustainability, related to

- First Nations relations,
- communication and engagement,
- health and safety, and
- workplace.

Figure 16: Elder George Paul and NB Power employees participate in a cultural awareness and sensitivity workshop

NB Power has recognized the need for renewed focus in First Nations relations, and communications and engagement with customers. These areas have been targeted for improvement as NB Power strives to become top quartile.

NB Power is committed to being one of the select utilities in North America, especially in safety. In November 2013, executive members of NB Power and IBEW Local 37 committed to the re-establishment of NB Power as one of the safest utilities in North America. By signing a renewed commitment, NB Power and the IBEW Local 37 will work together to keep safety as a top priority. NB Power has been recognized for workplace achievements and has been named one of Canada's Top 100 employers by Mediacorp Canada Inc. It has also been awarded the Healthy Workplace Award by the National Quality Institute.

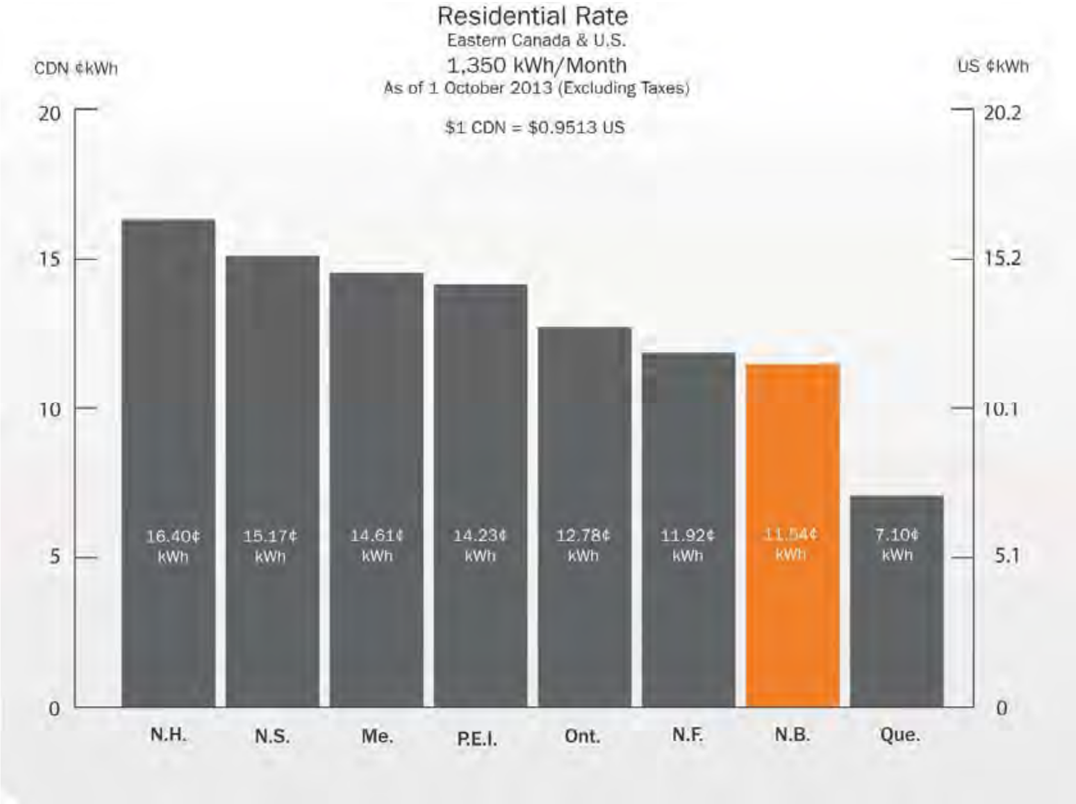
3.5.3. Sustainability Pillar - Economic

There are three principles in the economic pillar of sustainability:

- economic value;
- energy efficiency; and
- security of supply.

Important principles to NB Power are providing for economic value and security of supply. Electricity rates in New Brunswick have been identified as some of the lowest in the region (lower than Maritime Electric in PEI (MECL), Central Maine Power (CMP), Public Service New Hampshire (PSNH), Hydro One (Ontario), and Newfoundland Power). Only Hydro Quebec has lower residential rates.

Figure 17 – Residential electricity rates in the region[19]



With respect to security of supply, NB Power boasts a diverse energy supply that includes hydro, wind, nuclear, biomass and fossil fuel-based generation. This diversity minimizes the risk exposure of any one type of generating resource, and increases the security of supply for NB Power customers.

In the past, NB Power has achieved varying degrees of success in the area of energy efficiency and demand management. NB Power now has a renewed focus on efficiency and demand management through its Reduce and Shift Demand (RASD) program. This program involves demand reduction through energy efficiency programs, and demand shifting through the installation of smart grid infrastructure and a multi-year partnership with Siemens. Further detail on the RASD program can be found in Section 6 (Energy Efficiency and Demand Management).

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[19] The foreign exchange rate indicated in this chart was current at the time of the publication of the chart, and may not be consistent with the exchange rates used in this study.

3.6. NB Renewable Portfolio Standard

NB Power has one of the most diversified generation fleet of facilities in North America. Decisions to develop hydro and biomass resources, made decades ago, and the more recent development of wind resources, have enabled New Brunswick to become a North American leader in diverse renewable energy generation. NB Power currently supplies about 30 per cent of its in-province electricity requirements from indigenous sources such as wind, biomass and hydro resources.

The Government of New Brunswick has committed to increasing the development of further renewable energy by creating a new Renewable Portfolio Standard (RPS). This new standard will be part of the *Electricity Act* that will require NB Power to ensure that by 2020, 40 per cent of its in-province electricity sales are provided from renewable energy. Renewable energy imports, including large-scale hydro from Quebec or Newfoundland and Labrador, will also be eligible to meet the new Renewable Portfolio Standard. This will allow NB Power increased flexibility to meet its obligations under this new standard at the lowest possible cost, which will ensure alignment with its overarching strategy of reducing debt.

Since the goal of the RPS is to reduce the use of fossil fuel generation, that objective can be met by reducing energy usage or by building renewable generation. In most cases, energy efficiency is a less expensive option than building new renewable generation. As a result, NB Power will be aggressively pursuing demand management programs to assist in meeting the RPS target.

In the interest of continuing to improve New Brunswick's environmental performance, energy efficiency is an essential element. By shifting and reducing electricity demand through its RASD program, NB Power will be able to reduce the need for generation from fossil-fuelled plants, thereby increasing the proportion of renewable energy on its system. Innovative programs that result in significant energy reduction will enable NB Power to achieve the 40 per cent RPS in the most cost-effective and efficient manner.

In addition to RASD helping to achieve the RPS goal of 40 per cent by 2020, additional renewable resources have also been built into the IRP plan. NB Power has assumed that development of energy resources from local small-scale projects would occur as part of government's energy action plan, *The New Brunswick Energy Blueprint*. This action plan provides direction that will:

1. support local community and First Nations small-scale renewable projects;
2. integrate current and future wind generation in the most cost-effective and efficient manner; and
3. support promising solar, bio-energy and other emerging renewable energy technologies.

This IRP has assumed a phased-in approach to this development so that by 2020, 75 MW of incremental renewable capacity will be added to the system. To manage the integration of this development with the system, NB Power will focus on projects that provide dispatch flexibility and that can integrate with NB Power's smart grid initiative. This initiative is explained in greater detail in Appendix 12.

Although not part of the renewable portfolio standard, non-emitting resources such as the Point Lepreau Nuclear Generating Station contribute significantly to reducing the use of fossil fuels. The Point Lepreau Generating Station, which returned to operation post-refurbishment in 2012, provides another 35 per cent of the provincial electricity requirements from non-emitting nuclear energy. Therefore, by 2020, it is expected that 75 per cent of New Brunswick's electricity requirements will be met by non-emitting or renewable sources.

The balance of requirements will come from a mix of renewable and non-renewable resources in order to maintain a reasonable level of generation diversity. These resource options can be found in Section 4 (Supply Options).

The key objectives served by the RPS are:

- Low and Stable Energy Prices – Integrating additional renewable energy will help protect from the cost volatility of electricity generated from fossil fuels;
- Energy Security – Developing additional indigenous renewable energy will lessen NB Power's dependence on imported fossil fuels; and
- Environmental Responsibility – Additional renewable energy will reduce NB Power's greenhouse gas and associated emissions by reducing fossil fuel electricity generation.

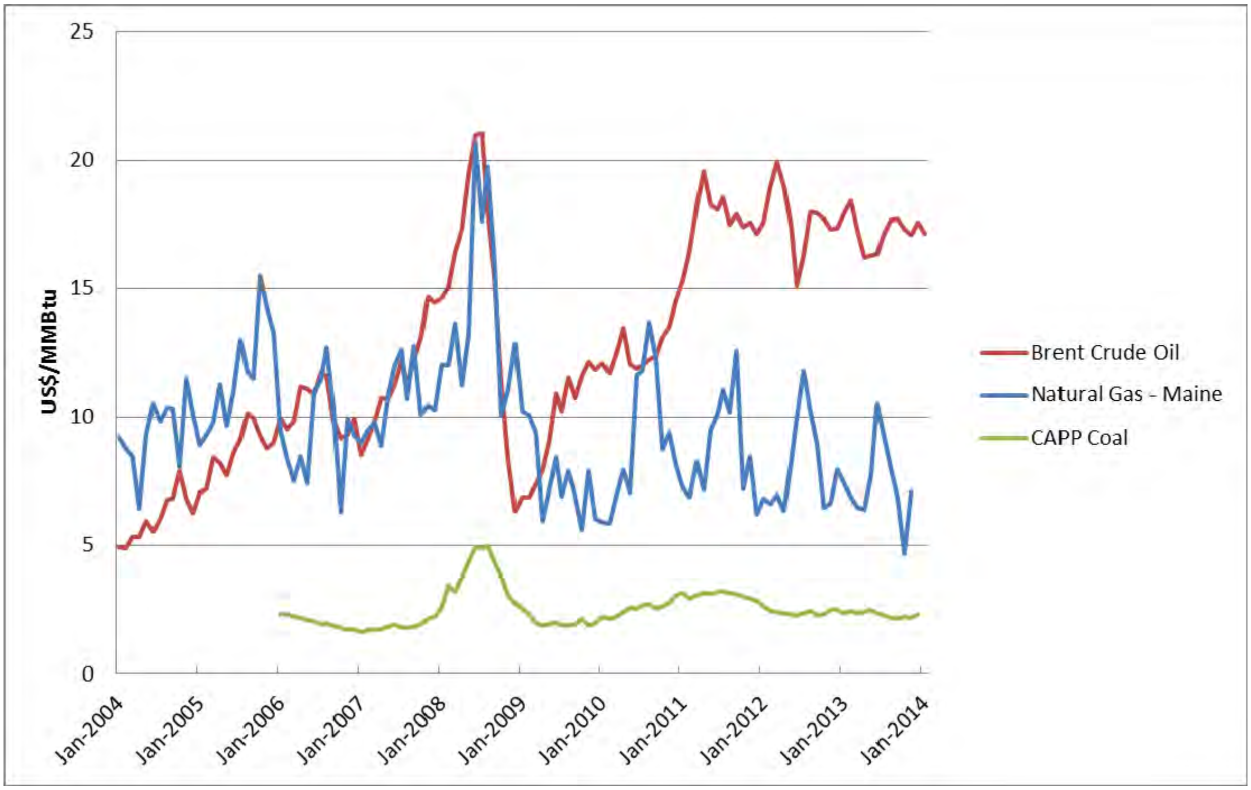
3.7. Fuel Price Forecast

It has been mentioned that NB Power has one of the most diverse power systems in North America. This means that there is a direct dependence on various sources of fuel including coal, oil and nuclear, and an indirect dependence on natural gas and biomass through power purchase agreements.

NB Power purchases coal, #6 heavy fuel oil, #2 light fuel oil and nuclear fuel. It also has exposure through PPAs, to natural gas and to wholesale market prices for electricity purchases. NB Power's fuel and purchased power costs to serve in-province electricity requirements have averaged about $600 million per year over the last 10 years.

Hydrocarbon fuel prices have had a history of volatility and uncertainty. The graph shown in Figure 18 provides an indication of how fuel prices have varied since January 2004.

Figure 18: Fuel price indices history



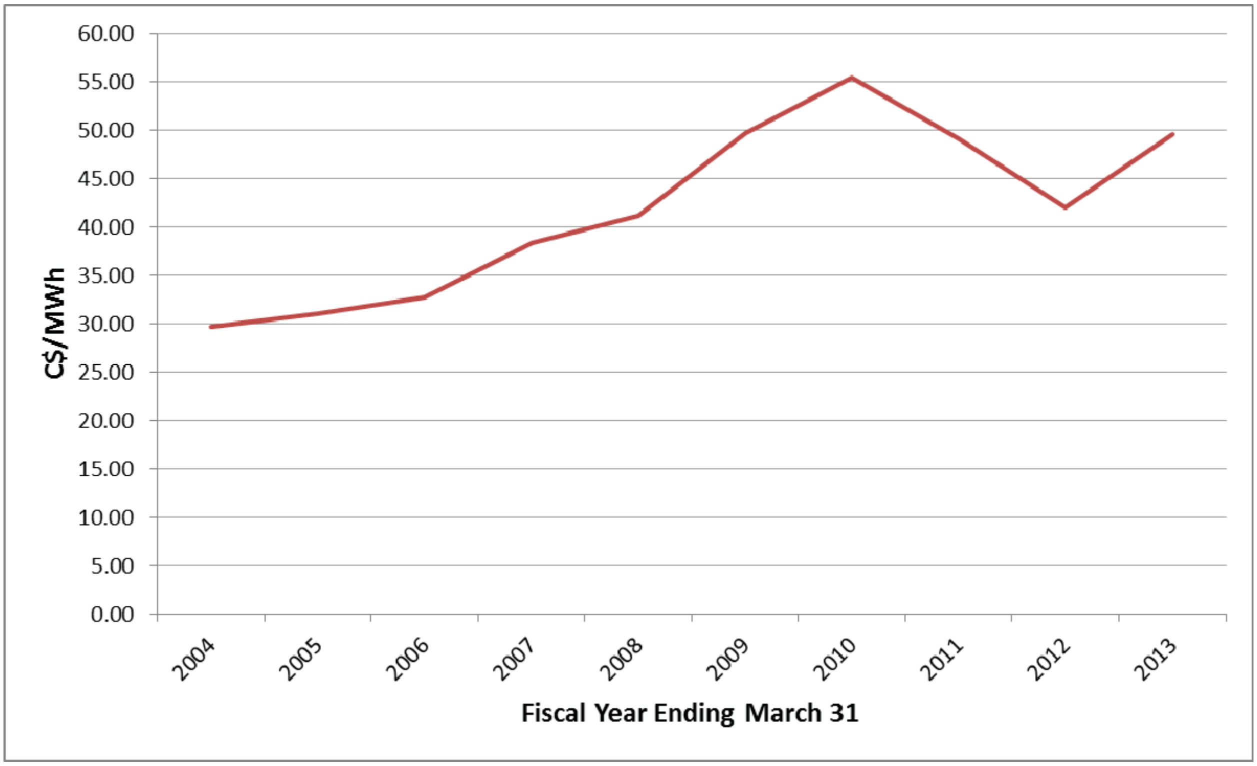
The indices are for trading hubs for the commodity indicated. There are many trading hubs for the various commodities, for example:

- Brent Crude Oil – an index that reflects world oil prices;
- Natural Gas – delivered in Maine; and
- CAPP Coal - thermal coal, from Central Appalachian region of the U.S.

The natural gas prices in Maine are indicative of the price that NB Power pays for natural gas fuel, but are not exact in that they do not account for added costs of getting the fuel to the burner. Also note that the prices shown in the previous graph are for an average index price over the applicable month. Daily prices are more volatile than monthly prices.

Fuel and purchased power prices have continually increased over the past several years with the increasing fuel and purchase power costs and increasing volumes of electricity sales. As shown in Figure 19, the average fuel and purchased power price has increased by over 60 per cent in the past 10 years. This represents an average annual growth of about 6 per cent per cent per year. Note that the calculation excludes hydro generation to remove the impact of widely varying annual production.

Figure 19: Historical average fuel and purchased power price

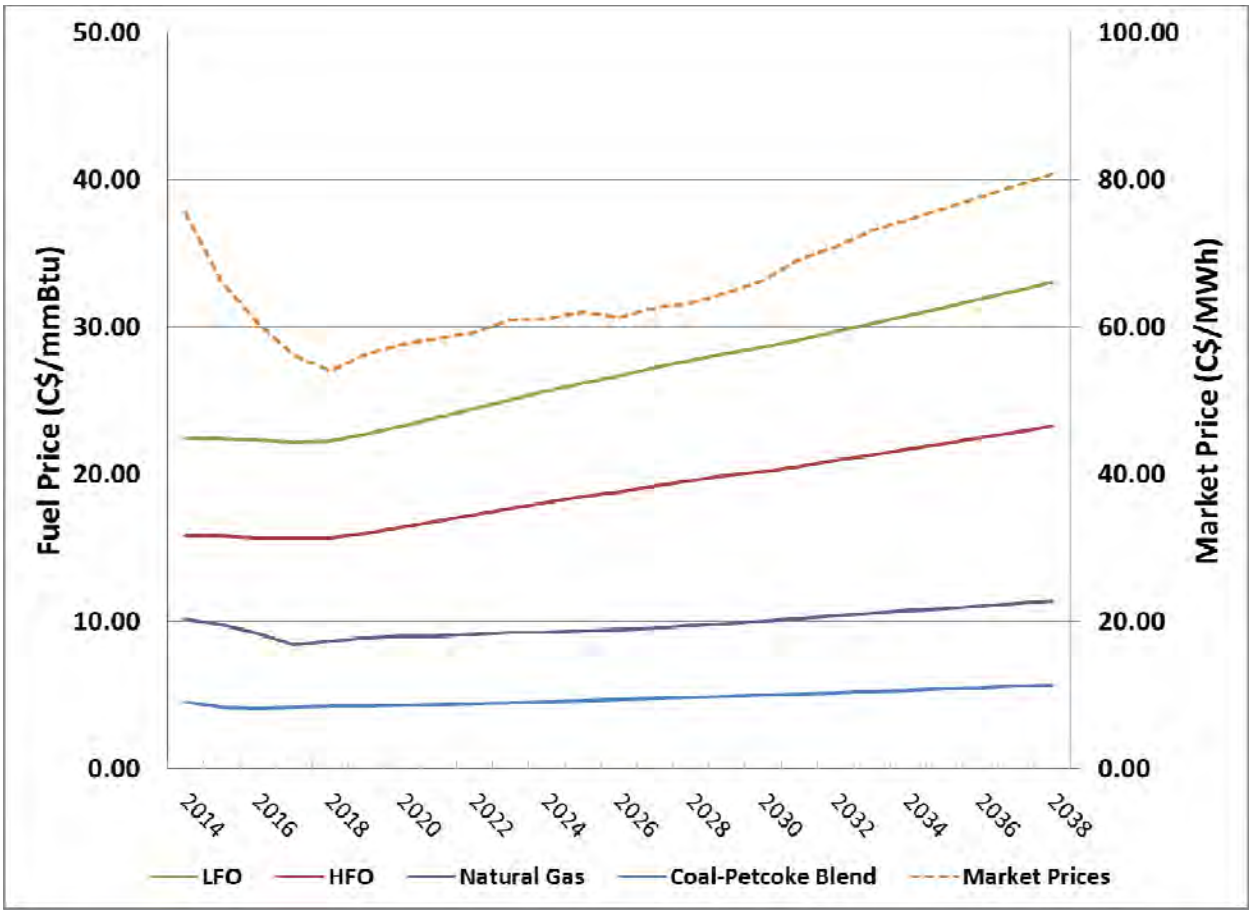


The significant variation in the price in the latter part of the period was related to the combination of fuel price variation and changes in the in-province electricity requirement. It was during the period 2008 to 2010 where in-province electricity requirement was negatively influenced because of a significant decrease in industrial load. The in-province electricity requirement then began to stabilize and increase slightly after 2010. Fuel prices also varied during this period as was shown in Figure 18.

Looking forward, the primary source of information for the long-term fuel and market price forecasts used in this IRP study was based on forecasts obtained from Platts McGraw Hill Financial (Platts).

The first three years of the fuel price forecast used in this IRP was based on the most recent available NB Power budget. The budget forecast was based on the applicable forward prices at time of budget preparation. For the years beyond the available budget numbers, forecasts were obtained from Platts. Platts is a leading source for the price assessments of commodity markets and fuel prices used in this IRP. The resulting forecast is in US dollars of the applicable year (nominal dollars). The US dollar values were then converted to Canadian dollars utilizing a forecasted exchange rate. The resulting fuel price forecast is shown in
Figure 20 with the corresponding data provided in Appendix 2.

Figure 20: Fuel price forecast



The market prices shown in the chart are Massachusetts Hub (Mass Hub) prices and are highly correlated to natural gas prices. The Mass Hub price index sets the base market price of electricity that NB Power buys and sells against. These prices are higher in the near term because of the existing natural gas pipeline congestion south of the Boston area. This restricts the flow of natural gas into the Massachusetts market which then causes an increase in both natural gas and electricity prices. It is expected that this congestion issue will be relieved over the next 3 years through expansion of pipeline capacity in the affected area. As this happens, prices of natural gas and market prices will decrease and are assumed to stabilize over the long term.

In addition to the above base fuel prices forecast, this IRP provided upper and lower bound price scenarios. This allowed for an analysis for possible future fuel prices that differ significantly from those assumed in the reference case. As a synthesis of the scenarios in this IRP, low fuel price and high fuel price cases were applied. The effect of these sensitivities is analysed in detail in section 8.4 (Sensitivity Analysis).

3.8. Long-Term Financial and Economic Parameters

3.8.1. General Introduction

An estimate or projection of the values of certain financial parameters is required to determine the levelized cost of electricity (LCOE) of each of the potential generation options. LCOE is the net present value of the total cost stream of a given generation option over its economic life to generate 1 kWh of electricity, including the cost of capital, fuel, operation, maintenance and administration, external environmental costs as applicable, and income taxes payable. LCOE is used to evaluate and compare the relative economics of each of the potential generation options. Section 5 (Results of Supply Analysis) provides the results of the LCOE analysis.

The financial parameters considered in this IRP include:

- the consumer price index;
- the electric utility construction price index;
- the foreign exchange rate; and
- the weighted average cost of capital (WACC).

These financial parameters are also used in other analyses or applications, including those related to demand-side and energy efficiency management, Strategist modelling,[20] rate impacts and generally in other net present value (NPV) analyses.

This section summarizes and documents how these estimates or projections were arrived at.

3.8.2. The Consumer Price Index

The consumer price index (CPI), which is used to adjust operation, maintenance and administration costs in future years, is projected to increase by 2 per cent per year. The projection was informed by the most recent Bank of Canada *Monetary Policy Report*[21] that was published in January 2014. It was also informed by a review of the yield spread between Canada Long Bonds versus Canada Real Return Bonds.

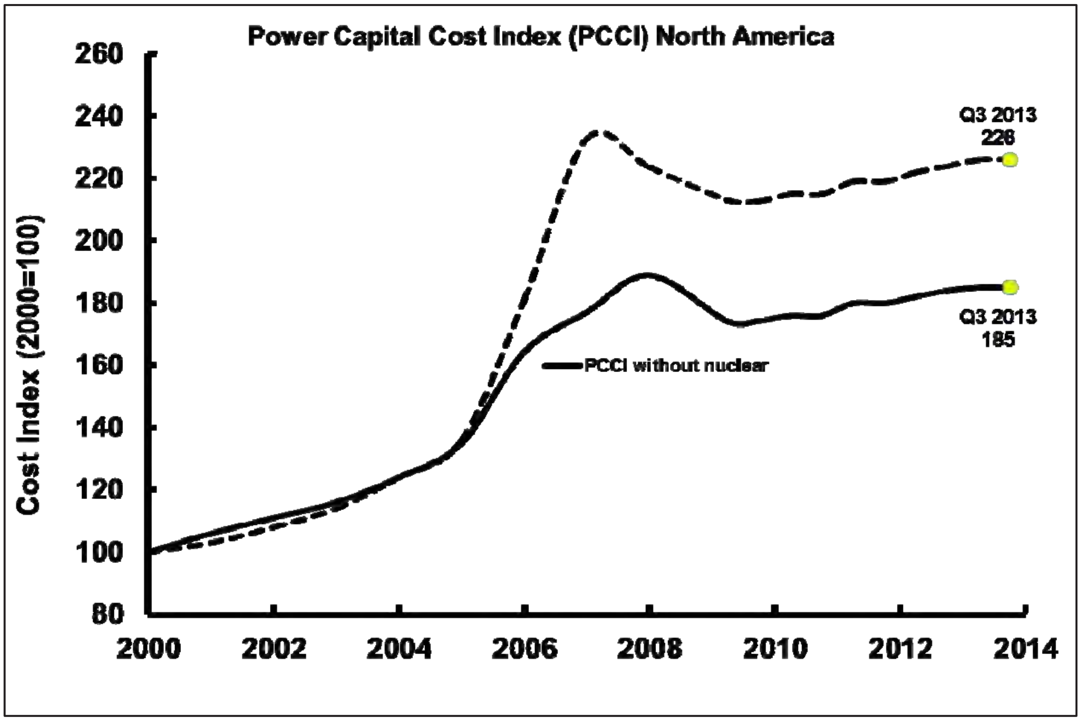
[20] *Strategist (*formally called *PROSCREEN II)* is a proprietary computer software program developed by *Ventyx,* an *ABB* company and is widely used by electric utilities for IRP purposes. The New Brunswick EUB has reviewed and approved the use of the *PROSCREEN II* model, the predecessor to the *Strategist* model, for system planning purposes.

[21] http://www.bankofcanada.ca/wp-content/uploads/2013/11/mpr-2014-01-22.pdf

3.8.3. The Construction Price Index

The electric utility construction price index is projected to escalate at 4 per cent per year, consistent with the most recent publication of Power Capital Cost Index (PCCI) North America produced by IHS CERA[22] and shown in Figure 21. Two historical construction price indices are shown, based on activity that include and exclude nuclear construction.

Figure 21: Historical Construction Price Index



This chart shows that historical growth for plant construction costs have varied between 5 per cent and 7 per cent since the year 2000. As mentioned, this growth is very dependent upon whether consideration is made that includes nuclear construction, which had significant cost increases in the 2005 to 2007 time period. More recent history, particularly in the last five years, has shown that the growth in construction costs has been stagnant at about 1 per cent per year. Although the most recent history shows slow growth, it is expected that growth in construction costs will recover in the longer term. This IRP has assumed a growth in construction prices of 4 per cent per year, slower than the long-term historical average of 5 to 7 per cent, but higher than the 1 per cent growth seen in recent history. In arriving at this projection, it was assumed that the global requirement for electricity infrastructure investment would accelerate as capital stock turnover continues with ageing infrastructure during the 2014 to 2038 planning horizon. It is expected that the prices of industrial commodities (such as

[22] IHS CERA Power Capital Cost Index (PCCI): http://www.ihs.com/info/cera/ihsindexes/index.aspx

structural steel, copper, concrete, etc.) will continue to increase in response to this continuing demand.

Sensitivity analyses have been performed in this IRP to capture uncertainties in the major assumptions. The effect of these sensitivities on future capital costs and the impact on the plan can be seen in Section 8.4 (Sensitivity Analysis).

3.8.4. The Foreign Exchange Rate

Many factors affect the exchange value of the Canadian dollar vis-à-vis the US dollar. The main factors are:

- the terms of trade (i.e., the relative prices of oil and other commodities that Canada exports vis-à-vis product that Canada imports);
- interest rate differentials between Canada and the U.S.; and
- purchasing power parity, i.e., the inflation rate in Canada vis-à-vis the U.S.

The foreign exchange rate currently stands at approximately USD/CAD = 1.10. This means that one US dollar will purchase 1.10 Canadian dollars. Over the short-term (next four years), this exchange rate is not expected to change significantly. The following is based on recent currency forwards.

	USD/CAD
2014	1.100
2015	1.107
2016	1.113
2017	1.114

The long-run exchange rate has been assumed as USD/CAN = 1.11, the average of the short-term currency forwards shown above. Foreign exchange rates have a direct impact on fuel and market prices since these are expressed in US dollars. To capture uncertainty in exchange rates, sensitivity analysis was performed to capture changes in fuel and market prices.

3.8.5. The Weighted Average Cost of Capital

A public investor such as a government-sponsored enterprise may have different costs of debt, debt ratios, etc., compared to a private investor. Therefore, the Weighted Average Cost of Capital (WACC) will have two different calculations, one that is representative of public investors, and one that is appropriate for private investors.

The Weighted Average Cost of Capital (WACC) is defined as follows:

$$WACC = r \times (1-t) \times DebtRatio + ROE \times EquityRatio$$

Where:

r is the interest rate for debt
t is the corporate income tax rate
ROE is the return on equity (after tax)

$$DebtRatio = \frac{Debt}{Debt + Equity}$$

$$EquityRatio = \frac{Equity}{Debt + Equity}$$

Figure 22 summarizes and documents how the WACCs for the two different classes of investors were calculated.

Figure 22: Weighted average cost of capital

Calculation of the Weighted Average Cost of Capital

Common assumptions

Canada Bond - Long Term	3.00%
Corporate Income tax Rate	30.00%

After-Tax Weighted Average Cost of Capital (WACC):

Developer	Credit Rating	Debt Ratio	Equity Ratio	Long Bond Rate	Spread		Guarantee Fee	Interest Rate	Return On Equity	WACC
Private	BBB-	65.0%	35.0%	3.00%	300	b.p.	0%	6.00%	16.0%	8.33%
Public	A+	100.0%	0.0%	3.00%	200	b.p.	0.65%	5.65%	0.0%	5.65%

General Remarks

1. WACC is generally used by companies to evaluate investment decisions. The rate is used to discount the after-tax cash flows arising from a given investment.
2. A reputable and creditworthy private independent power producer, such as TransAlta Corporation, has a BBB- credit rating.
3. The credit rating of government-sponsored enterprises, such as NB Power, is assumed to have similar rating to the sponsoring government entity. The credit rating of the Government of New Brunswick is A+.
4. For projects developed by NB Power, it is assumed that such projects are 100% debt-financed, and that a loan guarantee of 0.65% applies.
5. It is assumed that a private investor, would have a debt ratio of 65% with a target unlevered ROE of 11%. The corresponding levered ROE is 16%.

4. SUPPLY OPTIONS

The supply option description and parameters provided in this section were obtained from Hatch Energy (Hatch) and NB Power staff. The study provides high-level estimates of plant performance and cost data for each proposed alternative. The estimates provided in this study are order-of-magnitude estimates and, accordingly, were based on limited and incomplete data. Therefore, while the work, results, estimates and projections within the study may be considered to be generally indicative of the nature and quality of the study, they are not definitive. This means that when making final decisions on selecting and implementing supply options, more detailed engineering will be performed to provide greater certainty in the final cost estimates.

The cost estimates provided by Hatch reflect New Brunswick locations, although specific sites were not selected for the alternatives except in cases involving additions or modifications to existing NB Power generation assets.

Each renewable power alternative estimated in this study assumed a generic site location in New Brunswick (on land or offshore with power transmitted into New Brunswick's grid). In certain cases, some judgments on the energy harvest technology suitable to the available resource were made based on the information available on the nature of the resource in the province.

Performance of the thermal power alternatives were estimated at average ambient conditions and based on seawater once-through cooling. Carbon capture systems and costs of carbon were not included in the initial estimates. The impact of carbon pricing was analyzed separately in Section 8.4 (Sensitivity Analysis).

Capital costs are based on Hatch in-house data from recent similar projects, and on publicly available industry data from conferences, reports, professional papers and other publications. Referenced historical project costs were adjusted for inflation and to 2013 Canadian dollars as needed. Costs associated with construction management, engineering and project management, as well as contingencies, are based on Hatch's own experience.

Project costs include mobilization to the site, procurement and installation of the generating equipment, contingencies, permitting, engineering and management.

For some alternatives, a “Capital Cost Range” to be expected for projects in New Brunswick is provided. It is intended to account for site specific and project definition factors. Renewable power in general is harvested from relatively low energy density resources, and the methods of harvest and associated technology selection are factors contributing to a cost estimate range. The concept of a cost estimate “range” used in this study is not to be confused with estimate “accuracy.” Accuracy is a function of engineering content and can be improved by additional scope definition, site specific data and project cost elements obtained from vendor quotes (as an example).

Capital costs provided by Hatch were expressed as overnight costs and did not account for escalation, overhead costs, owner’s costs or interest during construction. However, NB Power included an interest rate during construction of 5.65 per cent, consistent with public-financed projects. Escalation was also applied to capital projects that reflected the electric utility construction price index, projected at 4 per cent per year. All other costs, including operating and maintenance (O&M) costs, were projected to increase at 2 per cent per year. Capital costs also did not include transmission interconnections or upgrade costs since these costs would be site specific. In most cases, overhead costs, owners’ costs and transmission costs would be small in comparison to the project capital costs. Therefore, the effect would be within the relative accuracy of the original estimate, which, as mentioned previously, is an order-of-magnitude estimate.

Typical plant operations and operating modes are described in support of O&M cost estimates. Costs include operators of the facility, maintenance labour and materials, and the administrative costs to provide the facility service, but exclude taxes and royalties, owner’s administrative costs at the corporate level, profit and overhead. All O&M costs presented are first year costs, not levelized costs.

Operating costs do not include fuel costs. However, information is provided on typical heat rates for each thermal power technology. Operating costs may also include a provision for major capital renewals expressed in terms of cost per kW, per year. The present value of the expected capital renewal expense was used to derive these estimates.

The following section provides all supply options considered in this IRP. These options include both conventional and renewable options, most of which have been in commercial operation. Consideration is also given to projects that are pre-commercial in nature, and high-level costs are provided for these options. It should be emphasized that these options and costs are based on information and experience available to date, and that no provision has been made to predict what new options may be available in the future, including potential improvement in costs. They reflect the most recent “snapshot” of available options and costs. All options, parameters and costs can be seen in tabular form in Appendix 3.

4.1. Conventional Supply Options

4.1.1. Nuclear

How is electricity generated using nuclear fuel?
Power is produced from controlled nuclear reactions and the heat generated from the nuclear reactions converts water to pressurized steam, which is then used to generate electricity. According to the Canadian Electricity Association (CEA), 15.3 per cent of the electricity generated in Canada came from nuclear power in 2012.

NB Power owns and operates the Point Lepreau Nuclear Generating Station. This station is comprised of one Candu 6 unit constructed during the period 1975-1983 at a cost of approximately $1.4 billion (1983 dollars). The unit was originally designed with a net capacity of 635 MW. The original plans for the facility as developed by Atomic Energy of Canada Limited (AECL) allowed for a two-unit plant.

Following approximately 25 years of operation, a refurbishment project began in 2008 and, after several delays, the unit was returned to service in November 2012. The overall cost of the refurbishment was approximately $2.4 billion (2012 dollars) and is expected to operate for the next 27 years. The refurbished facility is now more efficient and has a net capacity of 660 MW.

Figure 23: The Point Lepreau Nuclear Generating Station

Nuclear Power Plant Development Activities in Canada

Candu Energy Inc. (the private sector company that purchased AECL's generation business) is developing the Advanced Candu Reactor (ACR)–1000 which is described as a generation III+, 1,200 MW heavy water reactor. Design work has advanced to a preliminary stage and the Canadian Nuclear Safety Commission's (CNSC) pre-project design review completed in December 2010 concluded there were no fundamental barriers to licensing the unit in Canada. Ongoing development work on the ACR–1000 has resulted in design changes that have also been applied to the Candu 6 design. The current Candu 6 design is referred to as Enhanced Candu 6 (EC6).

Areva Inc. of France is ranked as the top firm in the global nuclear power industry. The company reported in July 2013 that its ATMEA1 reactor, which it is developing jointly with Mitsubishi Heavy Industries, has passed the first stage of the pre-certification process used by the CNSC. The second and third stages will consist of in-depth analysis of the reactor design in order for the certification process to begin under what it refers to as "the best possible conditions." This reactor has similar features to those of Areva's European Pressurized Reactor (EPR).

In 2009, Ontario received bids from AECL, Areva and Westinghouse Electric for installation of two additional units at Ontario Power Generation's Darlington Nuclear Station. AECL's bid for two 1,200 MW ACR–1000 units to be operational by 2018 was indicated to be the only one of the three bids that was compliant with the terms of the request for proposals. It is reported that the project cost would be approximately $10,800 per kW. The Province of Ontario did not move forward with the project. The Province continues with rehabilitation work on the existing fleet of nuclear generating units.

Nuclear Power Developments in Other Areas

The World Nuclear Association reports that there are currently 68 nuclear units under construction around the world. China, Russia, India and South Korea account for approximately 75 per cent of these. Examples of projects in Finland and the U.S. are discussed below.

Finland currently has two nuclear power plants in service, each with two units, with a total net capacity of approximately 2,740 MW. These plants typically produce about 30 per cent of the country's annual electricity requirements. In 2002 the country's parliament approved construction of a fifth unit to be in operation by 2009 at the site of one of the existing plants. The owner signed a contract with Areva and Siemens in December 2003 for an EPR reactor with an output of 1,600 MW at a cost of approximately €3.3 billion. The project has undergone delays and cost overruns and is reported to now be about 80 per cent complete. It is reported by the World Nuclear Association that the project will now cost about €8.5 billion ($7,200 per kW) and will not enter commercial operation until 2016.

There are currently five new nuclear units under construction in the U.S. Georgia Power is adding units 3 and 4 at its Plant Vogtle. These are Westinghouse AP1000 units with an output of approximately 1,117 MW per unit. The company reports an estimated cost of $6,300 per kW. Two similar units are being installed by South Carolina Electric & Gas at the existing V. C. Summer nuclear station in South Carolina. The fifth unit under construction, also a Westinghouse pressurized water reactor, is the Tennessee Valley Authority's Watts Bar unit 2. Construction of this unit was restarted in 2007 (from an estimated 80 per cent completion stage) and is expected to be completed in late 2015 at a cost of $4.0 - 4.5 billion. This unit is expected to be the first new nuclear generating unit to be commissioned in the U.S. in 20 years.

Cost Estimates for New Nuclear Generating Units

In its *Annual Energy Outlook 2013,* the U.S. Energy Information Administration provides an overview of existing nuclear generating capacity and projections of uprates, retirements and new builds over the period to 2040. As of 2011, 104 nuclear reactors with a capacity of 101,000 MW were operating in the U.S. providing just under 20 per cent of the country's total electricity supplies. The report's reference case projection for the year 2040 includes 19,000 MW of new nuclear capacity made up of 8,000 MW of uprates and 11,000 MW of new builds. The report states that the cost of new nuclear capacity is estimated to be in the $5,400 per kW (2011 US dollars) range excluding financing costs and interest during construction. The EIA reports fixed O&M costs in the $90 per kW-year range and variable O&M costs of 0.2 cents per kWh.

4.1.2. Natural Gas

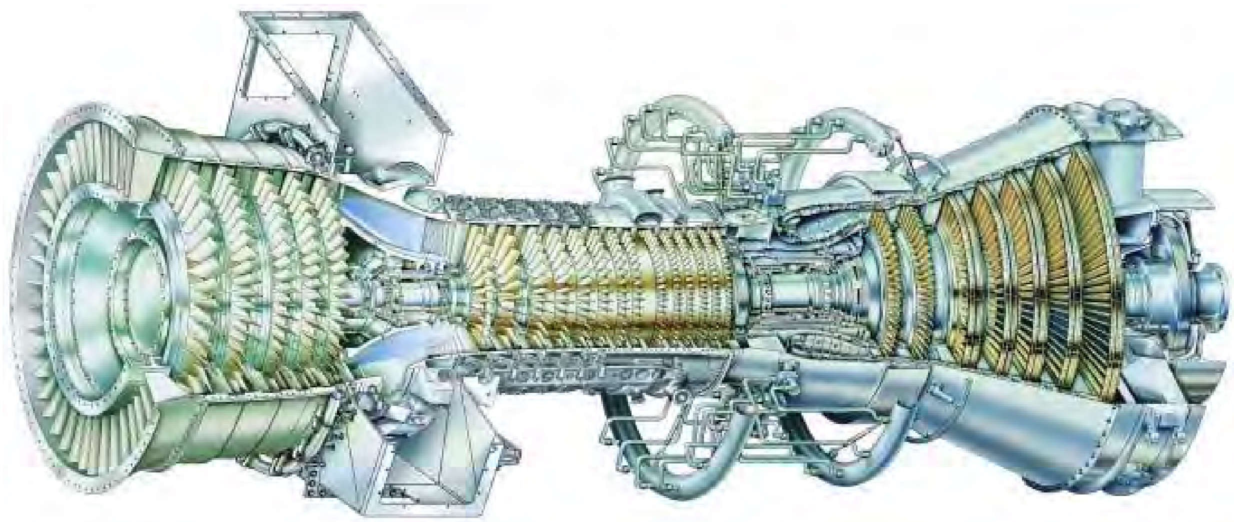
How is electricity generated using natural gas?

A combustion turbine is a rotary engine that uses gas to generate electricity. An air/gas mix is ignited in a combustion chamber. The resulting gas flow is directed to the blades of a turbine which turn a shaft. The rotating shaft is connected to an electrical generator which converts the rotating shaft motion into electrical energy.

4.1.2.1. Combustion Turbines

Combustion turbines (CTs) are typically used for specialized needs and are available in unit sizes from as low as 10 MW up to 150 MW. They are tailored to system-peaking requirements or back-up supply to increase system security, and typically operate below 20 per cent capacity factor. The capital costs for these units are relatively small, but efficiencies are low in comparison to base load facilities so the fuel costs can be significant. This study has provided two options, similar in size of approximately 100 MW, but with two efficiency points.

Figure 24: Cross section of a GE LM6000 combustion turbine



A high efficiency option was included in this study using a nominal 100 MW natural gas-fired simple cycle combustion turbine based on two GE LM6000PH combustion turbine generators with dry low NO_x combustors. The mid-efficiency option, assuming a nominal 90 MW natural gas-fired simple cycle combustion turbine, was based on one Alstom GT 7EA combustion turbine generator with dry low NO_x combustors. The mid-efficiency combustion turbine plant option is a newer technology than the combustion turbines located at NB Power's Ste. Rose and Millbank Generating Stations, which employ the older model GT11N1 and operate on diesel fuel.

Post-combustion emissions controls (i.e., SCR – selective catalytic reduction) for both CT options were assumed not to be required as a CT generator is capable of achieving NO_x emissions of less than five parts per million (ppm).

Pipeline gas was assumed to be available at adequate pressure (30 bar (g)) to support combustion turbine operation at base load under all ambient conditions without on-site gas booster compressors.

The project capital costs were estimated based on a factored cost methodology, using Hatch in-house data and recent vendor quotes for the major equipment.

The operational costs for this alternative include costs for operators of the facility, maintenance labour and materials and the administrative costs to provide the facility service. Non-fuel operating and maintenance costs were estimated based on a peaking duty mode of operation with approximately 500 hours of operation and 150 starts per year. Staffing was assumed to include four operators, two maintenance personnel and an allowance for administration/management staff.

Project lead time, from notice to proceed to commercial operation date, would be two years, based on combustion turbine delivery time of 15 months after receipt of order. This combustion turbine plant would have an accounting life estimated at 25 years.

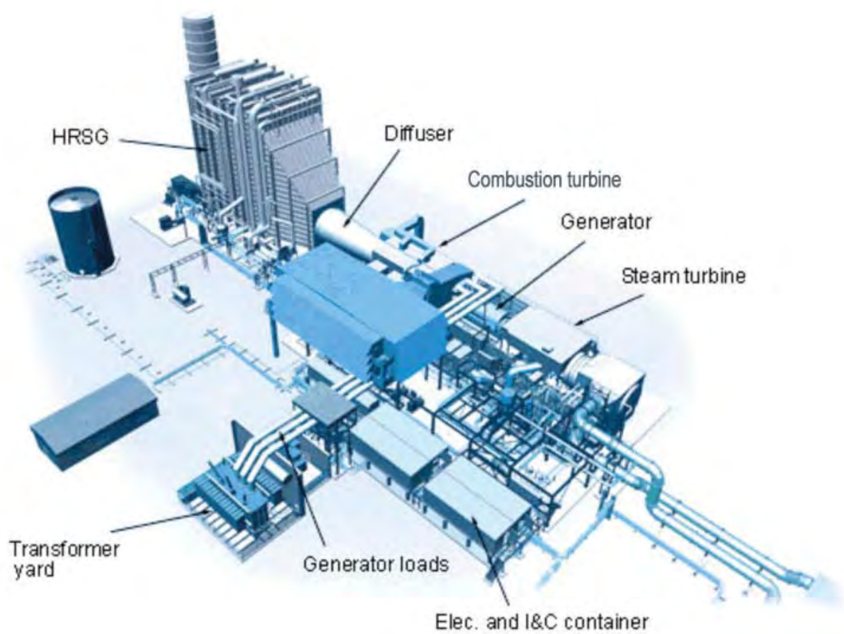
4.1.2.2. Combined Cycle

In a combined cycle power plant, a combustion turbine (normally operating on natural gas) generates electricity. The waste heat from the exhaust is used to make steam to generate additional electricity via a steam turbine. This last step enhances the efficiency of electricity generation. Typical thermal efficiencies of combined cycle power plants range between 50 to 60 per cent, depending on the equipment used and the configuration. Typically, about one-third of the electricity is generated from the combustion turbine and two-thirds from the steam turbine generator.

A combined cycle system includes single-shaft and multi-shaft configurations. The single-shaft system consists of one combustion turbine, one steam turbine generator and one Heat Recovery Steam Generator (HRSG). This configuration is typically called a 1x1x1 arrangement and is shown in Figure 25. The combustion turbine generator set and steam turbine generator set are coupled in a tandem arrangement on a single shaft. The key advantage of this single-shaft arrangement is its operating simplicity with higher reliability than multi-shaft configurations. Further operational flexibility is provided with a steam turbine that can be decoupled for simple cycle operation of the combustion turbine as stand-alone operation.

In some cases the construction of these systems can be phased so that the combustion turbines are built first and operated, with the steam system added later.

Figure 25: Typical combined cycle system configuration



This study included three sizes of combined cycle plants; a large size in the order of 420 MW, a medium size of about 285 MW and a small size of about 120 MW, each with varying efficiencies.

The large combine cycle generation option is for a nominal 420 MW natural gas-fired combined cycle power plant. The reference plant would be a 1x1x1 arrangement based on a Mitsubishi M501GAC (air-cooled) combustion turbine generator with dry low NO_x combustors, triple pressure reheat HRSG with SCR and a nominal 140 MW steam turbine generator. Thermal efficiency is approximately 57 per cent.

The medium combined cycle option is for a nominal 285 MW natural gas-fired combined cycle power plant. The reference plant would be a 1x1x1 arrangement based on a General Electric 7241FA combustion turbine generator with dry low NO_x combustors, triple pressure reheat HRSG with SCR and a nominal 100 MW steam turbine generator. Thermal efficiency of this option is approximately 56 per cent.

The small combined cycle option is for a nominal 120 MW natural gas-fired combined cycle power plant. The reference plant would be based on a 2x2x1 arrangement that includes two GE LM6000PH combustion turbine generators with low NO_x combustors, two heat recovery steam generators, and one steam turbine generator. Thermal efficiency of this option is approximately 52 per cent. Two options of this smaller version of combined cycle were included: one with once-through cooling water access and one that included a cooling tower for plant cooling. The latter would be required if access to seawater was not readily available.

The plant location assumed for all options, unless otherwise specified, would be located adjacent to an existing power generation facility on the coast and would employ a once-through seawater cooling system. Site average performance was estimated based on an elevation of 8 m AMSL and annual average temperature of 5.5ºC, and an annual seawater inlet temperature of 7.5ºC.

Post-combustion emissions controls for these options were included to reduce NO_x emissions to less than 5 ppm. An oxidation catalyst for carbon monoxide (CO) abatement was not included as the combustion turbine CO emissions are low and the pollutant is not specifically addressed in Environment Canada's *National Emission Guidelines for Stationary Combustion Turbines.*[23]

It was assumed that pipeline gas would be available at adequate pressure to support combustion turbine operation at base load without on-site gas booster compressors.

The overnight total project costs were estimated based on a factored cost methodology using Hatch in-house data and recent vendor quotes for the major equipment. Costs include three generator step-up transformers. Also, it was assumed that a piped municipal water supply and a sanitary sewer up to the plant fence would be available, as well as natural gas lateral piped to a metered regulating station located adjacent to the plant fence.

The operational costs for this option include costs for operators of the facility, maintenance labour and materials, and the administrative costs to provide the facility service. Non-fuel operating and maintenance costs were estimated based on an intermediate duty cycling mode of operation with approximately 7,000 hours of operation and 75 starts per year. Fixed costs include operations and maintenance staff, administrative costs and fixed maintenance, and long-term service agreement costs. Variable O&M costs include major planned maintenance parts and labour, unscheduled maintenance, SCR catalyst replacement and disposal, chemicals and consumables and municipal water.

Project lead time would be approximately 36 months. All combined cycle plant options would have an accounting life of 25 years.

4.1.3. Hydro

How is electricity generated using hydro resources?
Hydroelectric power is generated from the movement of water from a reservoir through a channel or pipe into a turbine. The flowing water makes contact with turbine blades, causing the shaft to rotate. The rotating shaft is connected to an electrical generator that converts the rotating shaft motion into electrical energy. A hydroelectric facility requires a dependable flow

[23] http://www.ccme.ca/assets/pdf/pn_1072_e.pdf

of water and a reasonable height of fall of water commonly called the head. According to the CEA, 63.3 per cent of the electricity generated in Canada came from hydro in 2012.

4.1.3.1. Grand Falls Additional Power

The existing Grand Falls Generating Station is located on the St. John River. The station is situated on an oxbow-like turn in the river in the town of Grand Falls. The initial water drop in the river is at the falls, and then cascades to the powerhouse location where the river widens to a gentle flow. The total drop in elevation is approximately 39 m.

The existing station, shown in Figure 26, was built in the mid-1920s. It is comprised of a concrete gated control structure near the crest of the falls, a riverbank intake structure, a concrete-lined tunnel in bedrock (inside diameter of 7.5 m), a surge tank, a short, steel penstock and a four-unit powerhouse at the base of the gorge. The powerhouse is comprised of four units with an initial installed capacity of 60 MW. As a result of unit upgrades in the mid-1990s, the powerhouse capacity is now 66 MW.

Figure 26: The Grand Falls Generating Station

The addition of a new hydroelectric facility adjacent to the existing 66 MW station at Grand Falls is technically feasible and could be readily constructed. Additional power at this site would add to NB Power's portfolio of renewable energy generation, further demonstrating a commitment to environmental leadership.

The project would have many advantages, including:

- low project cost per kW;
- use of existing water storage structures;
- low environmental effect;
- improved use of water resources by utilizing more of the available water and decreasing spill at the site;
- all land for the proposed project is already owned by NB Power; and
- the ability to carry out the entire construction without shutting down hydroelectric production at the existing generating station.

The new construction and main equipment that would be required for the new facility includes:

- a power intake structure – concrete structure with trash racks, steel vertical gate and stop logs;
- a drop shaft immediately downstream of intake, to an approximate 700 m long power tunnel, running parallel with the existing tunnel;
- a surge tank;
- a powerhouse located just west of the existing four-unit powerhouse; and
- one or two vertical Francis turbines.

The anticipated additional annual generation would be approximately 300 GWh (with 100 MW installed capacity).

Figure 27: Artist's rendition of the additional power project for Grand Falls

Project lead time would be approximately 48 months. This hydro plant would have an accounting life of 100 years (provided that upgrades occur after 50 years).

4.1.3.2. High Narrows

The proposed High Narrows project is located in northern New Brunswick, south of the city of Bathurst. The project site is approximately 12 km upstream of NB Power's existing Nepisiguit Falls Generating Station (previously known as Great Falls).

Figure 28: NB Power's existing Nepisiguit Falls Generating Station

A pre-feasibility study was completed in 1980 by Rosseau, Sauvé, Warren Inc. (RSW) that evaluated the feasibility of harnessing hydroelectric potential at various sites along the Nepisiguit River. As a result of that work, the High Narrows project was determined to be a viable option for a potential hydroelectric development.

The addition of a new hydro station on this river would add to NB Power's portfolio of renewable energy generation.

The project would have many advantages, including:

- attractive project cost per kW;
- complementing the energy production at the existing Nepisiguit Falls Generating Station; and
- dam construction fill materials are available in abundance near the proposed dam site.

Main structures and equipment required for the proposed hydroelectric facility include:

- a diversion tunnel;
- a zoned earthfill dam;
- a concrete gated spillway;
- an intake structure;
- penstocks;
- a surface powerhouse; and
- three vertical Francis turbines.

Detailed hydro-technical analysis, including power and energy computer simulations of both the proposed new station at High Narrows and the existing Nepisiguit Falls Generating Station, yield the following options and incremental energy estimates:

- 20 MW and 71 GWh per year;
- 30 MW and 108 GWh per year;
- 40 MW and 148 GWh per year; and
- 60 MW and 180 GWh per year.

The 40 MW option was selected for evaluation in this IRP. A project schedule was prepared and consists of all stages of project development, including the environmental process, engineering, tendering, turbine/generator supply and construction.

For the 40 MW option, the project lead time would be approximately 60 months. This new hydro plant would have an accounting life of 100 years (provided that upgrades occur after 50 years).

4.1.4. Interconnection Purchases

The New Brunswick transmission system has been strategically designed to provide reliable energy to in-province customers while also providing a means with neighbouring utilities to buy and sell electricity through interconnections. These interconnections allow NB Power to purchase electricity at various times when the cost to supply electricity from in-province sources becomes more costly than market prices. But the interconnections also allow NB Power to consider options to purchase electricity from another region on a long-term contractual basis (25 years) that then can be used to defer the need to build new generation that will be required in the long-term to meet in-province requirements. There are several regions where NB Power can purchase electricity; two regions of particular interest, because of the potential availability of electricity from renewable hydro resources, are Quebec and Newfoundland and Labrador.

There remains uncertainty with respect to final terms and conditions for these contractual purchases and the assumptions with respect to pricing alternatives. For this study it was assumed that firm capacity would be priced at equivalent to the installed capital costs of new combustion turbines with energy priced at market prices.

4.1.4.1. Lower Churchill

The Churchill River in Labrador is a significant source of renewable electrical energy. However, the potential of this river has yet to be fully developed. The existing 5,428 MW Churchill Falls Generating Station began producing power in 1971, and harnesses about 65 per cent of the potential generating capacity of the river. The remaining 35 per cent is located at two sites on the lower Churchill River, known as the Lower Churchill Project.

Figure 29: Location of the Lower Churchill Project

The Lower Churchill Project consists of two of the best undeveloped hydroelectric sites in North America:

- Gull Island, which is located 225 km downstream from the existing Churchill Falls Generating Station. The 2,250 MW project at Gull Island has the potential to produce an average of 12 terawatt hours (TWh) of energy per year; and
- Muskrat Falls, which is located 60 km downstream from Gull Island. The 824 MW project at Muskrat Falls has the potential to produce an average of 5 TWh per year.

Figure 30: Artist's rendition of the Gull Island project

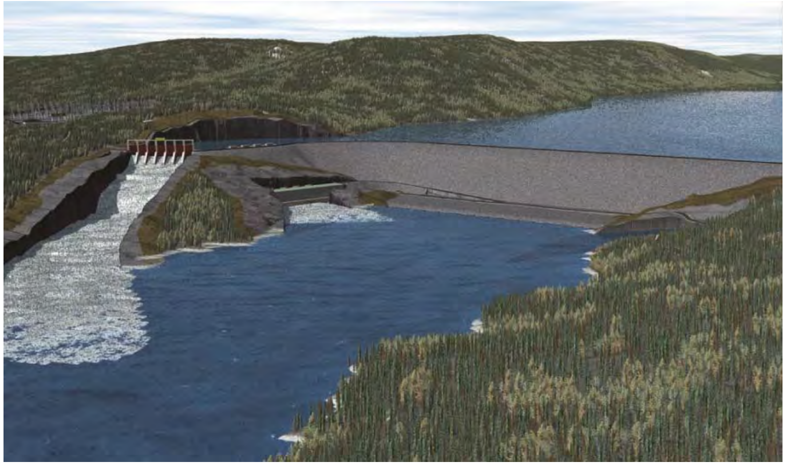
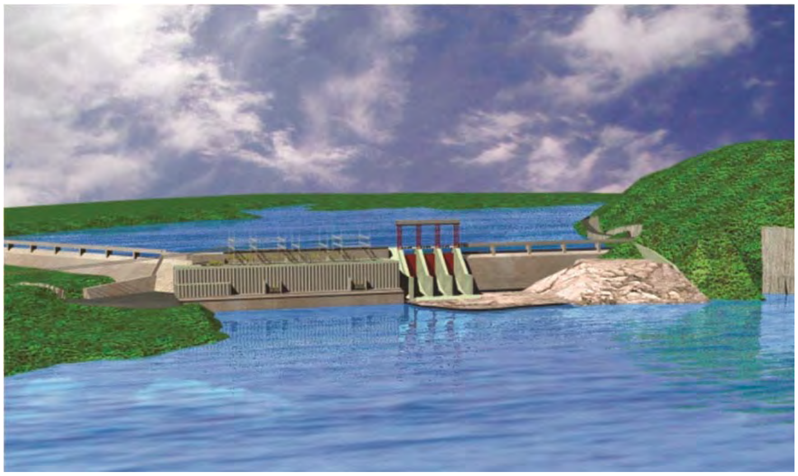


Figure 31: Artist's rendition of the Muskrat Falls project



This much needed resource of clean and stable renewable energy provides the opportunity for Newfoundland and Labrador to meet its own domestic and industrial needs in an environmentally sustainable way, with enough power remaining to export to other jurisdictions where the demand for clean energy continues to grow.

Nalcor, the Crown-owned parent company of Newfoundland and Labrador Hydro, has plans to develop the Muskrat Falls project and transmit hydropower via a 1,200 km HVDC link from Labrador to Newfoundland's Avalon Peninsula near St. John's. Another HVDC link will connect the power system of the island of Newfoundland to the Nova Scotia power system.

The Muskrat Falls project has some potential to provide NB Power with capacity and renewable energy by 2017 via Nova Scotia or Quebec. Once completed, this electricity source could reduce New Brunswick's dependency on imported hydrocarbon fuels and, over the longer term, provide replacement capacity for the capital stock turnover of NB Power's existing fossil fuel resources for 40 years or more. Newfoundland's own needs and a contractual commitment for supply to Nova Scotia reduces this potential.

A subsequent development of the Gull Island project would increase the resource potential.

4.1.4.2. Other Interconnection Purchases – HQ Expansion Projects

Hydro-Québec (HQ) continues to develop Quebec's hydroelectric power potential. The Eastmain-1-A/Sarcelle/Rupert Project was completed in 2013. This project increased capacity by 918 MW and 8.7 TWh of energy. The Romaine Project, which started in May 2009, will add 1,550 MW of capacity and 8 TWh once completed in 2020. The installed capacity of HQ's hydroelectric generating fleet is nearly 1,000 MW greater than in 2008.

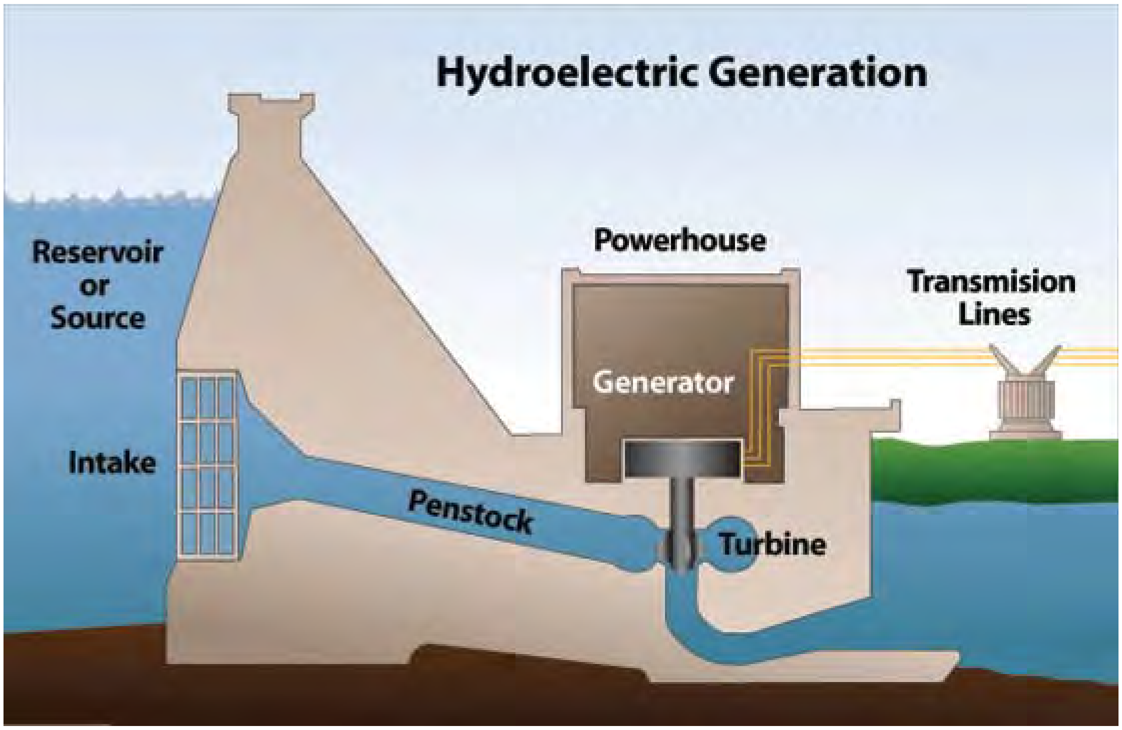
4.2. Alternative Supply Options

4.2.1. Small Hydro

How is electricity generated using small hydro?
Although there is no consensus by industry on the definition of "small" hydro, the upper limit is generally around 10 to 20 MW. See section 4.1.4 (Hydro) for details on how hydroelectricity is generated. Many rivers exist in New Brunswick that could offer favourable conditions for low-impact run-of-river hydro developments. The advantage of this type of system is that it normally has a minimal impact on the ecosystems, and on fish habitat and passage.

For this cost evaluation, the small hydro plant considered has a capacity of 20 MW, slightly higher than the Canadian definition,[24] but within the generally recognized range.

Figure 32: Typical small hydro configuration



Several candidate sites for small hydro development within New Brunswick were identified in a 1984 study by Monenco.[25] This study, as well as a recent survey[26] of undeveloped hydropower

[24] International Association for Small Hydro (IASH), 2009

potential in province, suggests that opportunities exist for further hydropower development with several candidate sites that can deliver or exceed the power production assumed in this cost review.

Head is of vital importance in a hydro plant cost estimate (the lower the head, the larger the water passages in the water transport and hydraulic equipment). In New Brunswick, existing sites are all considered to be low- to medium-head sites where head does not exceed 40 metres.

The undeveloped (green field) site capital cost estimates were based on Hatch experience and various industry publications and references. In general, the capital costs estimates provided by the various industry publications and references were typically based on historical experience and plant data, and are meant for high-level estimation purposes only. It is important to note that specific site details may have a significant impact on total project cost and feasibility.

These details can include:

- Topography;
- type of site/scheme (run-of-river, natural reservoir or man-made reservoir);
- access to the undeveloped site;
- available head and flow;
- civil structural requirements;
- spill capacity requirements; and
- distance to transmission systems.

Site-specific details and requirements must be carefully considered and fully explored in order to properly assess impact on project economics.

Operating and Maintenance (O&M) cost estimates for a 20 MW small hydro site were developed based on average industry costs for a wide variety of plant sizes and locations using various benchmarking methods. Because annual O&M costs for any given unit or plant can vary significantly depending on many factors, benchmarking methods were used that were based on published statistical data gathered from hydro facilities across North America.

Based on Hatch experience and industry statistics, development time frames from the concept to online date for hydroelectric facilities can range significantly depending on the complexity of the project.

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[25] "Identification of Environmentally Compatible Small Scale Hydroelectric Potential in Atlantic Canada", Monenco Limited, January 1984.
[26] http://www.eem.ca/index.php/case-studies/survey-of-canadian-hydropower-potential

According to the Canadian Hydro Association in 2006, on average, a hydropower project requires 8 to 12 years of preparation, from the preliminary step to its commissioning. Similarly, in 2006 and based on a range of reports, the Ontario Power Authority forecasted construction lead times for projects 10 MW or less to be approximately four to seven years.

The expected service life for new hydroelectric facilities is typically 50 years, with civil structures exceeding 100 years. Many facilities in North America have surpassed 100 years of service as a result of receiving life extensions every 20 to 40 years.

While the overall service life on many components is typically 50 years, it is noteworthy that certain components typically wear out before the end of the service life and need to be replaced or refurbished.

The following is a list of these components and each corresponding typical expected life.

Figure 33: Expected life of hydro components

Component	Typical expected life
Water conveying and control structures (channels and tunnels, gates and associated cranes, penstocks, surge alleviation facilities, intake valves)	50 years
Turbine	50 years
Governor system	50 years
Generator (rotor, stator, bearings, excitation systems)	35 years
Generator power transformer	35 years

4.2.2. Wind

How is electricity generated using wind?
Wind power is generated from the movement of wind passing the blades of a wind turbine. The rotating shaft of the turbine is connected to an electrical generator which converts the rotating shaft motion into electrical energy. Wind projects continue to develop at a rapid speed globally. According to the CEA, wind accounted for 1.5 per cent of the electricity generated in Canada in 2012.

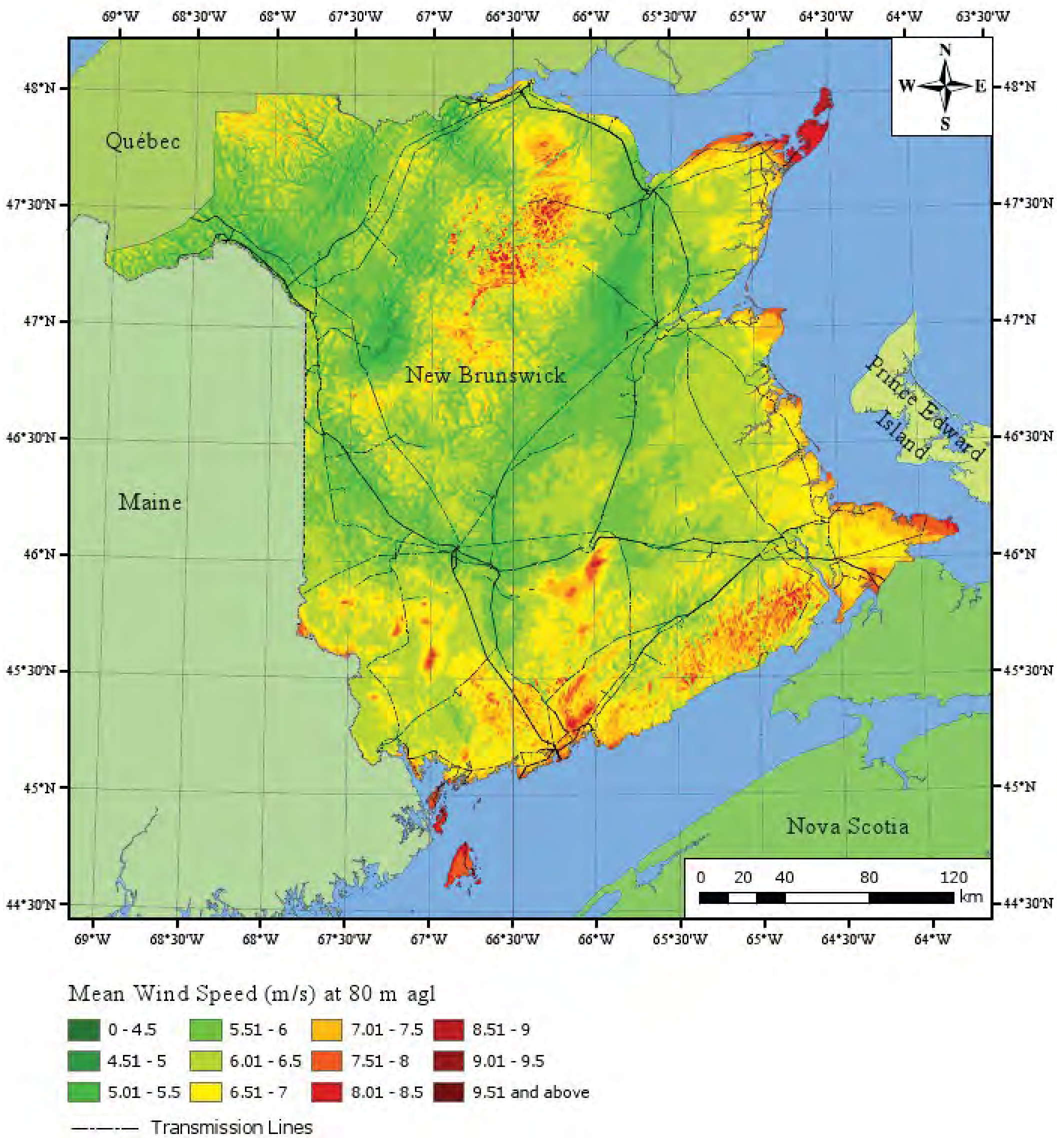
New Brunswick currently has 150 MW of installed nameplate wind capacity at the Kent Hills Wind Farm (see Figure 34) and 99 MW at the Caribou Mountain Wind Park with an additional 45 MW located in Lameque. According to the Canadian Wind Energy Association (CanWEA), and as of January 2013, Canada has about 7,000 MW of wind capacity installed. Much of this wind generation is located in Ontario, Quebec and Alberta.

Figure 34: TransAlta's Kent Hills Wind Farm, New Brunswick's first wind development

The majority of New Brunswick has average wind speeds of 6 to 7 m/s, with pockets over 7.5 m/s (at 80 m) (see Figure 33). These wind velocities are favourable to additional commercial-scale wind power development and are comparable to other areas in Canada with significant utility-scale activity (for example, the west coast of Lake Huron in Ontario). A report by Ea Energy Analyses of Denmark indicates that there is strong potential for wind development of up to 7,500 MW in New Brunswick by 2025.[27]

[27] http://www.ea-energianalyse.dk/reports/725_large_scale_wind_power_new_brunswick.pdf

Figure 35: Mean wind speeds in New Brunswick



Costs for two wind farms were considered in this study, a small-scale farm of 10 MW and a larger wind farm of 50 MW. Wind turbine unit size has some influence on capital cost; generally, but not universally, the larger the unit size, the lower per kW cost. For this IRP, plants based on either 1.5, 1.65 or 2.0 MW units were assumed.

There are four primary elements to wind project costs as shown in Figure 36.

Figure 36: Elements of costs for wind projects

Element	Portion of costs (per cent)	Includes
Generating equipment	65-75	the wind turbine blades, nacelle and tower, as well as commissioning costs
Mechanical/civil balance of plant	12-14	the construction of turbine foundations, crane pads, access roads and the erection of turbines
Electrical balance of plant	8-10	collection system, substation, switchgear and transmission interconnection
Project development (owner and consultants)	4-8	regulatory requirements, permitting, Environmental Impact Assessment, project management

The capital cost estimates provided in Appendix 3 were based on Hatch experience with wind developments in Canada up to 200 MW in size, as well as on a GL Garrad Hassan assessment of capital and operational expenditures for wind farms prepared for the Canadian Wind Energy Association [GLGH 2012][28].

The economics of a wind development project are heavily influenced by site-specific factors such as wind resource (which affects the machine class and hub height) and topography (the primary factor in transportation, civil and electrical costs). The main capital replacements over the project's lifecycle are turbine blades, gearboxes, and pitch and yaw systems. The necessities of these replacements are dependent on site conditions and vary by turbine manufacturer (some manufacturers produce direct-drive generators with no need for a gearbox).

Wind power is a relatively mature business with costs dominated by the turbine supply. The turbine supply cost is impacted by a number of site-specific factors including machine class, swept area (power output), hub height, transportation and erection. Non-site factors include technology selection (gearless versus geared, for example). Turbine costs in Hatch's database have varied by as much as $600 per kW and by $400 per kW in the GLGH report. The costs at the high end of the range would likely stem from the installation in isolated arctic projects where logistics, construction equipment and materials are extremely expensive to bring on site. However, breaking down the range of turbine costs into site and non-site specific factors was not attempted in this study. The other site-specific cost factor is the balance of plant category (civil/electrical), which varies by terrain and turbine density.

[28] http://www.canwea.ca/pdf/Assessment_Est-Cost-of-Wind-Energy_BC.pdf

One study of O&M costs for wind turbines produced a cost range of 1.5 to 2 per cent of original turbine investment [DWEA, 2009], or approximately $32 per kW per year (at 1.75 per cent). Add to this the costs associated with balance of plant (mainly the substation) and the total O&M cost increases beyond the operating expenditures (OPEX) for generating equipment alone. However, with increasing North American data about actual OPEX and many machines coming out of warranty, more evidence is presenting itself that suggests the O&M costs are closer to $70 per kW per year. This large increase is due to costs that were previously masked by the warranty and a small experience database in North America. The GLGH report suggests that for a small-scale wind farm, O&M is $86 per kW per year, while for large-scale wind farm, the value is $62 per kW per year.

The project lead times would be approximately three to four years, depending on the size of the project. Before a turbine purchase order is made, the environmental assessment study, permitting, interconnection studies, resource assessment and land lease agreements typically take two to three years. The larger project developers have volume purchase agreements with the major equipment suppliers, which can result in significantly reduced project turnaround time after the permitting phase.

Equipment lead times, depending on the size of the project, would be approximately one year, during which time mechanical, civil and electrical balance of plant is usually completed. Turbines can be erected quickly after the foundations are poured and cured, typically in parallel, taking two to three weeks each, including commissioning. A wind development typically has an accounting life of 20 years.

4.2.3. Ocean Power

How is electricity generated using ocean power?
Ocean power is a form of hydropower that converts the energy of tides or waves, into electricity or other useful forms of power.

Tidal stream turbines draw energy from water currents in a way similar to how wind turbines draw energy from wind. The higher density of water (which is 800 times the density of air) means that a single generator can provide significant power at low tidal flow velocities (compared with wind speed).

Wave power captures the movement of waves using devices such as buoy-like structures that convert wave motion to mechanical energy, which is then converted into electricity and transmitted to shore over a submerged transmission line.

4.2.3.1. Tidal Stream

Tidal currents are water flow motions caused by the rise and fall of tides, salinity, thermal and underwater topography. The kinetic energy of the currents can be transformed into electricity by the use of horizontal or vertical axis hydrokinetic turbines. This method is gaining in popularity because of the lower cost, and of lower ecological impact when compared to tidal barrages.

A 50 MW tidal stream development in the Bay of Fundy area on a single site was considered for this IRP.

Some of the hydrokinetic technologies being developed and studied today are shown below.

In November 2009, NS Power and its tidal technology partner, OpenHydro, successfully deployed its first commercial-scale, in-stream tidal turbine in the Bay of Fundy. The 1 MW turbine is shown in Figure 37.

Figure 37: In-stream tidal turbine used in Nova Scotia

There are at least three commercial-scale tidal power projects operating in the world (including a 20 MW plant in Nova Scotia), and these are all barrage plants. However, the kinetic energy of the marine currents can also be transformed into electricity by the use of horizontal or vertical axis hydrokinetic turbines.

Several turbine types are currently being tested. They include:

Axial Turbines – bottom mounted (anchored) or semi-submerged floating cable tethered.

Similar in concept to windmills operating under the sea. This type of turbine has the most prototypes currently operating, as well as a few commercial-scale applications. Their rated power typically ranges from 300 kW to 1.2 MW per turbine. This design is most used in the UK and the United States.

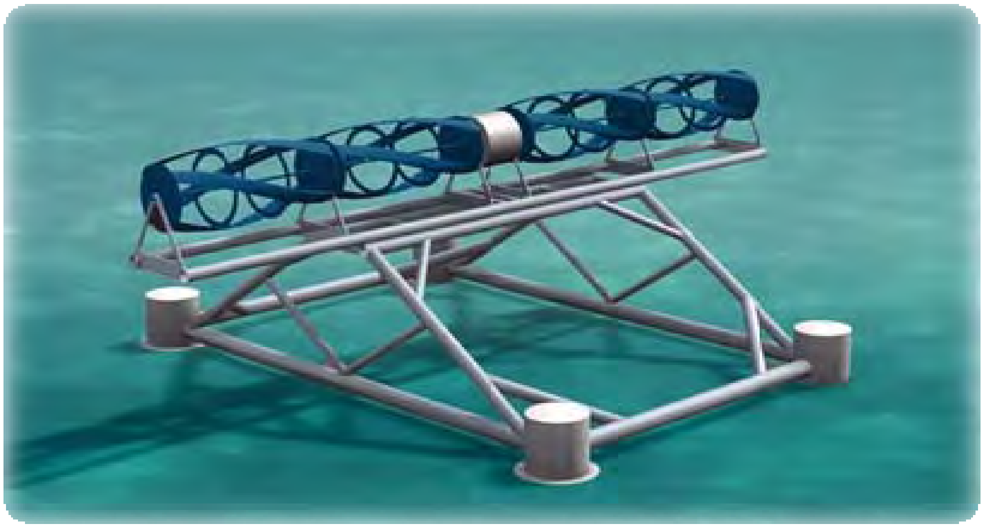
Figure 38: Typical bottom mounted axial tidal stream turbine

[Norwegian Environment Technology Center]

Axis Crossflow Turbines

This design is similar to standard hydropower crossflow turbines, but installed on the seabed. These turbines can be deployed either vertically or horizontally. They feature a helical blade design. Some projects using crossflow tidal turbines are being commercially piloted on a large scale in South Korea.

Figure 39: Typical crossflow tidal stream turbine

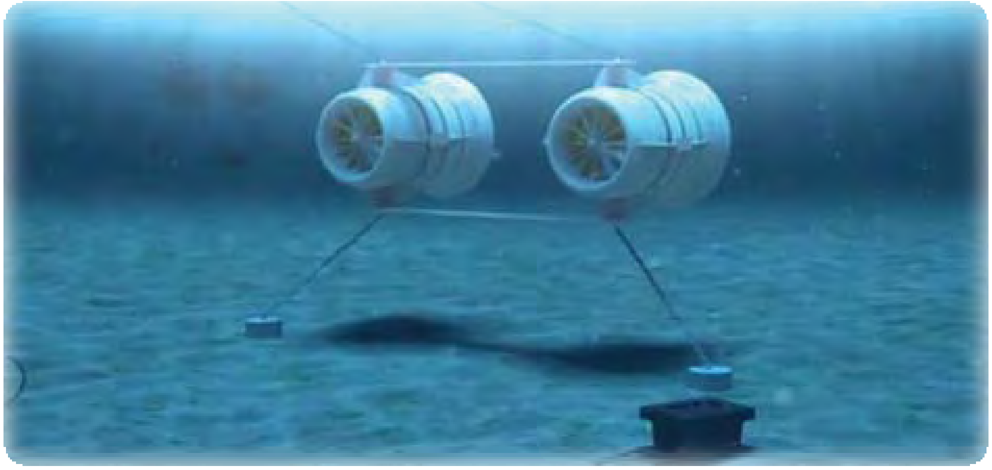


[Subsea World News]

Flow Augmented Turbines

This type uses flow augmentation measures, such as ducts or shrouds, which increase the incident power available to a turbine relative to the two previous types (axial and crossflow). Australian companies have performed successful commercial trials for this type of turbine.

Figure 40: Typical flow augmented semi-submerged floating tethered stream turbine

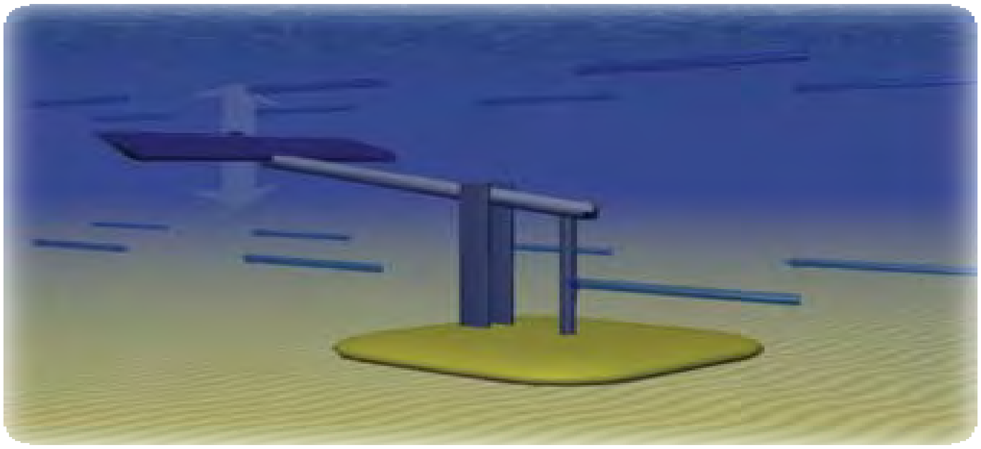


[hight3ch.com]

Oscillating Devices

These apparatuses do not have rotating components; rather, they make use of aerofoil sections that are pushed sideways by the flow. The motion is then used to power a hydraulic motor, which then turns a generator. European companies should shortly commission commercial-scale applications for this type of turbine.

Figure 41: Example of tidal oscillating device



[Engineering and Technology Magazine]

Tidal stream generators are new technologies and are not commercially mature. As such, none of the above-mentioned turbine types have either become standard or emerged as the clear leader. Very few applications have been implemented on a commercial scale. Several prototypes have shown promise, with many companies making bold claims, some of which are yet to be independently verified. However, they have not operated commercially for extended periods to establish performance benchmarks and reliable information on rates of return on investment. Nonetheless, this method is gaining in popularity because of the lower cost and lower ecological impact when compared to tidal barrages.

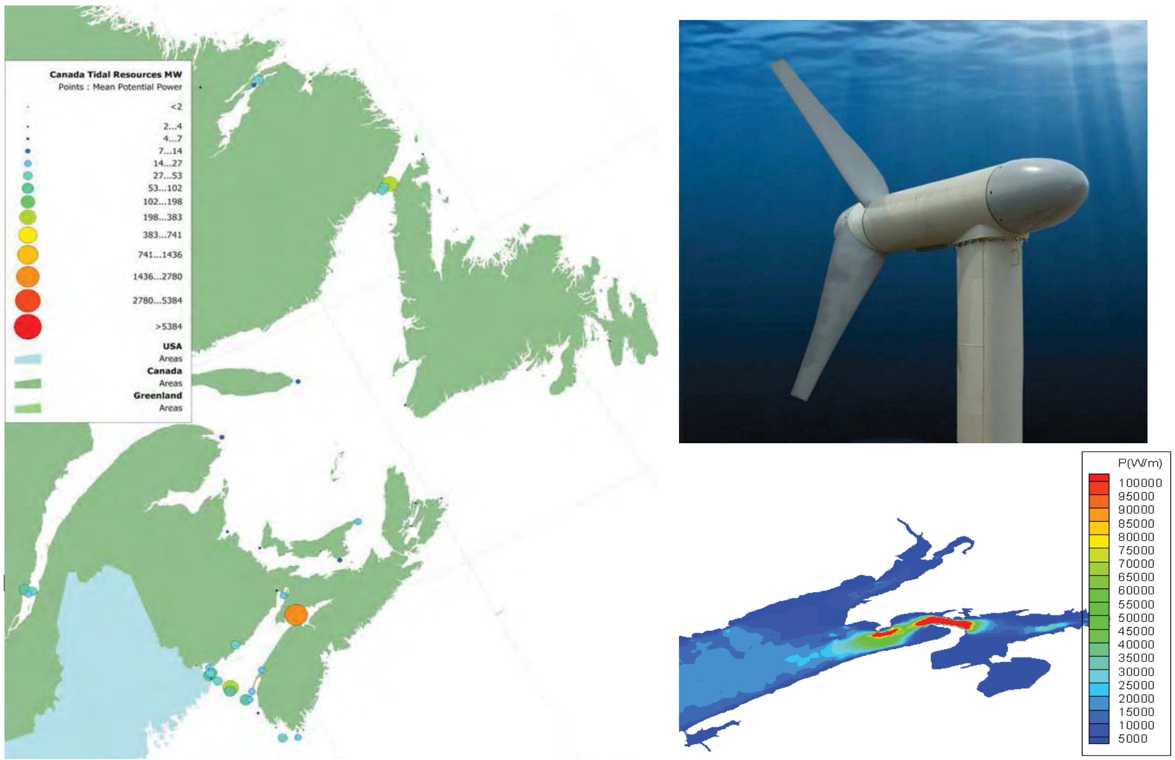
In New Brunswick, the estimated tidal energy resource is about 5.5 GWh per year, and exceeds 23.5 TWh per year if the resource in the Bay of Fundy is co-developed with Nova Scotia (see [Triton 2006][29]). However, extracting the entire power potential of the Bay could have significant environmental effects [McMillan & Lickley 2008][30].

Nova Scotia has started the procurement process for commercial-scale tidal stream schemes to be implemented in or along the Bay of Fundy. This activity could provide information on the costs and performance of tidal stream power that could be of interest to New Brunswick.

[29] http://www.marinerenewables.ca/wp-content/uploads/2012/11/Canada-Ocean-Energy-Atlas-Phase-1-Potential-Tidal-Current-Energy-Resources-Analysis-Background.pdf
[30] https://www.siam.org/students/siuro/vol1issue1/S01006.pdf

For this study, a 50 MW tidal stream development in the Bay of Fundy area on a single site is considered.

Figure 42: Left: Potential Tidal Current Resource Sites; Top Right: Typical Horizontal-Axis Kinetic Turbine; Bottom Right: Tidal Power Density in the Bay of Fundy (W/m)



Although turbine performances are important, what really distinguishes one application and technology from the others is the support/anchoring system. This component has a significant impact on capital expenditures (CAPEX) and operating expenditures (OPEX).

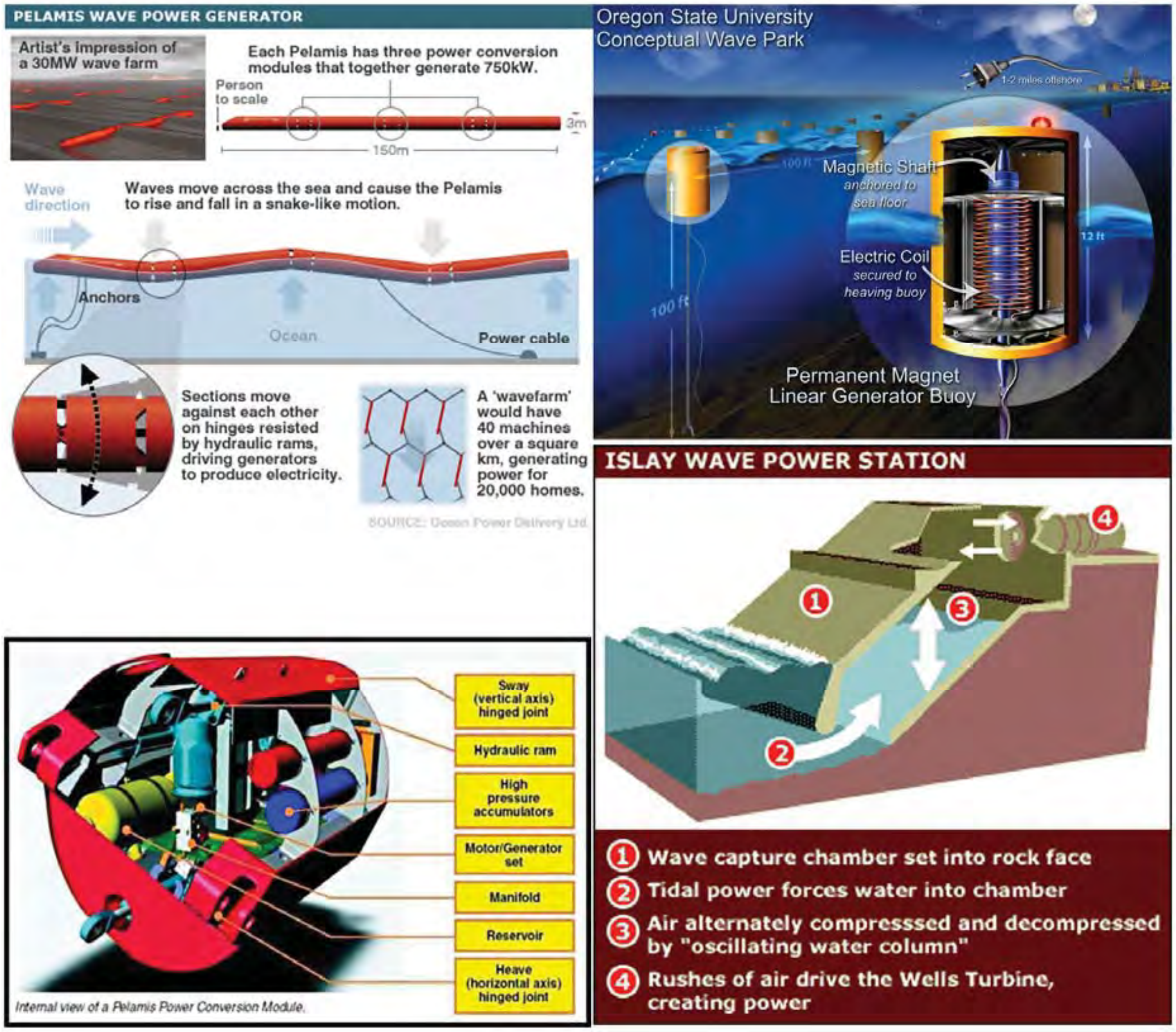
4.2.3.2. Wave

Devices that extract energy from ocean waves generally fall into two classes:

- near-shore devices that are rigidly mounted to the sea bottom or a rocky shore; and
- offshore devices that incorporate one or more semi-buoyant or floating oscillating bodies.

It has been suggested that the best wave power resource is offshore, due to the increased kinetic energy potential in waves offshore.

Figure 43: Typical wave power resource options



This study estimated the cost for a 10 MW wave power plant based on a surface-following system (shown in the leftmost part of Figure 43) that is an offshore device. The project location was assumed to be somewhere north of the Northumberland Strait, and the study based on the quality of the wind resource in the area (wave energy harvest is partly a function of surface wind speeds).

In a surface-following system, wave motion pressurizes hydraulic oil, and the pressure energy is subsequently converted into power through a specially designed hydraulic gear motor (in reverse).

Capital costs were based on scaling up a 2.25 MW wave power reference project located near Aguçadoura, Portugal. The wave energy converters in this project were located about 5 km off the Atlantic coast. Costs were based on 14 modules of 750 kW each and included the construction of a quayside facility for maintenance.

A significant project feature is the unit weight, which is approximately 1 tonne per kW covering sand ballast, floating vessels and hydraulic oils. Each module is approximately 750 tonnes. The hydraulic oils in the system are biodegradable; therefore, outside containment systems would not be required.

The cost estimate range for a wave power project is estimated to be -25 per cent to +75 per cent (relative to the baseline). As harvesting wave energy is technology specific, each technology has its own method of energy harvest, site-specific features and costs. All are considered “pre-commercial” at this time.

The O&M costs for wave power devices vary widely depending mainly on the technology, distance to the shore and wave intensity. However, the operation costs would be lower than for tidal devices because no divers would be required for inspection and maintenance operations. During maintenance, the surface-following devices are disconnected from their cabling and transported to a quayside facility. Typically, the wave power devices are modularized in order to allow quick removal and replacement operations without the need for large cranes or boats.

The project lead time for a surface-following wave converter would be approximately 12 to 18 months, depending on the capacity of the plant. The modules are commissioned separately on quayside, assembled, and then towed to site, where a final test is carried out. This process would take four to six weeks. This wave power plant would have an expected accounting life of at least 20 years; however, there is no proof of this with current technologies. Again, these figures depend greatly on the technology, tidal environment and operation conditions to which the devices are exposed, as well as on the maintenance schedule.

4.2.4. Combined Heat and Power

4.2.4.1. Biomass

How is electricity generated using biomass?
Biomass is defined as organic material derived directly from plants. It is produced through photosynthesis, the process used by plants to convert the sun's energy into chemical energy. This chemical energy can then be extracted from the biomass through combustion, to produce energy that can be used as heat or power. The optimum biomass option is a cogeneration option of steam and energy.

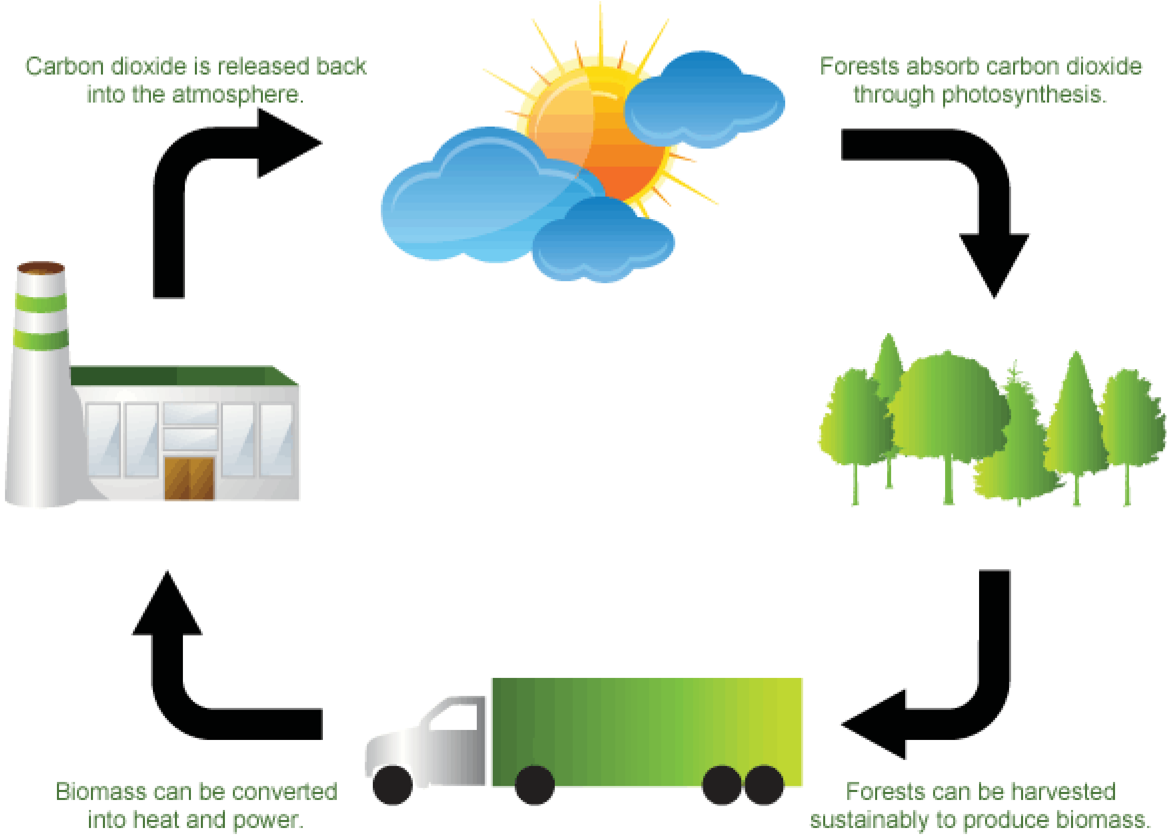
This generation option consists of a direct-fired biomass, combined heat and power (CHP) plant, with a net electrical output of 10 MW, and having the potential to supply a thermal output of 17 MW to an adjacent steam host. The plant would include a stoker grate boiler, a baghouse and a condensing steam turbine generator with a controlled extraction for the process steam supply. The condenser cooling system would include a multi-cell mechanical draft cooling tower.

The biomass stream was assumed to be wood waste with a gross calorific heating value of 6,800 Btu per lb. (15,788 kJ per kg) and a moisture content of 50 per cent. It was assumed that the wood waste would be sourced locally and delivered to the site via trucks with live bottom trailers. The site would include a wood handling and preparation area (screen and hogger). The plant configuration assumed a non-reheat rankine cycle with modest feedwater heating cycle and moderate main steam conditions (750 psig / 750 F).

In non-cogen mode (no steam host), the plant capacity would increase to 14 MW. Since this study did not identify a steam host, it was initially assumed that a non-cogen option would be evaluated. This would also provide the ranking of this supply option assuming electricity generation only. The economics would improve with consideration of a steam host as this would improve the thermal efficiencies of the system.

Biomass energy does not contribute to climate change in the way that energy derived from fossil fuels such as coal, oil and natural gas does. The carbon, which is stored in biomass material as it grows, is already part of the atmosphere. Biomass energy does not add new carbon to the active carbon cycle, unlike fossil fuels, which remove carbon from geologic storage. The carbon emissions from biomass facilities would have otherwise been released back into the atmosphere through some other fate or mechanism such as natural decay or an alternative disposal method like open burning. The advanced emissions controls on a biomass energy facility significantly reduce the amount of CO_2 released into the atmosphere along with other emissions such as particulate matter.

Figure 44: Process for biomass



Biomass energy is considered a "zero-greenhouse-gas-emitting technology" by the Regional Greenhouse Gas Initiative RGGI in the Northeast U.S. and the EU Emission Trading Scheme (EU ETS).

The total project costs were estimated based on a factored cost methodology using Hatch in-house data and recent vendor quotes for wood-fired boilers.

The operational costs for this facility include operations and maintenance personnel, and management and administrative staff. For a plant of this size, 20 employees would be the minimum requirement for management, operations and maintenance staff.

The lead time for a project of this size would range from 30 to 36 months from the start of engineering to the commercial operation date. Permitting activities were not included in the above durations. The biomass plant would have an accounting life of 25 years.

4.2.4.2. Fuel Cells

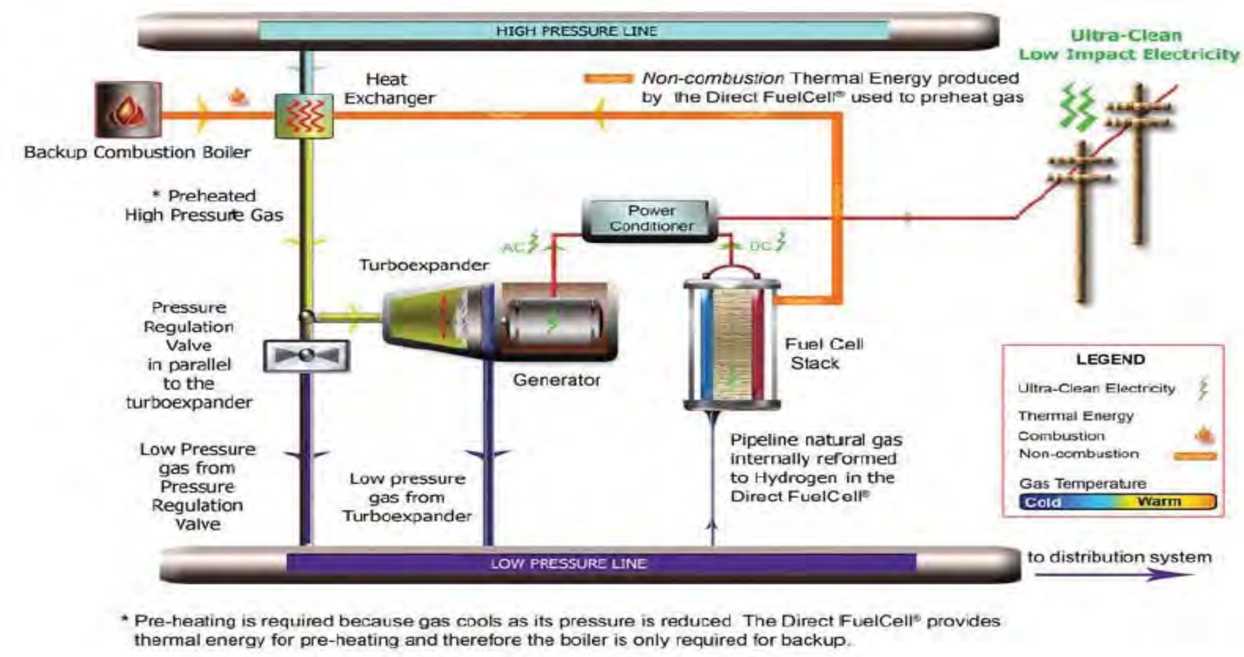
How is electricity generated using fuel cells?
Fuel cells work by catalysis, separating electrons and protons of the supply fuel, and forcing the electrons to travel through a circuit, hence converting them to electrical power. The waste produced from this process is typically simple compounds such as water and carbon dioxide. Fuel cells are different from conventional electrochemical cell batteries in that they use an external fuel such as natural gas or hydrogen.

Stationary fuel cells are typically installed in institutional and industrial facilities that can internally consume the power and heat generated. They are a combined heat and power technology with electrical conversion efficiencies exceeding 40 per cent. The heat load can be space or process heat, or heat to drive absorption chillers.

The construction of the Maritimes and Northeast Pipeline in 1999 provided end users in New Brunswick who were planning an upgrade of their utility plants with the option of using natural gas, which is also the feedstock for the two leading commercial fuel cell technologies on the market today. Fuel cells have also been installed in sewage treatment plants (running on digester gas), and have been installed as backup power in data and telecommunications centres.

Figure 45 illustrates a fuel cell being installed to generate power and heat in a gas letdown station in which gas pressures are recovered by the pressure reduction from mainline levels to distribution levels.

Figure 45: Fuel cell application



Capital costs for a 1 MW plant were estimated for this study. Costs were based on the supply of 4 x 250 kW fuel cell modules utilizing molten carbonate fuel cell technology (MCFC) by Fuel Cell Energy. The other commercial technology for utility scale plants is UTC Power's phosphoric acid fuel cell (PAFC). A 1 MW plant based on PAFC technology would consist of five UTC Power PureCell 200 modules.

One benefit of PAFC over MCFC is that the former does not require a continuous stream of water for the process (which also requires demineralization).

It was assumed that natural gas would be available at adequate pressures (<0.1 bar (g)) to support operation at base load under all site-ambient conditions without on-site gas booster compressors.

There are a number of factors that affect the capital cost estimate accuracy. These include equipment costs, as well as costs associated with interfacing with the heat distribution and electrical systems at a host site. Fuel quality and the amount of fuel conditioning can also vary from location to location on a continental basis, but within New Brunswick would need nearly the same requirements throughout (the exact details of these requirements were not determined in this study).

For this cost and technology review, the MCFC was selected due to:

- higher power production efficiencies (lower heat rate);
- higher temperature waste gas, of the order of 370°C (can be used in a wider variety of heating applications);
- lower estimated capital costs. In addition, UTC's PAFC costs have remained the same (per kW) or have been trending upwards over the last decade; and
- Canadian application experience (Enbridge).

Fuel cell plants in general require little or no site work due to their relatively small footprint. Most installations in the 200 kW to 1 MW range are located in the yard or parking area of an end-user's site or are installed on rooftops. Fuel cells located indoors require additional ventilation considerations (not assumed in the cost profile). Auxiliary costs for all fuel cell types include a heat recovery unit and piping (to/from a heat sink), and a small nitrogen facility (bottles or liquid form – for start-up, and desulphurization catalyst change-out). Fuel cells cannot "black start" and require utility power feeds or a diesel generator to start them up.

Fuel cells require about three days to warm up and are normally kept on warm standby when their power production is turned down. During start-up, the fuel cell is back-fed power from the utility (about 50 kW). Fuel cell plants typically run unattended. Water treating reagents associated with the molten carbonate technology require periodic refilling and system monitoring. Fuel cell vendors offer service agreements that include remote monitoring.

The other plant consumables are catalysts for desulphurization and Carbon monoxide (CO) shift (part of the reforming operation); these require replacement every three years or so, depending on the sulphur content of the fuel and on utilization.

Project lead time would be approximately 9 to 12 months after receipt of order. Including up-front studies and preliminary engineering, project implementation would take approximately two years. To date, one utility-scale project has been implemented in Canada by FuelCell Energy. From a project implementation perspective, this means that issues related to Canadian codes and standards have been overcome (the product in this case is FCE's 1500 series, 1.4 MW fuel cell in an application that recovers pressure energy from gas pipelines developed in alliance with Enbridge – shown in Figure 45). Construction and commissioning would take approximately two months.

The main capital replacement issue over the project's lifecycle is the replacement of the fuel cell stack (the membrane) every five years, at a cost of about one-third of the original equipment cost.

This fuel cell plant would have an accounting life of approximately 20 years. Of the commercial plant profiles reviewed (those 200 kW or above), the longest-in-service was approximately 10 years. Steam reformer lifecycles routinely exceed 20 years (with periodic catalyst and reformer tube changes), as there are relatively few moving parts.

As mentioned above, the stack replacement is a major project lifecycle issue and has been addressed somewhat by UTC Power with their recent launch (late 2008) of their 400 kW model, which has a projected stack life of 10 years, compared to Fuel Cell Energy's five years (which formed the basis of the costs in this review). UTC Power does not have any Canadian fuel cell installations.

Figure 46: Fuel Cell installation at a brewery, 4 x 250 kW modules, from FuelCell Energy

4.2.4.3. Microturbines

How is electricity generated using microturbines?
A microturbine is a small version of a combustion turbine. An air/gas mix is ignited in a combustion chamber and the resulting gas flow is directed to the blades of a turbine which turn a shaft. The rotating shaft is connected to an electrical generator which converts the rotating shaft motion into electrical energy.

Microturbines are used in niche applications where CHP is required, and are used mainly as distributed generation (DG) resources. The generation option considered in this study is a nominal 1 MW natural gas fired micro-turbine based. Several installations could be considered in communities or businesses where natural gas is available.

Packaged microturbines are typically considered to be in the range of 60 to 500 kW and are available from a number of manufacturers including Allied Signal Power Systems, Bowman Power Systems, Capstone Turbine, Elliot Energy Systems, NREC (Ingersoll-Rand) and Turbec (Volvo/ABB). For this study, the plant is assumed to consist of 5 x 200 kW units as manufactured by Capstone. This manufacturer is prominent in the microturbine field. It offers a standard package consisting of five C200 models.

Figure 47: A typical microturbine

The system would be capable of operating in grid-connected mode and in islanded mode. The microturbine, with its low emissions, low maintenance requirements and high reliability, is well suited for combination peak-shaving and standby power applications as well as small-scale combined heat and power plants. Site average performance was estimated based on an elevation of 8 m AMSL and annual average temperature of 5.5ºC.

Post-combustion emissions controls were not included (i.e., CO catalyst or NO_x catalyst) as many microturbines emit less than nine ppm of NO_x (ref.15 per cent O_2) (<0.49 lb. per MWh) at full load.

It was assumed that pipeline gas would be available at adequate pressure (6 bar (g)) to support combustion turbine operation at base load without on-site gas booster compressors.

The overnight total project costs were estimated based on a factored cost methodology using Hatch in-house data and recent vendor quotes for the major equipment.

Non-fuel variable O&M costs were estimated from EPRI technical reports. The costs were based on comprehensive maintenance packages being offered by microturbine packagers, and include all parts and labour.

The project lead time would be two years. This microturbine plant would have an accounting life of 25 years.

4.2.5. Biomass Bubbling Fluidized Bed

How is electricity generated using biomass bubbling fluidized bed?
Fluidized beds suspend solid fuels such as biomass on upward-blowing jets of air during the combustion process. The result is a turbulent mixing of gas and solids. The tumbling action, much like a bubbling fluid, provides more effective chemical reactions and heat transfer. The heat produces steam that drives a steam turbine connected to a generator, which then produces electricity.

This generation option is for a nominal 50 MW biomass bubbling fluidized bed (BFB) thermal power plant. The reference plant would be a one-on-one arrangement based on one boiler with bubbling fluid bed combustion technology and one condensing steam turbine generator. The facility would process approximately 2000 tonnes per day of wood.

The plant location is assumed to be a green field site on the seacoast with an elevation of six to eight metres above sea level. The plant would employ a once-through seawater cooling system. The fuel for the plant is assumed to be wood with a maximum moisture content of 50 per cent and a heating value of 6,800 Btu per lb. (15,788 kJ per Kg) (HHV). It is assumed that the wood waste is sourced locally and delivered to the site via trucks with live bottom trailers. The site includes a wood handling and preparation area (screen and hogger).

The BFB combustion process and control results in low NO_x and CO. Sulphur emissions are managed by utilizing low-sulphur biomass feedstock. It is not anticipated that post-combustion emissions controls would be required and these are not included.

The total project costs were estimated based on a factored cost methodology using in-house data for recent projects. The cost estimate reflects an EPCM contract strategy. The total project cost does not include owner's costs.

The cost of the plant includes one (1) BFB boiler, one (1) steam turbine generator, and all auxiliary and ancillary equipment required for the thermal cycle. The scope also includes a generator step-up transformer; a switchyard; a water treatment plant; biomass handling equipment from the truck unloading point to the boiler house, including a biomass stockyard, stacker and reclaim system; light and heavy oil fuel systems for ignition and warm-up, including storage; and office and maintenance facilities.

Hatch has made the following assumptions:

- power from the power distribution grid will be available to start the plant;
- the plant will have access to deep seawater requiring a short cooling water intake and outfall;
- biomass will be delivered by truck;
- fresh water will be available to the plant for cycle make-up and other water needs; and
- oil fuel will be supplied by truck.

Figure 48: 50 MW biomass bubbling fluidized bed plant located in France

4.2.6. Municipal Solid Waste

How is electricity generated using municipal solid waste?
Waste-to-energy plants burn municipal solid waste (MSW) to generate electricity or heat. At the plant, MSW is unloaded from collection trucks and shredded or processed to ease handling. The waste is fed into a combustion chamber to be burned. The heat released from burning the MSW is used to produce steam, which turns a turbine to generate electricity.

This generation option is for a nominal 50 MW municipal solid waste thermal power plant. The reference plant would be a three-on-one arrangement based on three refuse boilers and one condensing steam turbine generator. The facility would process approximately 2,000 tonnes of waste per day.

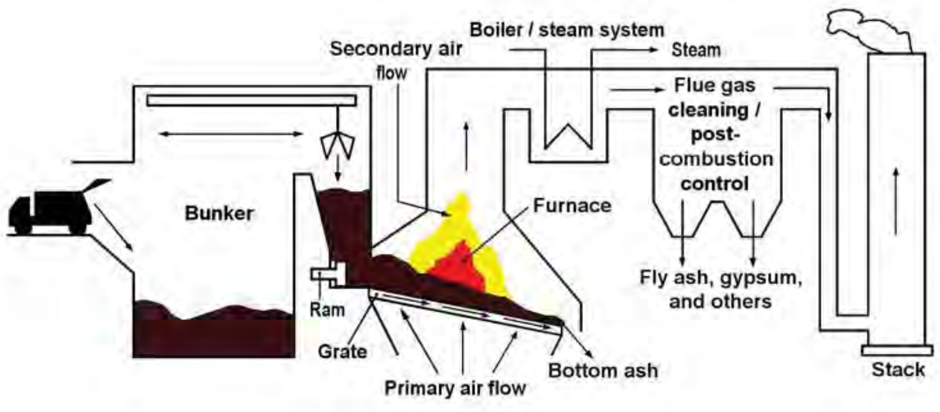
The plant location is assumed to be a green field site on the seacoast with an elevation of 6 to 8 meters above sea level. The plant would employ a once-through seawater cooling system. The waste for the plant is assumed to have a heating value of 5,300 Btu per lb. (12,305 kJ per Kg).

The cost of the plant includes three MSW boilers, one steam turbine generator, and all auxiliary and ancillary equipment required for the thermal cycle. The scope also includes a generator step-up transformer; a switchyard; a water treatment plant; waste handling equipment from truck to boiler house, light and heavy oil fuel systems for ignition and warm-up, including storage; and office and maintenance facilities.

Assumptions:

- power from the power distribution grid will be available to start the plant;
- the plant will have access to deep seawater requiring a short cooling water intake and outfall;
- waste will be delivered by truck and unloading provisions have been included;
- fresh water will be available to the plant for cycle make-up and other water needs; and
- oil fuel will be supplied by truck.

Figure 49: MSW combustion plant



4.2.7. Solar Photovoltaic

How is electricity generated using solar energy?
Solar energy can take the form of photovoltaic or thermal energy. Incident solar radiation (sometimes called "insolation" for short) can be converted into electricity directly, using photovoltaic (PV) cells.

Solar irradiance consists of direct radiation (between the sun and the point of interest), and diffuse radiation, which is received from all directions after being scattered by the atmosphere, or redirected by a cloud cover. The total irradiance varies as a function of time throughout the day (peaking at midday), and varies seasonally, with the angle of the sun in the sky peaking at the summer solstice. In addition to the daily and seasonal variability, the energy source is also intermittent, primarily as a function of air mass and cloud cover. Figure 50 shows New Brunswick's average annual daily photovoltaic potential. Figure 51 summarizes the average solar resource available for a typical year in three cities in New Brunswick. Data for the chart and table was gathered from Natural Resources Canada.

Figure 50: New Brunswick's photovoltaic potential

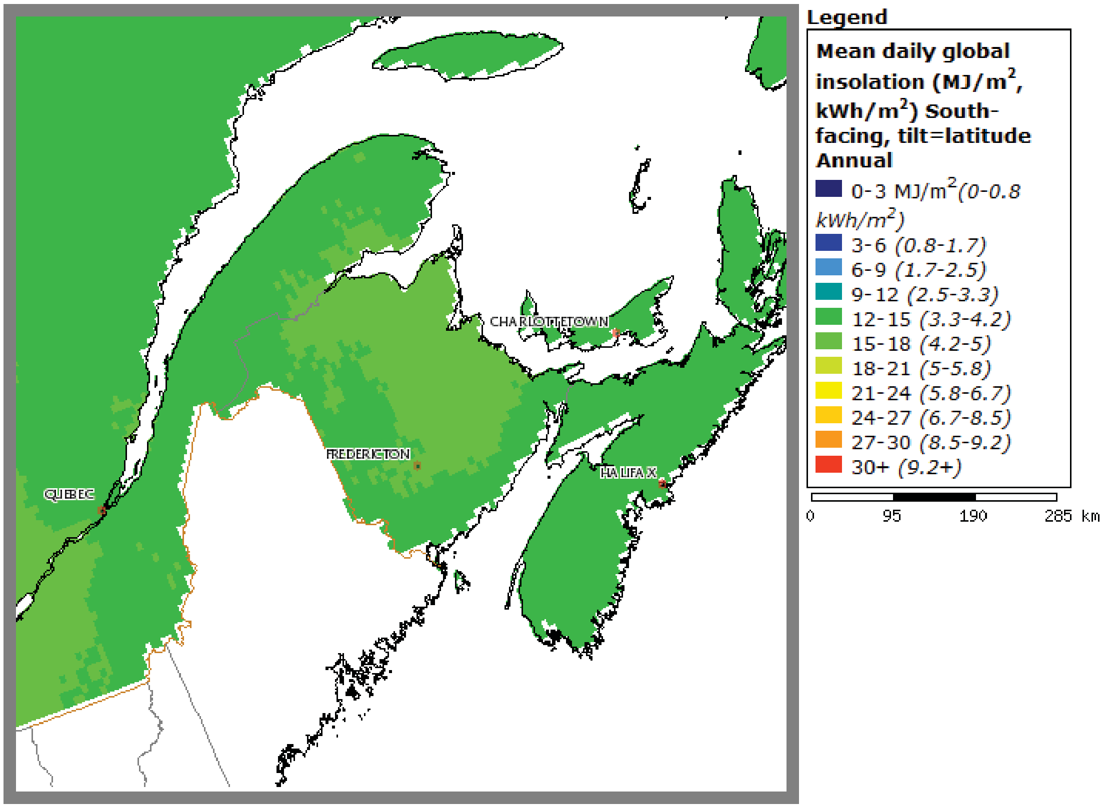


Figure 51: Photovoltaic potential in three cities in New Brunswick

City	South-facing Tilt = Latitude Solar Resource
Fredericton	1,530 kWh/m^2/year
Saint John	1,510 kWh/m^2/year
Miramichi	1,550 kWh/m^2/year

Incident solar radiation can be converted into electricity directly (using photovoltaic (PV) cells) or indirectly (first converting the radiant energy to mechanical energy by thermal means).

PV panels (or "modules") are capable of converting both types of incident radiation to electricity, and can therefore produce electricity even during periods dominated by diffuse radiation (cloud-covered skies). PV modules use a silicon semi-conductor material to directly convert solar radiation to direct current (DC) electricity. The most common implementation of solar cell technology is the grouping of monocrystalline or polycrystalline cells to create panels. A panel is typically composed of 60 or 72 cells, mounted to a glass surface using an epoxy, then laminated with a plastic backing material. Monocrystalline is the most mature of the photovoltaic technologies. The cells are created from single crystals sliced into wafers and are the most expensive and the most efficient, achieving module efficiencies up to 20 per cent. Monocrystalline panels are often in applications where space constraints exist such as rooftop installations. Polycrystalline cells are comprised of multiple crystalline structures created by melting silicon in a mold and then creating wafer slices. They can achieve efficiencies up to 16 per cent and are less expensive than monocrystalline. Polycrystalline panels are often used in larger solar facilities that are less space-constrained.

PV panels can also use thin film solar cell technology, which do not use cells, but consist of applying the semiconductor material directly to a glass substrate. The manufacturing process for thin film cells is less costly than that of crystalline cells; however, thin film panels are less efficient, with efficiencies ranging up to 12 per cent. Thin film modules also perform better in high temperature and low-irradiance sites than polycrystalline or monocrystalline panels.

PV power plants consist of PV modules wired together in series to make up a string, with strings connected in parallel to comprise a solar array. The parallel strings direct the DC electricity produced by the cells to an inverter that converts it to alternating current (AC) power, synchronized with the grid. Inverters include power electronics that continuously monitor and modify solar array voltage to maximize power production. Solar arrays can either be mounted on a fixed support structure at an angle selected to optimize annual production, or on a one or two-axis tracking system that follows the sun throughout the day. A tracking system increases the annual energy yield due to an increased aperture area, and decreased reflection losses that occur at high solar incidence angles; however, they increase the capital and operational costs, and are less effective in areas with high amounts of diffuse radiation.

Based on the solar resource available in New Brunswick, the current CAPEX analysis was based on a PV solar plant mounted on a fixed support structure, at an angle optimizing annual energy production.

Two plant sizes were considered in this study, 10 MW and 25 MW. These two plant sizes would generally both represent a large-scale PV plant. Although slight economies of scale would be realizable with the 25 MW plant, the capital costs would essentially be equal on a per kW installed basis.

Figure 52: A 12 MW PV facility located on cropland in Germany

For this study, the 10 MW site was based on polycrystalline solar cells, while the 25 MW site was based on thin film solar cells (for technology comparison purposes only). Polycrystalline cells typically demonstrate efficiencies between 13-16 per cent, and account for 55 per cent of the world market share. Thin-film cells typically demonstrate efficiencies between 5-11 per cent, and account for only 10 per cent of the world market share; however, they are less expensive per kilowatt, and constant research is being undertaken to improve efficiencies and lower costs further. The remaining world market share belongs to the more expensive monocrystalline cells, which demonstrate efficiencies between 15-18 per cent [GES 2008][31].

Theoretical efficiency of lab-made cells has been increasing, but the efficiencies of commercially available cells have not changed significantly over the last several years.

Cost estimates for the PV plants were mainly based on data available from recent projects constructed in Ontario, Canada. Ontario is the second-largest market for solar PV projects in North America, behind California, and therefore provides a good proxy for costs associated with building solar PV in Canada. However, the Ontario market is somewhat unique due to the requirements of the Feed-In Tariff program requiring equipment and services be sourced from

[31] "Planning and Installing Photovoltaic Systems", The German Energy Society, 2008

Ontario-based manufacturers. These costs were supplemented with other projects constructed recently in Canada, the United States, and South Africa to apply international equipment costs.

The cost estimates include everything from the onset of the engineering phase to connection of the plant to the grid. A summary of the assumptions used follows:

- PV plant is grid connected with no battery storage;
- 10 MW plant based on using polycrystalline solar panels;
- 25 MW plant based on using thin film solar panels; and
- The arrays are mounted on a fixed-tilt support structure.

Items excluded from the estimate are as follows:

- Cost of land. Land budgets range from 1.8 ha per MW for polycrystalline technology, to 2.8 ha per MW for thin film technology (includes maintenance space between arrays but not land that cannot be used due to site features such as drainage paths). Lands proposed for solar projects are typically deforested.
- Transmission line to point of interconnection (POI) and substation at POI. It should be noted that this can vary greatly, based on jurisdiction and grid capabilities. In Ontario, interconnections costs for projects built or under construction can range from $500,000 to more than $8,000,000.
- Geotechnical conditions unfavourable to the installation – the cost of installation of solar plant is in part dependent on the civil/geotechnical aspects of the site. The installations with lowest cost involve installation in soil that allows for driven pile construction. Sites with bedrock near the surface (that may need rock trenching), or unstable gravel soils that require caissons, can increase the cost of installation.

The cost of PV panels has fallen dramatically in the past five years. Industry analysts speculate that costs are currently unsustainably low and it is expected that the costs of the current generation of PV panel technology has stabilized. Price reductions continue to occur, however, with respect to balance of plant components such as inverters. Higher DC voltages have been proposed to decrease cable sizing and increasing efficiency of inverters.

The two main types of operation and maintenance costs (O&M) methodologies are usually labeled “preventative” and “reactive” maintenance. Preventative maintenance involves a regime of regularly scheduled activities including inspections, cleaning and minor repairs or equipment replacements. The goal of this methodology is to prevent issues before they occur and to minimize unscheduled visits, repairs and downtime. Reactive maintenance, on the other hand, relies heavily on detailed monitoring and fixing issues as they occur. This is sometimes referred to as the break-fix model. The goal of this strategy is to minimize maintenance cost by only repairing on an "as-needed" basis.

O&M costs can vary significantly between solar facilities depending on a variety of factors. One survey conducted by EPRI found total O&M costs to range from $6–$27 per kW per year [EPRI 2010][32]. For sites of the size described here, it is expected O&M cost to be around $15 per kW per year with an additional $5 per kW per year as part of a reserve for the expense of replacing the inverters every 10 years on an amortized basis, due to the shorter lifespan of the inverters. This reserve is the equivalent cost of purchasing inverters with 20-year warranties. This translates to $20 per kW per year for both solar facilities.

The typical development time frame, from concept to on-line date (lead time), is relatively short for PV power plants. Procurement and installation time varies with market conditions with a minimum of six months [OPA 2009][33]. Including the engineering phase, lead times of 18 to 24 months are estimated for the 10 MW and 25 MW projects respectively (not including environmental screening and utility connection studies).

The expected service life of the PV plant is estimated to be 30 years. Typically, solar panels have a 25-year limited warranty on power output, which includes 90% power output assurance for the first 10 years and 80% power output assurance for the remainder of the warranty period. It is expected that the panels will continue to operate with a reasonable power output for at least five years longer than the stated warranty.

While the overall service life of the plant is stated above, it is noteworthy that the inverters will typically wear out before the end of the service life and need to be replaced or overhauled, as previously stated. It is noted that this cost has already been accounted for in the operation expenses estimate.

4.2.8. Enhanced Geothermal

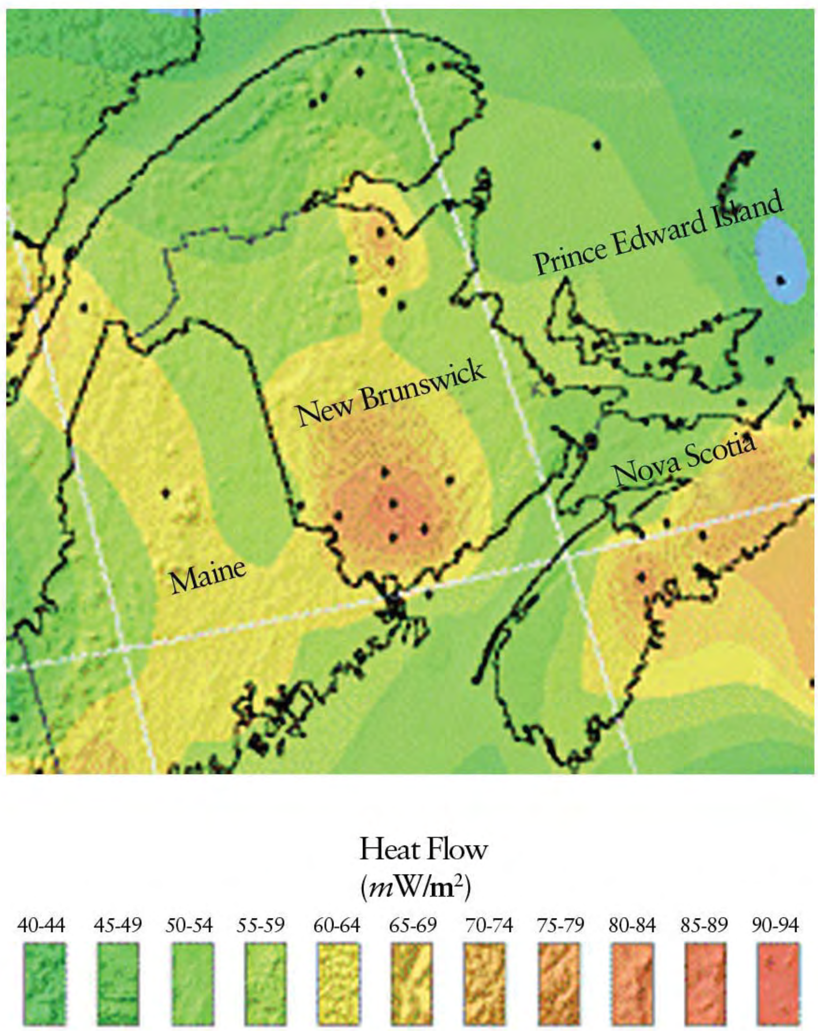
How is electricity generated using enhanced geothermal?
Enhanced geothermal systems inject cold water under high pressure into underground rock formations. This water travels through the fractured rock capturing heat until it becomes very hot and is forced to the surface through a second borehole. A steam turbine and generator can be used to convert the energy in the heated water to electricity.

Geothermal energy originates from natural heat in the earth that is trapped close enough to the surface to be extracted economically. This energy resource is considered renewable, sustainable and reliable over the long term. From the geothermal mapping of North America

[32] http://www.smartgridnews.com/artman/uploads/1/1021496AddressingPVOaMChallenges7-2010_1_.pdf
[33] http://www.woodstockhydro.com/pdf/StandardOfferProgram_IntroductoryGuide_Aug13_08.pdf

(American Association of Petroleum Geologists, Figure 53), New Brunswick has modest geothermal potential, particularly in the southwest near Fredericton and the northeast near Bathurst.

Figure 53: Enhanced geothermal potential in New Brunswick

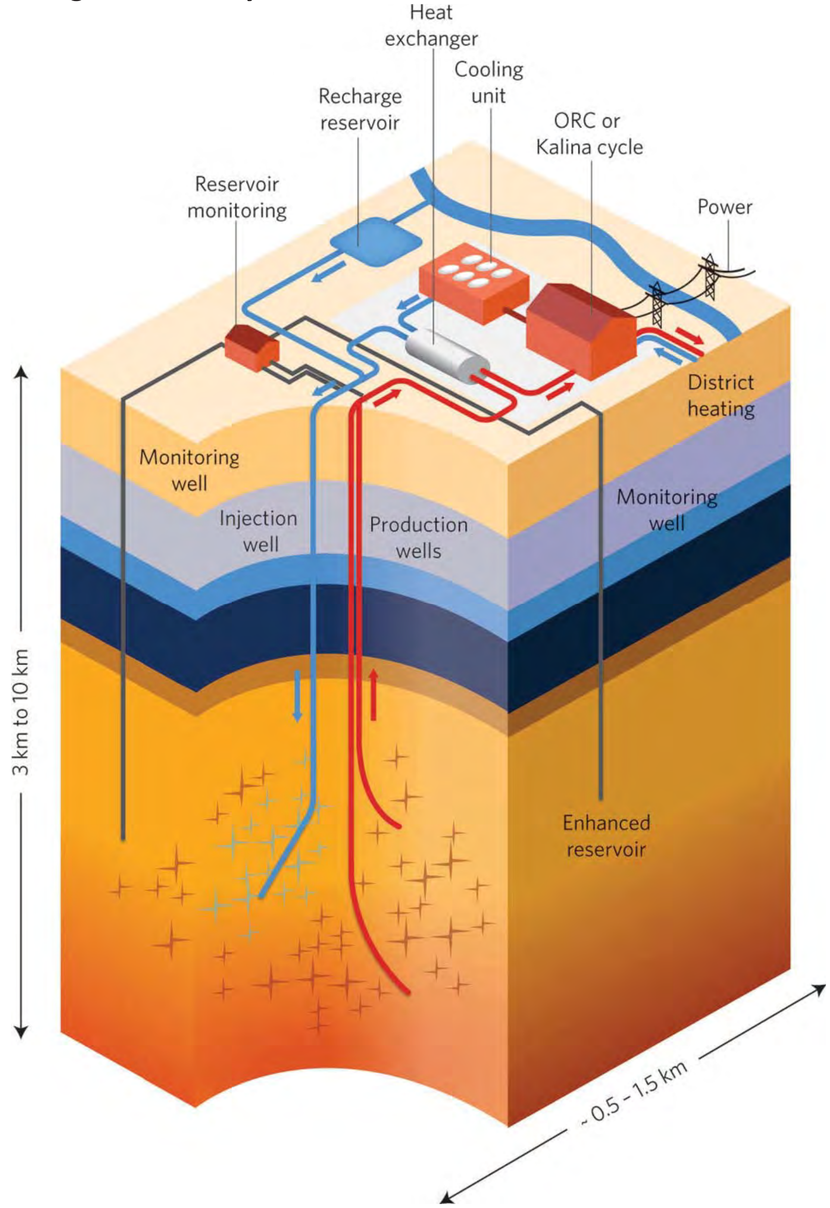


All of the commercial geothermal power plants are based on transferring geothermal water to the surface, where the heat energy is transferred into electricity at a geothermal power plant. There are four commercial types of geothermal power plants:

- flash power plants;
- dry steam power plants;
- binary power plants; and
- flash/binary combined power plants.

In addition to the above-mentioned technologies in use today, additional geothermal applications and technologies are being developed. The most commonly discussed method is Enhanced Geothermal Systems (EGS), as shown in Figure 54, which has the potential of dramatically expanding the use of geothermal energy. This method's concept is to extract heat by creating a subsurface fracture system to which water can be added through injection wells. Improving the natural permeability of rock will create an enhanced, or engineered, geothermal system. Injected water is heated by contact with the rock and returns to the surface through production wells, as in naturally occurring hydrothermal systems.

Figure 54: Enhanced geothermal system



For this project, the capital costs estimated for a 25 MW power plant were not based on a specific technology; rather, they were based on average costs provided by the Geothermal

Energy Association (GEA). To narrow down technology suitability for applications in New Brunswick, more information about the nature of the resource would be required. Nevertheless, the majority of a geothermal project's cost is the power plant (about two-thirds), due to the relatively low temperatures of the geothermal resource (in New Brunswick, estimated to be about 180 to 200°C at 6 km depth).

The costs of developing a geothermal power plant are comprised of exploration, resource confirmation and characterization (drilling and well testing), and site development (facility construction). These estimates were based on geothermal power plant construction in western US states.

A summary of the cost estimate assumptions are as follows:

- The costs of developing a geothermal power plant in GEA reports are average costs, regardless of technology;
- The cost estimates in the GEA report were based on developing a 50 MW power plant. Costs in this estimate were increased by 5 per cent on a per kW basis due to economies of scale;
- As the specific resources in New Brunswick have not been confirmed (greenfield project), the cost of exploration and drilling activities would be increased by 10 per cent; and
- Cooling water would be readily available.

Costs are estimated to range from -25 per cent to +50 per cent relative to a baseline cost. The cost range has three main contributing factors:

- the extent of exploration required to identify and harvest a geothermal resource;
- the costs associated with different harvest technologies (site specific); and
- the trade-offs associated with going deeper into the earth to obtain higher temperatures versus the power plant costs.

Maintenance costs encompass all expenses related to the maintenance of the power production equipment (generator and power plant), the collection system (field pipes) and vehicles.

The costs related to steam field renewal were also included and are discussed in more detail below.

Project lead time for most geothermal projects would be three to five years. A geothermal power plant would have an expected accounting life of at least 30 years.

It is important to note that some components would typically wear out before the end of the accounting life and would need to be replaced or overhauled. The most important components that require replacement in geothermal power plants are production and injection wells.

The well productivity decline is a complex phenomenon mainly explained by the pressure and/or temperature drop of the reservoir. Make-up drilling aims to compensate for the natural productivity decline of the project start-up wells by drilling additional production wells. This operation could be considered as the geothermal "fuel" cost. The annual maintenance and make-up drilling costs correspond to approximately 5 to 7 per cent of the initial drilling costs.

4.2.9. Pumped Hydro Storage

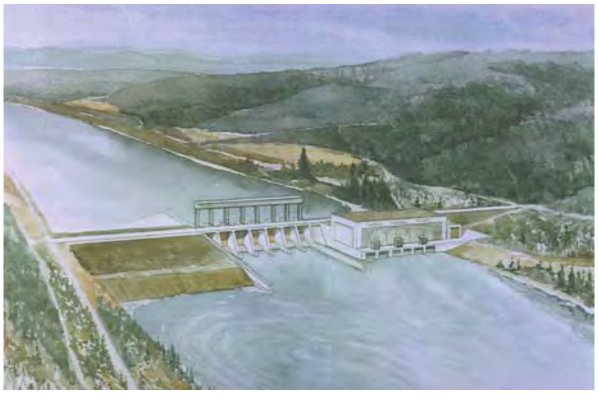
How is electricity generated using pumped hydro storage?
Pumped storage is a variation of hydroelectric power generation, which utilizes the difference between on and off peak electricity in the project's economic evaluation. Pumped storage uses low cost, overnight electricity to pump water from the tailwater pond back up into the reservoir; during the peak periods during the day, this water is then used to generate electricity that is sold at a higher price.

NB Power currently owns and operates seven hydro generating stations, one of which—the Grand Falls Generating Station—has been investigated as a potential site for pumped storage.[34] More recently, Hatch studied the addition of a new 100 MW powerhouse at the Station. For more information, refer to Section 4.1.3.1 (Grand Falls).

Figure 55: Artist's rendition of the pumped hydropower project at Grand Falls

[34] "Grand Falls – Morrell Integrated Pumped Storage Project", 1989, New Brunswick, Canada, Acres International P8472.

Figure 56: Artist's rendition of the Morrell Station to provide storage for pumping



For purposes of this study, the total costs for a 100 MW pumped storage plant were estimated. Costs from Grand Falls new supply study were used directly (base costs) and the incremental costs were estimated.

The incremental costs were based on installing pump-turbine equipment in the proposed new 100 MW powerhouse at Grand Falls (instead of turbines only) and adding a lower reservoir. All of the other new facilities (intake, penstock, surge tank and spillway) can be used as described in Section 4.1.3.1 (Grand Falls).

The lower reservoir is required to provide a sufficient volume of water for pumped storage operation during periods of low river flow. This could be accomplished by constructing a dam with spillway a suitable distance downstream of the Grand Falls facility and impounding the upstream water to create sufficient live storage. However, with this approach the difference between the level of the impoundment (elevation ~95 m) and the river (elevation ~90 m) would represent lost energy, even when Grand Falls was operating strictly in the "conventional hydro" mode. Construction of a separate low head hydro facility at the impounding dam would be necessary to recover this energy. An alternative would be to have a separate lower reservoir isolated from the river into which the pump-turbine could discharge during pumped storage operations. The pumped storage plant would also be designed to discharge (along with the conventional hydro units) directly into the river during periods of higher river flow.

Lower reservoir costs will vary with retention capacity. The lower reservoir can be constructed within the existing river ("split" river arrangement), next to the river and close to the plant, or some variation in between. Hatch estimates that for every hour of live storage, approximately 1.25 million m^3 is required assuming zero natural river inflow; at 6.6 m depth, that's 189,000 m^2). This study did not assess if this was feasible; it only presents the idea as an alternative to the Grand Falls/Morrell Integrated Development concept where the lower reservoir consisted of the entire river from Grand Falls to Morrell, and was raised by approximately 4 m at the Grand Falls tailrace, resulting in a head loss of 10 MW at the existing Grand Falls Generating Station.

For pumped storage plants, the costs of reservoirs are site specific; in other recent pumped storage studies, costs were \$2 to \$10 per m^3 live storage. Assuming \$8 per m^3, the cost of the reservoir with four hours live storage would be \$40 million.

The other element of incremental cost, compared to the 100 MW addition at Grand Falls, was the increase in capital cost for the powerhouse to allow for:

- the physically larger pump-turbine machinery (as compared to a conventional turbine);
- motor starting equipment and reversing switches, etc.;
- the civil costs for the slightly larger powerhouse, which has a deeper setting to accommodate the increased submergence requirements for pumping operation; and
- facilities to allow the pump-turbine to discharge either to the river or the reservoir.

The cost increase is estimated to be approximately 40 per cent of the total powerhouse costs of the base powerhouse. The cost increments for the added pumped storage features range between -25 per cent and +65 per cent.

O&M costs for investor owned hydroelectric facilities in the U.S. (including pumped storage facilities) average \$13.40 per kW [EIA 2010][35]. Adjusted to 2013 price levels, the cost is \$14.60 per kW. Translating this to the Grand Falls proposal with its mix of conventional hydro and pumped storage, the O&M costs are approximately \$1.5 million. For this study, approximately 20 per cent of this cost can be charged to the pumped storage addition to the base project, or \$300,000, or \$3.00 per kW.

Operating costs also include the cost of electricity for pumping, based on market prices (similar in concept to “fuel” costs). Energy consumption is estimated at 58.4 GWh per year (75 per cent cycle efficiency, 5 per cent capacity factor basis).

Front-end studies and permitting would take approximately three years, and the reservoir itself would take another two to three years, depending on retention volume. The base plant has a construction period estimated at 30 months from mobilization.

Hydro and pumped storage stations have similar lifecycles with the exception of the pump turbine, which typically has a slightly decreased life span relative to conventional hydro due to its nature of operation (increased wear on bearings, bushings and seals). The anticipated design life of a pumped storage hydro facility varies from 40 to 70 years; the service life of the pump turbine is anticipated to be 60 years, with major refurbishment every 20 years.

[35] http://www.eia.gov/oiaf/beck_plantcosts/pdf/updatedplantcosts.pdf

Capital refurbishment costs can range between 30 to 50 per cent of the original cost of the hydraulic machinery in a major renewal. Given these rules of thumb, the capital renewal portion of OPEX costs are estimated to be $25 per kW per year[36] (present value basis spread over 20 years). Compared to the base plant, the lower reservoir is the main addition to the overall project.

4.2.10. Compressed Air Energy Storage

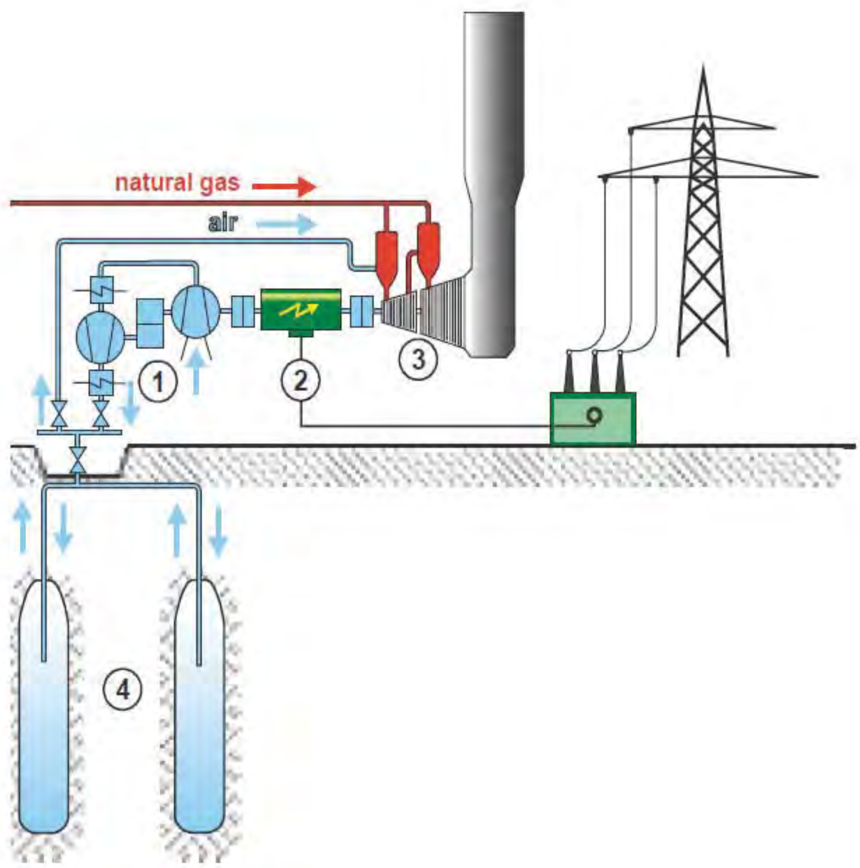
How is electricity generated using compressed air energy (CAES) storage?
CAES commonly uses a compressor during off peak hours to store air in an underground cavern or an above-ground tank. When electricity is required, the compressed air is released through a recuperator, increasing in temperature, and ignited with natural gas to rotate a turbine. The rotating shaft of the turbine is connected to a generator which converts the energy of the shaft into electrical energy.

A typical plant consists of an injection compressor, a storage facility and a fired expansion turbine. The typical arrangement is a single train with the compressor and expander each connected to a common motor/generator via a clutch.

High-pressure air is typically injected into a storage reservoir in an underground geologic formation such as a saline aquifer or abandoned mine for large-scale CAES applications (although it is possible to use surface piping systems and reservoirs, these are usually impractical due to high costs). Storage pressures typically range from 50 to 80 bar (g), and limits will depend on the storage reservoir site-specific characteristics such as depth and geology. The simplified CAES system considered for this study is shown graphically in Figure 57.

[36] Machinery cost is the sum of $910 per kW (base plant) + $360 per kW (pump-turbine/motor-generator features) = $1,270 per kW x 40 per cent capital renewal spending = $25 per kW per year (20 year basis).

Figure 57: A simplified compressed air energy storage system
(1. Compressor, 2. Motor/Generator, 3. Turbine, and 4. Storage Reservoir)



In storage mode, electricity from the system (2) drives a motor to compress air at high pressure (1), which is then stored in the storage reservoir (4).

In generation mode, the stored high-pressure air from the storage reservoir (4) is delivered to the combustors where heat is added prior to the turbine (3), which drives the generator to produce electricity (2). To increase efficiency, a recuperator is added to recover heat from the turbine exhaust to preheat the air withdrawn from the storage facility upstream of the combustor.

CAES systems are mainly used for energy storage and as backup for wind. Although the CAES system uses about 70 per cent less natural gas than regular combustion turbines, there may be associated costs to compress the stored air, depending on the source of electricity. The costs could be as low as zero if sourced from wind generation. Normally the costs are associated with off-peak electricity prices. This study assumed market prices for the electricity required for compression of air.

For this study, the plant configuration was assumed to include a 100 MW generator with 12 hours of operation, 67 MW of compressor power (with re-pressure time of 12 hours), and storage volume of 1,200 MWh.

It was assumed that pipeline gas would be available at adequate pressure (30 bar (g)) to support plant operation at rated load under all ambient conditions without on-site gas booster compressors. The charging electricity ratio (CER) is the ratio of generator output in kWh to compressor motor input in kWh. For the above plant, the CER is 1.5. Typical CERs range from 1.2 to 1.8.

This technology can be considered commercial, yet immature, as there are only a few CAES plants in operation. The following plants are in operation:

- E.N. Kraftwerke's 290 MW CAES Plant in Huntorf, Germany – went online in 1978; and
- Alabama Electric Cooperative's 110 MW CAES Plant in McIntosh, Alabama, U.S. – went online in 1991.

As of February 2009, the EPRI announced a program to develop advanced CAES plants and is seeking utilities to participate in two demonstration projects. One will use below ground air storage for bulk storage (at about 300 MW with 10-hour storage). The other will use an above-ground air vessel/piping system for short-term storage (at about 15 MW with 2-hour storage).

The overnight capital cost of a CAES plant within the 100 to 300 MW range has been estimated at between $1,010 and $1,260 per kW, excluding the cost of the underground storage reservoir, switchyard, transmission and owner's cost. The cost for preparing and upgrading the underground air storage reservoir will be site-specific but could range from $120 to $600 per kW for 1200 MWh of storage volume per day. The total overnight cost is thus estimated to range between $1,130 and $1,860 per kW (2013 dollars) for plants in the 100 to 300 MW range. Due to economies of scale, the higher cost would typically be associated with the smaller plants; as such, the total overnight costs for a 100 MW CAES plant are estimated at $1,600 per kW, which includes the storage cost.

A CAES plant would be most economic when sited on an abandoned mine site. Based on limited research, there are a significant number of abandoned mine sites in southern New Brunswick between Saint John and Moncton [NB DNR Report][37]. Salt caverns are particularly attractive as storage reservoirs, and there may be some potential in the Sussex area where Potash Corporation of Saskatchewan has active potash and salt mining operations.

The operational costs for this alternative include costs for operators of the facility, maintenance, labour and materials and the administrative costs to provide the facility service.

[37] NB Department of Natural Resources – Abandoned Mine Sites Policy – Policy MRE 006 2004.

Non-fuel operating and maintenance costs were based on the simple-cycle combustion turbine peaking plant numbers as given in Section 4.1.2.1 (Combustion Turbines).

The project lead time was estimated based on simple cycle peaking plant, and factored to allow for the longer lead times for the compressor/generator equipment as it is a highly customized design. The project lead time would be approximately 30 months, assuming that the geological formation had been previously located and investigated during the feasibility study phase (not included in the lead time). This CEAS plant would have an accounting life of 30 years.

4.2.11. Community-Distributed Generation

This section addresses opportunities for harnessing New Brunswick's natural resources in renewable energy. A recap of the potential supply-side options for distributed generation is provided. In addition, a discussion about programs enabling community-distributed generation is provided.

Program Support
The government of New Brunswick and NB Power have a variety of programs that encourage community distributed generation. These programs spur decentralized generation and broad geographical distribution of renewable energy sources.

The following is a brief description of New Brunswick's community-distributed generation opportunities that include:

- Net Metering;
- Embedded Generation program; and
- Community Energy Program (currently under development).

The supply options for these distributed-generation programs include:

- Small Hydro (see 4.2.1 for additional information);
- Biomass (see 4.2.4.1 for additional information);
- Small Wind of up to approximately 10 MW (see 4.2.2 for additional information); and
- Solar Photovoltaic (see 4.2.7 for additional information).

In addition to these formal programs, NB Power also promotes regionally distributed generation through power purchase agreements with NB Power to meet renewable electricity targets. Historically, these agreements have been procured through a Request for Proposal (RFP) process.

Net Metering

NB Power has a net metering program that allows customers to produce their own renewable energy by connecting a generation unit of less than 100 KW to NB Power's distribution system. In order to qualify for this program, the generation units must come from renewable energy sources compatible with Environment Canada's Environmental Choice Program[38] and Ecologo Certification[39], and standards for renewable low-impact electricity products such as biogas, biomass, solar, small hydro or wind.

A special net meter records the electricity NB Power delivers to the customer and the electricity NB Power receives back from the customer's generation unit. The customer is then billed for any net amount of electricity consumed and receives a credit for power sold into the grid. Any credits unused during the current billing period are carried forward to subsequent billing periods until March 31 of each year, after which credits are reduced to zero. This enables the customer to offset some of their consumption by generating their own power. However, because of its limit of 100 KW, the net metering program is generally of interest to residential and small commercial operations only.

Embedded Generation

With the embedded generation program, potential developers, or Independent Power Producers (IPP), can connect their environmentally sustainable generation unit to NB Power's 12 kV distribution system. Typical embedded generators may include landfills or sawmills.

The embedded generation unit may range in size from 100 kW to 3,000 kW. However, certain areas of the distribution system are more limited than others. This means that generation output may be limited or restricted in certain areas of the province. The initial allocation for these programs is 21,000 kW.

The embedded generation program is unlike the net metering program because the IPPs energy output is not used to offset their existing electricity consumption. Rather, NB Power purchases the renewable energy and environmental attributes at a set Feed-in tariff.

The Feed-in tariff is designed to make it easier for IPPs to sell their electricity to NB Power at a fixed and stable price under a long-term contract.

The Feed-in tariff effective October 1, 2013 is $0.09923 per kWh. This is based on the cost of electricity supplied from the distribution system. The embedded generation program is currently under review to better align with the Reduce and Shift Demand (RASD) initiatives and with direction from the new *Electricity Act*. The current target of enrolling 21 MW of renewable generation on the distribution system has been achieved.

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[38] http://www.ec.gc.ca/energie-energy/default.asp?lang=En&n=4F903768-1
[39] http://www.ecologo.org/common/assets/criterias/CCD-003.pdf

Community Energy Program

NB Power has assumed that development of energy resources from local small-scale projects would occur as part of government's energy action plan, *The New Brunswick Energy Blueprint*. This action plan provides direction that will

1. support local First Nations small-scale renewable projects,
2. integrate current and future wind generation in the most cost-effective and efficient manner, and
3. support promising solar, bio-energy and other emerging renewable energy technologies.

This IRP has assumed a phased in approach of this development so that by 2020, 75 MW of incremental new renewable capacity will be added to the system. To manage the integration of this development with the system, NB Power will focus on projects that provide dispatch flexibility and can integrate with NB Power's smart grid initiative.

4.3. Existing Supply, Life Extension and Conversion

4.3.1. Millbank and Ste. Rose Life Extension

This generation option is for upgrades to the existing Millbank and Ste. Rose Generating Station (pictured below) in the form of a retrofit of combustion turbines and a life extension program for an additional 25 years.

Figure 58: The Ste. Rose Generating Station

The total project cost of this retrofit was estimated at $200 per kW. This is a preliminary estimate from plant engineering staff and is based on normal running hours over the next 15 years of its current lifecycle.

5. RESULTS OF SUPPLY ANALYSIS

5.1. Levelized Cost of Electricity

The following sections provide a detailed analysis of all supply options included in this IRP. Each supply option was evaluated using the Levelized Cost of Electricity (LCOE) methodology, which is described in greater detail in the next section. This is an important step in the IRP process because it allows the system planner to rank and choose the appropriate supply option candidates from the larger portfolio of options.

The analysis provides the total accounting life cost comparison of each project, which is expressed as an equivalent electricity price in dollars per megawatt hour ($ per MWh). The full accounting life cycle costs include capital, operating and maintenance (O&M), fuel and environmental costs. In this analysis, the levelized electricity prices were expressed in 2013 dollars so that they could be easily compared to NB Power's current costs of electricity generation.

5.1.1. LCOE Methodology

The LCOE methodology is the economic assessment of the cost of the energy/generating option. It includes all of the costs over its lifetime, namely

- initial investment,
- O&M,
- cost of fuel (if applicable),
- cost of capital (interest),
- environmental costs (if applicable), and
- taxes (if applicable).

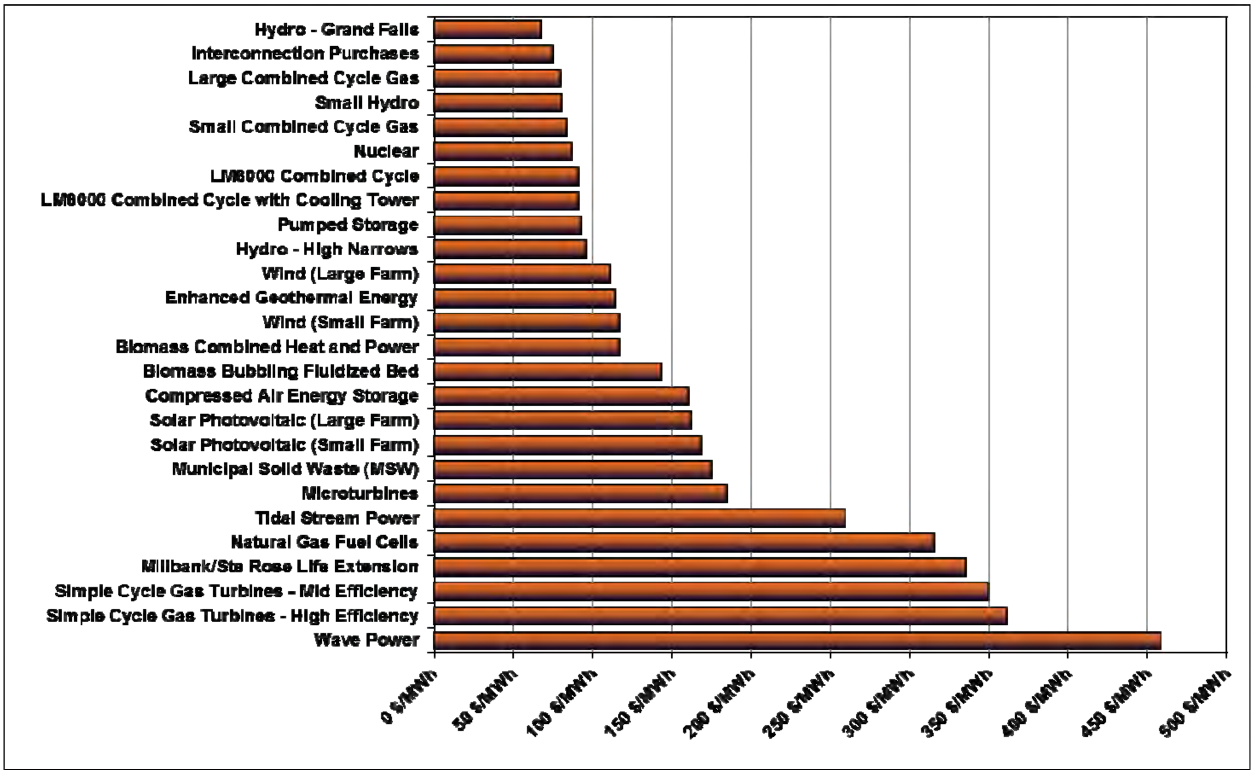
The LCOE is the net present value of the total cost stream of all the items listed above for a given generation option over its economic life to generate electricity. It was used to evaluate and compare the relative economics of each potential generation option. The LCOE is essentially the minimum price at which energy must be sold for an energy project to break even over the life of the project.

No financial risks associated with future construction prices or operating risks were included in the LCOE analysis. This was left to production cost modelling and sensitivity analyses. Also, it is important to note that the supply options considered in this IRP are of various sizes, fuel types, and varying levels of reliability. The latter is of particular importance because extra costs may be required to ensure an intermittent supply option (such as wind and solar) is reliable, by providing a backup to that supply option in the event it is not available. The LCOE analysis does not include the extra costs for backup for the intermittent options; the costs presented here are simply the cost of the stand-alone option, or the “sticker price” of that option.

The full costs of any of the supply options presented here are captured through the production cost modelling phase of the analysis, since the system is dispatched in economic order, and the lowest cost options are selected as needed to meet the load and reserve requirements without the risk of rolling blackouts. It is during the production cost modelling that the appropriate level of backup and the associated cost is included to support any of the intermittent supply option under consideration.

The following chart provides the LCOE and ranking for the supply options assessed in this IRP.

Figure 59 – Levelized cost of electricity



The options presented show a significant variation in electricity prices, from a low of about $70 per MWh to a high of over $450 per MWh. In many cases, the variations were due to the nature of the options and their level of maturity (commercialization). Another influencing factor was the assumed operating hours. Low operating hours of peaking units such as CT’s, Millbank and Ste. Rose will tend to increase the LCOE.

The most expensive renewable options are wave power and tidal power, which are well above $200 per MWh. Each of these options is in the very early phases of commercialization; therefore, the expected installation costs are high to account for the many unknowns such as technology choices and regulatory requirements. Although cost reductions are expected as technologies mature, recent trends highlight that high demand could lead to price increases. In this analysis, the projected installed costs of the various options were based on experiences to date and were escalated at the construction price index.

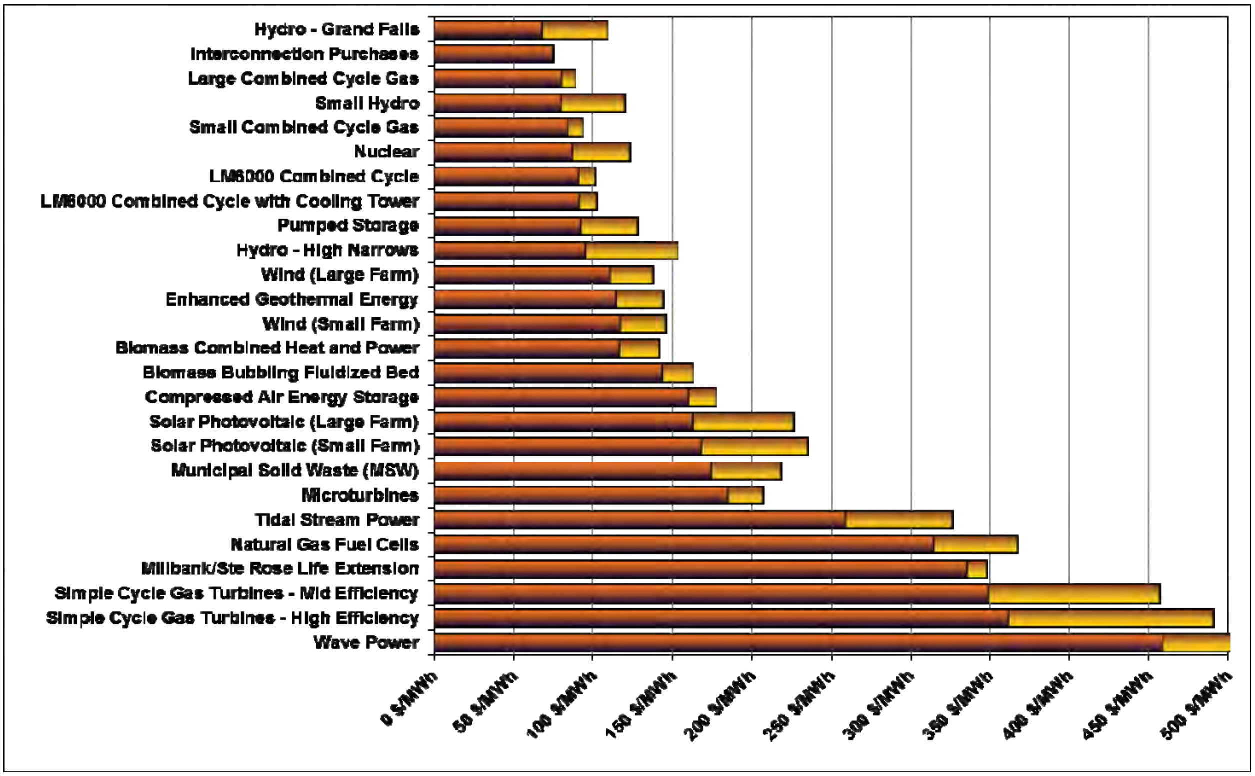
The supply options presented, and resultant LCOE depicted in the previous chart, were based on applying public funding for capital requirements. Assuming this arrangement, some of the options and resultant LCOE prices could compete with NB Power's existing total system costs of about $80 to $100 per MWh over the near term (of which about $20 per MWh is for distribution).

5.1.2. Private versus Public Financing

As mentioned in Section 3.8.5 (The Weighed Average Cost of Capital), the cost of capital for privately initiated power projects can be inferred from the most current actual experience of some of the major independent power producers (IPP's) located in Canada. Using this knowledge, this study assumed private projects average cost of debt to be 6.0 per cent[40] with an after-tax return on equity (ROE) of 16 per cent, to which a 65:35 debt-to-equity structure is applied. This produces an after-tax weighted average cost of capital (WACC) of about 8.33 per cent, assuming a composite income tax rate of 30 per cent. Applying these parameters to the supply options tends to increase the LCOE in comparison to publicly financed projects. Figure 60 illustrates the effect of these assumptions.

[40] This assumes a Government of Canada (GOC) rate of 3.0 per cent plus a 300 basis point (bp) spread for private entities with Dominion Bond Rating System (DBRS) rating of BBB-. See Section 3.8.5 (The Weighted Average Cost of Capital)

Figure 60: Levelized cost of electricity including the incremental cost of private financing:



On average, privately financed renewable projects will command a 30 to 60 per cent increase in electricity prices, depending on the project. On an individual basis, the following average increases in electricity prices are expected from private renewable projects:

Solar – 40 per cent
Tidal – 30 per cent
Wind – 25 per cent
Hydro – 50 per cent

Fossil generating options such as natural gas vary from about 10 to 20 per cent, and nuclear will command an increase of approximately 40 per cent. The variability in the incremental prices is mainly due to the weighting of capital investment versus fuel and O&M. Therefore one would expect that renewable energy projects, as well as nuclear projects, would incur the highest impact because the capital costs make up a larger portion of the total project costs.

5.1.3. LCOE Summary

Based on the LCOE analysis and the load and resource assessment performed previously, it is possible to formulate alternative system plans that can be evaluated in detail through production cost and financial modelling. All plans require options to address the current Renewable Portfolio Standard (RPS) requirements in the near term, as well as capital stock turnover in the longer term. The options required are a mix of base load and peaking requirements. In addition, the screening criterion has applied a price cap of $150 per MWh. This means that options with LCOE prices above this value would be culled. This criterion is selected to manage the number of options available to the Strategist model, which was used for production cost modelling. This model is explained in greater detail in Section 8 (Integrated Demand and Supply).

Based on this screening criterion, the following options have been selected for further evaluation:

- Hydro - Grand Falls;
- Interconnection Purchases;
- Natural Gas Combined Cycle;
- Small Hydro;
- Wind;
- Nuclear;
- Combined Heat and Power – Biomass;
- Enhanced Geothermal;
- Hydro - High Narrows; and
- Biomass Bubbling Fluidized Bed.

In addition, the following peaking options were selected for further evaluation:

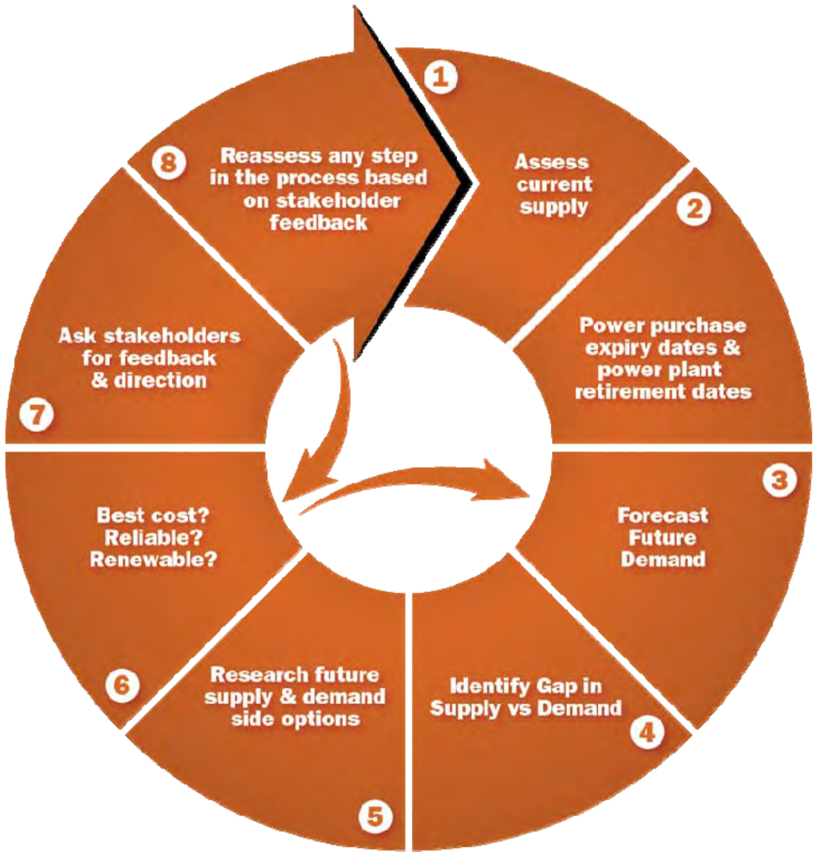
- Simple Cycle Gas Turbines – Mid-Efficiency; and
- Millbank / Ste. Rose.

5.2. Supply-Side Expansion Plan Evaluation

Expansion plan optimization analysis models the existing system as well as expansion options. It provides a total net present value cost as a key output for each expansion plan. The goal of supply-side evaluation is to find the least cost and environmentally acceptable supply plan that will reliably meet the electricity needs of New Brunswick.

At this point of the evaluation, particular focus is given in Step 6 of the IRP process shown in Figure 61.

Figure 61: IRP Process



In developing the reference supply plan, all reasonable and feasible alternatives identified in the supply-side screening analysis described in Section 5.1 (Levelized Cost of Electricity) were provided as input and run through PROVIEW to find the least-cost supply expansion plan to reliably meet the forecast future requirement of load and reserve within New Brunswick, with consideration of the RPS requirement of 40 per cent by 2020. PROVIEW is part of the Strategist suite of models developed by Ventyx Inc. of Atlanta, Georgia, to evaluate long-term resource plans. The PROVIEW model has been used by NB Power in developing previous IRPs and is used widely in the electricity industry. It has been reviewed and accepted by the New Brunswick Energy and Utilities Board (EUB).

PROVIEW produces thousands of combinations and permutations using dynamic programming techniques, and ranks the resulting expansion plans in order of increasing costs.

Using the PROVIEW model, system planners were able to study the expansion options in detail. Economic dispatch implications associated with differing seasonal load requirements, limited hydro plant energies and storage capability, and environmental constraints were included to determine detailed year-by-year production costs for all plans.

Expansion plan optimization analysis enables a quantifiable comparison of the expansion plans on a cost basis. In addition, comparison can also be made of system energy production, fuel usage, as well as emissions for each of the expansion plans. The flexibility of this modelling capability is not just used to determine a least-cost plan; it is also used to determine the plan's sensitivity and robustness to potential changes in different variables.

In summary, the process for supply-side expansion plan evaluation includes:

- Determining the lowest-cost supply expansion plan using basic assumptions;
- Calculating generation mix and GHG emissions; and
- Completing sensitivity analyses of different variables such as fuel prices.

5.2.1. Least-Cost Methodology

The PROVIEW analysis determined the least-cost supply plan that would meet the immediate system needs prior to 2027 and in the longer term, to address the aging NB Power generation fleet. The results are shown in Figure 62.

Consideration was also given to the least-cost plan that achieves the Renewable Portfolio Standard (RPS) anticipated under the *Electricity Act*. The RPS will require 40 per cent of New Brunswick energy requirements be obtained from renewable resources by 2020. The RPS requirement is expected to be a legal obligation within New Brunswick[41]. The least-cost plan, including RPS, will be used as the Supply Plan.

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[41] The RPS is not currently legislated but it is anticipated through guidance provided in the New Brunswick Energy Blueprint. The Energy Blueprint directs NB Power to have 40 per cent of in-province electricity sales provided by renewable resources by 2020.

Figure 62: Summary of least-cost supply expansion plan

In Service Date	Supply Plan	Scheduled Retirements
2014		
2020	75 MW Community Energy	
2026		Grand Manan (-29 MW)
2027	100 MW Grand Falls 89 MW Combustion Turbine (CT)	Bayside PPA (-285 MW)
2030	350 MW Interconnection Purchase Mactaquac Replacement	Grandview PPA (-90 MW) Mactaquac (-668 MW)
2031	Millbank /Ste. Rose Life Ext.	Millbank /Ste. Rose (-496 MW)
2032		Twin Rivers PPA (-39 MW)
2038	89 MW CT	
Net Present Value Cost (2013 dollars)	**$20,570 Million**	

The expansion plan includes 75 MW of Community Energy projects by 2020. This is to help meet the RPS target by this period. The expansion plan also shows major development in the period between 2027 and 2038 to respond to existing facilities' end-of-life schedules. The total net present value (NPV) cost shown, is expressed in 2013 Canadian dollars and includes all costs (total fuel and purchased power, new and existing O&M and new and existing capital requirements, as well as total costs for transmission, distribution and head office).[42] These costs were captured within the study period as defined between 2014 and 2038.

The development of the least-cost supply expansion plan was based solely on meeting in-province electricity requirements. The benefits associated with exporting electricity were captured after this process was complete. This allowed the surplus electricity to be made available for export and to capture potential benefits that then reduced the total net present value costs.

[42] With exception to costs associated with the replacement of Mactaquac expected in 2030. The replacement options and associated costs for this project are currently under review.

It is noteworthy that the least-cost plan selects the Grand Falls supply option as the first new supply requirement to meet peak demand. The Grand Falls supply option also becomes a cost-effective way to help NB Power meet its obligation under the RPS. The plans also show several combustion turbines (CTs) and life extension of Millbank and Ste. Rose to meet peak load requirements. In addition to this, and to respond to the expiration of the Bayside and Grandview PPAs, a long-term interconnection purchase is selected. Finally, it is assumed in this assessment that the loss of Mactaquac in 2030 will be replaced by an equivalent amount of renewable electricity. The options and associated costs for Mactaquac replacement will be fully assessed in a separate study.

6. ENERGY EFFICIENCY AND DEMAND MANAGEMENT

6.1. Demand-Side Management Study

An important part of the integrated resource planning process is recognizing that conservation, energy efficiency and load demand management, also referred to as demand-side management, is a potential low-cost alternative to developing new power plants. Demand management is any attempt to change or influence the demand placed upon the system by the customer. It encompasses a broad range of techniques from the direct control of customer equipment to educating customers about conserving electricity.

Figure 63 outlines the overall IRP study process. This section of the report outlines the detailed procedures employed in evaluating the demand-side options portion of Step 5 shown in Figure 63. As in the supply-side evaluation, Step 6 is also used to assess the effectiveness of demand-side management.

Refer to Section 1.3 (The IRP Process) for additional information.

Figure 63: IRP Process

Although North American utilities have recognized the value of energy efficiency and demand management since the 1960s, management of demand side did not start until a decade later. In the early 1970s, inflation, environmental concerns and escalating fuel prices began to have significant effects on energy costs. In 1973, the Organization of Petroleum Exporting Countries (OPEC) shocked the world with an oil embargo. The high inflation that resulted caused the cost of electricity from new power plants to be as much as 10 times higher than that generated at existing plants.

Utility planners were motivated by the vision of a sustainable energy future. They increased their focus on potential achievable conservation, energy efficiency and load demand management in conjunction with traditional generation alternatives to limit

- negative effects on the environment,
- the financial impact of fossil fuel prices, and
- future rate increases to customers.

The combination of supply-side and demand management options which incur the lowest costs, consistent with other important goals, has become known as least-cost, integrated resource planning (IRP) and is actively used by many utilities, including NB Power.

Prior to this plan, NB Power completed four internal IRPs: in 1990, 1995, 2002 and 2010. During the same time period, NB Power was also involved in several other demand management studies conducted by the New Brunswick Department of Energy.

6.2. Demand Management Approach and Methodology

Energy efficiency and conservation is an integral part of NB Power's Reduce and Shift Demand (RASD) program. It is the "reduce" part of the RASD program. This part of the program provides benefit to the participating customers through direct savings on their power bills. It also provides benefit to NB Power through immediate fuel cost savings and through lower capital requirements in the long term by reducing the need for new supply in the future. This, then, provides indirect benefit to all customers by ensuring low and stable rates.

The other part of the RASD program is the "shifting" part. This part of the program will be enabled through smart grid technology that will allow the systematic control of participating customers load. Smart grid is described in greater detail in Appendix 12 (Smart Grid). The shifting of demand will benefit the utility by improving the utilization and operation of generating plants, and through an overall improved efficiency in operating the transmission and distribution systems. This also provides indirect benefit to all customers by ensuring low and stable rates.

The RASD program is a holistic approach that improves energy efficiency to both customers and NB Power. This section describes the approach and methodology used to develop the energy efficiency (reduce) and demand management program (shift) used in this IRP.

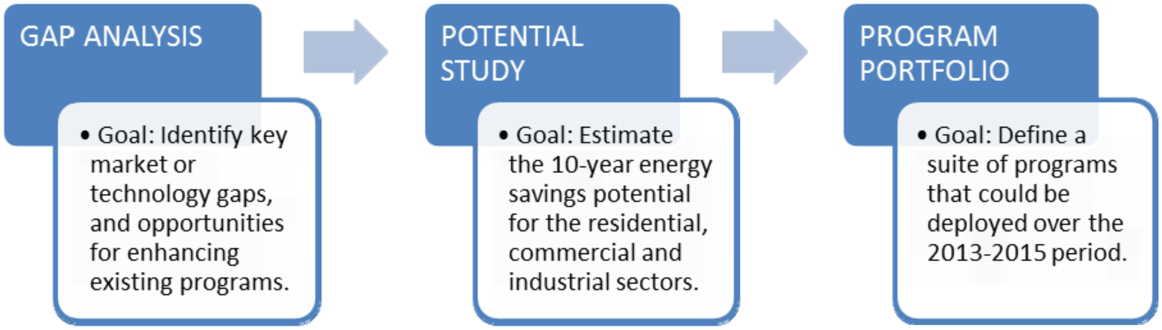
The demand management and energy efficiency program at NB Power began following the release of the *New Brunswick Energy Blueprint* in October 2011, which presented a detailed action plan for implementing a strategic direction for the province's energy future over the next 10 years.

Included amongst the 20 government actionable items was the development of a three-year electricity efficiency plan by the electric utilities, in conjunction with Efficiency NB**,** a government Crown Agency. The objectives of the document are threefold:

1. outline the thorough process and detailed work that led to the development of the Plan;
2. present the program investments and the associated benefits; and
3. provide an overview of the existing and new programs and activities, aimed at helping the province's citizens and businesses to reduce their electricity bills.

In early 2012, a steering committee was established to define an initial three-year electricity efficiency plan. The committee was comprised of senior officials from the following utility and governmental organizations: NB Power; Saint John Energy; Edmundston Energy; Perth-Andover Electric Light Commission; Efficiency NB; the Department of Energy and Mines; and the Department of Environment and Local Government.

The services of a consulting firm, Dunsky Energy Consulting, were retained to assist the Committee in this endeavour. More specifically, the consulting firm followed a three-pronged approach as outlined below.



The committee met on a regular basis to review and discuss the consultant's work, with the ultimate objective of designing a triennial plan that maximizes the benefits for the province in the short-term, and establishes a solid foundation for increased investments in the future should more resources be made available.

Significant economic, social and environmental benefits will result from these investments. The following list highlights the key benefits of the plan.

- Save 90 GWh and 24 MW of electricity annually by 2015, i.e., equivalent to the annual electricity consumption of 5,400 households.
- Result in $96 million in bill savings to consumers and businesses over the life of the energy efficiency measures.
- Offer $38 million in incentives to consumers and businesses.
- Generate $61 million of spending in electricity efficiency products and services.
- Provide a 4:1 benefit to cost ratio for dollars invested by consumers and businesses.
- Improve comfort and air quality in homes and commercial buildings.
- Create jobs, more than 734 net “person-years” of employment.
- Reduce 41,000 tonnes of CO_2 emissions by 2015, the equivalent to avoiding the emissions of 7,730 cars for one year.

The following sections provide a short description of the programs and activities stemming from RASD. A balanced approach was taken in determining the areas of investments in order to capture cost-effective electricity efficiency measures across the sectors and to address new, innovative energy technologies and strategies. Based on sound management practices, the plan will be revisited on a regular basis by assessing program results and market conditions and by seizing new opportunities that may arise.

6.2.1. Households

Residential Energy Efficiency Program for Existing Homes (REEP)
This program provides financial support to homeowners and residential multi-unit building owners in planning and undertaking their energy efficiency projects, such as installing attic and basement insulation and energy efficient heating systems. It is important to note that homeowners have access to incentives for the implementation of renewable heating systems (e.g., ground source heat pump, pellet stove and solar domestic hot water) and high-efficiency ductless heat pumps, the latter technology being of particular interest to owners of baseboard-heated homes. By providing financial support to both pre- and post-upgrade evaluations, homeowners will receive significant help to drive cost-effective upgrades and renovations that lead to the projected energy savings, thus providing them quality assurance.

Various activities will be undertaken to ensure ongoing success and uptake in home retrofit programs, including marketing campaigns and capacity-building workshops with contractors.

Fall 2013 New Initiatives
In the Fall of 2013, New Brunswick households were able to take advantage of three new initiatives: mass-market energy efficient products; installation of free energy efficient products during their home energy evaluation; and a comprehensive home retrofit program for low-income households. These were designed to make energy savings more accessible to all New Brunswickers.

Mass-Market Energy Efficient Products Program
NB Power, in co-operation with Efficiency NB, offered a $75 mail-in rebate to residents purchasing eligible clothes washers and refrigerators in the fall of 2013. Additional rebates will be designed and rolled out during the next three years and will target a host of products such as electronic thermostats, regular and specialty compact fluorescent lamps (CFLs), light-emitting diodes (LEDs) and low-flow shower heads. The program builds upon a close partnership between Efficiency NB, and home improvement and appliance retailers across the province, to raise awareness of energy efficiency and engage consumers to take action. Municipal utilities' customers have access to this province-wide program, which will be promoted through both traditional and social media.

Energy Efficiency Products
NB Power, in collaboration with Efficiency NB, is currently offering homeowners free installation of highly cost-effective products, while the upgrade evaluation is conducted under the Residential Energy Efficiency Program (REEP). Products that may be installed include: low-flow shower heads, regular and specialty CFLs, LEDs, kitchen and bathroom faucet aerators, and water heater pipe wrap. This "direct install" approach provides immediate value to the homeowners and ensures a minimum amount of energy savings to offset upfront assessment costs, which improves the program's cost-effectiveness. Municipal utilities' customers can also benefit from this new initiative.

Low-Income Efficiency Program
A new program offered by Efficiency NB has been specifically designed to address the particular needs of low-income homeowners. The program will soon begin to identify a fixed number of eligible homes each year and will carry out fully funded and facilitated retrofits for energy efficiency. It will target homes in need of major efficiency upgrades, especially insulation and heating systems, resulting in significant energy savings for homeowners who have difficulty meeting their household financial obligations.

2014 New Initiatives
Two additional initiatives will be developed and deployed in the course of 2014:

Water-Saving Devices Program
NB Power will move to offer free or cost-shared water-saving devices (e.g., low-flow shower heads, faucet aerators and drain water heat recovery systems) to customers who lease a new domestic hot water heater through the provincial utility. The "direct install" approach will

leverage the leasing program infrastructure to deliver greater value to customers while reducing overhead costs.

Home Energy Report Program

NB Power will launch a pilot project through which select customers will receive a personalized energy report. The report will help customers to better understand their energy usage, and to compare their consumption with that of their peers. This type of report has proven successful in many provinces and US states, informing and empowering households to adopt more energy-conserving habits and measures.

Also note that NB Power will work closely with the province's municipal utilities, with a view to assisting them in the design and implementation of similar initiatives for their own customers.

6.2.2. Business and Government

Energy Smart Program

This program is designed to assist existing commercial building owners and operators, whether small or large, to make their buildings more energy efficient and reduce operating and maintenance costs. Financial incentives are offered to help offset the costs of the energy audit and resulting energy conservation upgrades, including renewables (i.e., geothermal and solar). Over the next three years, various activities will be undertaken to ensure ongoing success and uptake in the program, including hosting workshops to help build capacity amongst commercial building owners and the commercial energy management workforce, as well as working closely with the energy management service providers who perform the building audits to ensure their quality and accuracy.

LED Street Lighting Program

During the plan's time frame, NB Power will actively promote its LED Street Lighting program to municipalities across the province, This initiative, which was launched in 2012, involves replacing the 72,000 high pressure sodium (HPS) street lights, which municipalities are currently renting, with more efficient LED lights. The replacement will take about five years to complete, following a balanced schedule of planned maintenance cycles, new installations and strategic change-outs.

New Initiative

NB Power will introduce its new Prescriptive Energy Efficiency Program aimed at helping small and medium industries (SMI) purchase high-efficiency equipment such as pumps and motors. A "prescriptive program" is one that establishes a pre-defined list of standardized products that are eligible for financial support, and prescribed incentive levels that are available to customers. Developing a close partnership with supply chain vendors and contractors will ensure that these important market entities can successfully assist the small and medium industries in selecting and installing products that meet their needs. As in the case of residential programs, NB Power will support municipal utilities in deploying a similar program in their service territory.

6.2.3. Enabling Strategies

Enabling Strategies (Cross-Sectoral)

Enabling strategies go beyond individual program markets to sustain long-term energy savings. Investing over the next three years in initiatives that cut across customer sectors and programs—province-wide education and awareness campaigns, contractor training and workshops, trade ally partnerships, strategic programmatic planning and program evaluation activities—produces ripple effects in the short-, mid- and long-term. Such investments should be viewed as seed money for developing a self-sustaining and flourishing energy efficiency industry.

6.2.4. Smart Grid Strategy

An important part of NB Power's RASD strategy is the implementation of smart grid infrastructure and associated capabilities that can be leveraged to achieve the demand reduction strategies described above. The smart grid strategy for NB Power goes well beyond the installation of the smart meter. The strategy brings together a comprehensive framework to achieve key objectives across many domains of the organization including operations, customer service, asset management, products and services, and demand management to name a few. Appendix 12 (Smart Grid) explains in greater detail this value framework and how it will be achieved through NB Power's partnership with Siemens.

The development of the smart grid for the achievement of demand management takes a holistic approach to energy efficiency. Traditionally, energy efficiency focused on end use or customer load management. The smart grid continues to achieve this but also allows the utility to utilize its assets more efficiently and reduce losses which improves the efficiency of the entire electricity system, from the generator through to the customers load.

6.2.5. Beyond the First Three Years

The three-year plan was developed from a long-term view that determined approximately 600 MW of capacity and approximately 2 TWh of energy reductions are available. This plan puts NB Power—and all of New Brunswick—on the path to achieving these reductions. The analysis and research used to develop the three-year energy efficiency plan, was used to inform the longer-term costs of the programs used in the integration process.

As mentioned, the deployment of Smart Grid technology plays an important role to enable and enhance many of the programs required to achieve the capacity and energy reductions described above. Smart Grid will also contribute to the increased integration of renewable resources, both centrally and as distribution generation, and to the increased efficiency of the grid operations. NB Power's Smart Grid plan is described in detail in Appendix 12.

In combination, energy efficiency (reduce) and demand reduction (shifting) makeup the RASD program. This program includes all costs to implement energy efficiency and demand reduction programs as well as infrastructure costs for smart grid implementation. The total costs of the RASD program are projected to be in the order of $487 million on a net present value basis over the 25 year study period.

The following reductions in electricity requirements are expected from this investment over the next 25 years.

Figure 64: Potential RASD reduction schedule

Year	MW	GWh
1	13	27
2	13	61
3	34	125
4	45	193
5	84	266
25	609	2,014

7. STAKEHOLDER CONSULTATIONS

7.1. Overview of Stakeholder Consultation Process

Section 100 of the *Electricity Act*, passed October 1, 2013, obliges NB Power to submit an Integrated Resource Plan (IRP) to the Energy and Utilities Board (EUB) as part of the utility's long-term planning process. The Act also obliges NB Power to include "a description of the stakeholder consultations carried out by the Corporation in developing the integrated resource plan."

To achieve the objectives set out in the legislation, and to achieve NB Power's own goals of improved transparency regarding our planning process, and improved energy literacy among our customers and stakeholders, NB Power chose a facilitated workshop method that is commonly accepted in public engagement processes to solicit meaningful input from individuals and groups.

Stakeholders were invited to participate according to a defined Terms of Reference (Appendix 4) which included individuals who had interacted with NB Power in the previous 10 years on behalf of a particular interest group or sector, individuals who had identified themselves as an intervener representing a special interest group at prior EUB hearings, and representatives of government, industry, residential and business customers, environmental groups, academia, First Nations and other special interest groups. Staff members of the Energy and Utilities Board were also invited to attend as observers.

A total of 118 invitations were sent to individuals and groups (list of invitees attached as Appendix 5), via an e-mail that encouraged attendance at the full day session (Invitation text Appendix 6). When stakeholders confirmed attendance, NB Power provided a discussion guide in the language of their choice with background on the utility's long-term planning process and the IRP (attached Appendix 7). Stakeholders were also provided three key questions to consider in both the text of the e-mail invitation and in the discussion guide prior to the session.

It should be noted that invitations were circulated outside NB Power's specific invitee list, which resulted in extra participants requesting attendance. These requests were accepted (with the exception of a leader of a political party, who received a separate presentation as part of a similar set of briefings to political leaders and their parties), and a broader group than previously considered was represented at the session, particularly in the area of environmental interest groups.

NB Power publicized the event through a news release (Appendix 8) posted on NB Power's website the morning of January 30, 2014, and on the Government of New Brunswick's website on January 31, 2014. This release was circulated on social media via NB Power's Twitter feed to approximately 4,420 followers on January 30, 2014.

7.2. Description of Stakeholder Workshop

The stakeholder session was held Friday, January 31, 2014, at the Crown Plaza Hotel in Fredericton. Of the 118 invitations sent, 58 stakeholders expressed interest in attending, and of those, 51 attended (a scanned copy of sign in sheet is located in Appendix 9). By the end of the day, participants provided 128 written suggestions and completed 24 exit surveys (Appendix 10) from which these highlights are taken. The complete list of suggestions can be found in Appendix 11.

The workshop began with opening remarks from Keith Cronkhite, NB Power Vice President of Generation and Business Development, followed by presentations having three key areas of focus.

1. Brad Wasson, Program Director for NB Power's Reduce and Shift Demand initiative presented on the history of NB Power's planning processes and the forces of industrial and environmental change that are causing NB Power to adapt its business model and planning processes.
2. George Porter, Project Manager for the Mactaquac Project, presented on the future options being considered for the Mactaquac Generating Station and the decision process that will assist NB Power in determining a preferred option by 2016.
3. Michael Bourque, Director of Integrated Resource Planning, demonstrated how NB Power forecasts how much capacity will be needed in the future, how current supply is determined, various options being considered to fill the gap and how stakeholder input factors into the planning process.

Figure 65: Brad Wasson, Program Director for Reduce and Shift Demand presenting at the stakeholder workshop

Following the presentations, participants were offered 90 minutes for lunch and one-on-one Question and Answer (Q and A) sessions with a variety of NB Power subject matter experts on the topics of interest to them. More than a dozen senior-level NB Power employees were made available during the Q and A sessions, including President and CEO Gaëtan Thomas, and managers and directors from environment, planning, finance, transmission, distribution, generation, First Nations relations, government relations, and communications and public engagement areas of the company.

In the afternoon, facilitator Marc Babineau asked participants to consider once more the three broad questions provided to them in their letter of invitation and in the discussion guide on the Integrated Resource Plan, which were posted on the wall, and read as follows:

> *Given that:*
>
> *NB Power must operate within the boundaries of its legislative and regulatory mandates to provide reliable electricity with best-cost solutions that achieve low and predictable rates in a way that sustains the social and natural environment and,*
>
> *The Energy Blueprint has committed NB Power to incorporate 40 per cent renewable energy into the grid by 2020,*
>
> 1. *How can NB Power help contribute to a successful New Brunswick?*
> 2. *How can NB Power help contribute to a clean environment for future generations?*
> 3. *What role could NB Power play in ensuring the development of new opportunities for energy innovation in New Brunswick?*

Each participant wrote individual answers to each question and read them aloud to the participants in room, and each answer or suggestion was posted on the wall and grouped into categories by NB Power staff.

Participants were then each given three sticker dots and asked to consider each suggestion and "vote" on the ones they most agreed with. Participants were permitted to put their dots on the suggestions they identified with the most, including on their own suggestion, and could use all three dots on the same suggestion if they wanted, or spread them throughout the suggestions as they wished.

7.3. Key Areas of Input and Suggestions

Suggestions from participants in response to the questions fell into 10 key themes, summarized in the highlights below.

Efficiency and Conservation

Most participants felt strongly that NB Power should encourage homeowners and businesses to become more energy efficient through additional retrofit programs, greater co-operation with federal and provincial efficiency programs, by assisting large industrial energy users in reducing their peak demand and by providing customers with energy efficient products and services.

Ideas included supporting alternatives to electric baseboard heating (and actively discouraging baseboard heating), supporting a new housing standard that uses more energy efficient building materials, and providing incentives to residential customers who want to install green technologies in their homes.

Participants felt NB Power could use conservation and efficiency to reduce in-province energy demand, which could help increase the percentage of renewables on the grid and make more domestically produced energy available for export sales.

Some suggested that efficiency and conservation should be considered as guiding principles and a component of rate structures, including peak rates for all customers. One participant summed up the comments of several stakeholders in the following way: "In many jurisdictions, targeted higher energy rates combined with stringent efficiency and progressive renewable energy programs have led to lower energy bills, as well as sustainability and resilience."

Target-setting and Measurements

Most participants suggested NB Power could consider a broader range of factors in the Integrated Resource Plan including "more rigorous environmental metrics" that align with provincial and federal initiatives, setting more ambitious targets for renewable energy (and phasing out coal and fossil fuel), and including the cost of primary and secondary environmental damage in the analysis.

The suggestions that received the most "votes" for the day were similar: asking that NB Power consider "efficiency and conservation as part of the equation," along with supply, load and cost, when developing the Integrated Resource Plan (thirteen votes); and suggesting that NB Power implement a "full cost and full benefit accounting system" that includes all marginal costs (six votes).

Some suggestions for greater information in the IRP included: making a distinction between so-called "green energy," low carbon, and renewables, and definitions of how each can or does not contribute to a sustainable environment; and using maps of current and forecasted scenarios, including supply and demand for "business as usual" and "high-efficiency" scenarios.

Use of Renewable Energy Sources

Participants encouraged NB Power to explore more options for renewable energy sources, and maximize existing renewable generation. Suggestions included investing more in renewable energy technology such as wind and solar.

Participants also suggested NB Power work with Hydro Quebec to purchase renewable hydropower to attain the 40 per cent renewable portfolio standard.

Climate Change

Participants urged NB Power to "be a leader in mitigating climate change impacts" by maximizing additions of non-intermittent generation from zero or lower emission sources in Reduce and Shift Demand initiatives, limiting fossil fuel and biomass fuel use.

Suggestions for NB Power included working with communities to provide innovative electric solutions for public transport and taking on greater responsibility for transitioning the transportation sector from one dependent on fossil fuels to zero-emitting technologies.

Community-based Energy Development

Many participants urged NB Power to consider measures that would include locally produced, renewable energy in the grid and to support energy development that promotes community engagement.

Specific suggestions on how to accomplish this included: developing the smart grid to allow for two-way metering and net metering with no resets; facilitating renewable energy rentals; investing a percentage of earnings into local environmental initiatives; and promoting and prioritizing small green energy projects in regions rather than large generation assets that would require extra transmission.

Education and Research Co-operation

Many participants agreed on the need for NB Power to support applied research in energy at French and English universities and colleges, through financial investments and in-house research and development. Participants suggested NB could support research in the following areas: alternative and renewable energy sources, efficiency, innovation and energy technology. One participant suggested NB Power work with the provincial Department of Education to create specialized energy technology programs in schools to assist in the development of future energy innovators.

Public Engagement

Many participants encouraged NB Power to improve energy literacy among New Brunswickers as a way to help customers understand where their energy comes from and what they can do as individuals to use less of it.

Participants urged NB Power to place a high value on engaging all sectors—namely aboriginals (on and off reserve), youth and low-income consumers—and valuing equally the feedback that comes from those groups. One participant urged NB Power to “do more of what you are doing today – consulting with the public.”

Figure 66: Tony O’Hara Executive Director Engineering and Operations discussing energy options with stakeholders during IRP workshop

Among the specific ideas on how to educate and engage the public on energy issues were: including a “sustainability graph” on power bills; focusing on students and young people to help them engage personally and collectively in the sustainability process; being “open and transparent in sharing of plans” in order to assist business and industry to improve their long-term planning; and by seeking input from different sectors on how to encourage energy innovation through financial incentives.

Innovation and Business Development

Participants agreed that opportunities exist in New Brunswick to pilot and develop small-scale, technology-based renewable energy projects that could be a source of new employment for the province. Participants envisioned New Brunswick as a “living lab” where small and medium-sized enterprises could develop and deploy energy innovations in an incubator community, creating a new source of expertise and economic development.

Suggestions on how NB Power might contribute to this effort included: sponsoring an “energy focused component” to the activities of the NB Innovation Foundation; unlocking options by “getting out of costly nuclear energy”; by helping New Brunswickers to become active prosumers and energy planners; and by becoming a service provider of innovative energy products.

Other ideas included opening the market to sustainably produced community power (which NB Power could purchase), using a carbon tax for large emitters to subsidize community energy innovation, and changing the provincial *Electricity Act* to allow for innovation.

Finance and Rates Structure

Participants urged NB Power to maintain fair and competitive rates for all customers that are lower than regional alternatives, while focusing on stability, sustainability, reliability and remaining “light on our feet” to respond to changes in the marketplace.

Some participants focused on large industrial customers, suggesting NB Power create a rate structure for industry based on daily peak to encourage a shift in demand, and offering preferential rates for industrial customers.

To achieve long-term financial stability and environmental responsibility within the Integrated Resource Plan, participants suggested: factoring in a long-term plan that reveals the actual marginal cost of electricity via prices; providing incentives or preferential rates to industries or businesses that hire and maintain Certified Energy Managers (to ensure efficiency as a corporate priority); using “cheap, off-season power” to replace nuclear; creating an NB Power clean-tech venture capital fund to pay for pilot projects in New Brunswick; and adopting price-adders to reflect legitimate environmental costs in electricity rates, and remit the proceeds from same to an independent body for use to promote environmental goals.

Reliability

Workshop participants agreed on the need for a resilient power system that uses tried and proven solutions, with a well-balanced energy portfolio. If NB Power is to adopt a distributed generation system through infrastructure that supports new technology and innovation, it must be driven by a long-term plan that achieves resilience, reliability and sustainability.

8. INTEGRATED DEMAND AND SUPPLY

8.1. Introduction

To best develop a least-cost expansion plan, neither the supply-side nor the demand-side analysis results can be used in isolation. One of the major components of least-cost planning is the integration of energy efficiency and demand management programs (referred to as Reduce and Shift Demand (RASD)) in the planning process as a low-cost alternative to power plants. The results of the supply-side analysis can, however, be used as a supply reference plan for RASD integration wherein RASD has the opportunity to defer or displace a supply-side unit, based on competing economics of the RASD measure(s) and the generating unit.

The first step in this integration process was a preliminary economic screening of the RASD measures under consideration. During this screening, certain simplifying assumptions about RASD options and their interactions with supply-side generating plants were made in order to screen out only those measures which were obviously not cost effective and therefore did not need to be subjected to more detailed analysis. The screening analysis assumed that avoided capacity and energy costs could be calculated using combustion turbines for peaking needs and interconnection market purchases for base load energy requirements. This assumption tends to overstate the actual avoided energy costs because in actuality, no new capacity is required in the early years of the plan.

Another simplifying assumption used in the screening analysis was that the value of the avoided energy savings per kWh remains static no matter how much energy RASD programs remove. In reality, as energy and demand is removed from the system, the avoided costs per kWh tend to decline. This diminishing value results from less efficient generating units being removed from the system dispatch as demand declines.

The final simplifying assumption used in the screening analysis was that any increment of RASD capacity, regardless of diversity, could defer an equivalent amount of supply capacity. In reality, only discrete blocks of supply capacity can be deferred. Therefore, in order for a RASD measure to successfully avoid the need for capacity, it must be of sufficient size, either by itself or in combination with other economically desirable measures.

In order to properly evaluate RASD options, the simplifying assumptions listed above must be removed. The RASD and supply-side options must be allowed to compete equally in a detailed and realistic simulation. The PROVIEW dynamic program expansion planning software model was used to evaluate the ability of RASD options to realistically avoid or defer generation requirements. PROVIEW is an automatic expansion-planning model that is used to determine the least-cost balanced demand and supply plan for a utility system under a prescribed set of constraints and assumptions. PROVIEW realistically simulates the operation of a utility system to determine the cost and reliability effects of adding resources to the system or of modifying the load through RASD technologies. In this study, the dynamic programming process simulated full capital and production cost effects of thousands of feasible combinations of RASD and supply-side options.

8.2. Integration Approach and Methodology

8.2.1. Supply Assumptions

Based on the results of the supply-side analysis, the least-cost supply-side resource expansion plan outlined in Figure 67 was used for RASD integration.

Figure 67: Supply Plan

In Service Date	Supply Plan	Scheduled Retirements
2014		
2020	75 MW Community Energy	
2026		Grand Manan (-29 MW)
2027	100 MW Grand Falls 89 MW Combustion Turbine (CT)	Bayside PPA (-285 MW)
2030	350 MW Interconnection Purchase Mactaquac Replacement	Grandview PPA (-90 MW) Mactaquac (-668 MW)
2031	Millbank /Ste. Rose Life Ext.	Millbank /Ste. Rose (-496 MW)
2032		Twin Rivers PPA (-39 MW)
2038	89 MW CT	
Net Present Value Cost (2013 dollars)	**$20,570 Million**	

At this stage, the alternatives in the Supply Plan will now compete with the RASD measures to determine the least-cost mix of supply- and demand-side options. RASD programs could defer or completely displace a supply-side resource option during the integration phase. However, the addition of RASD programs obviously would not advance the timing of supply-side addition, nor would RASD cause more power sources to come online than in the Supply Plan. The exception to this would be that resources to meet the RPS requirement (having 40 per cent of New Brunswick's electricity sales come from renewables by 2020) would need to be maintained. Therefore, resources such as the 75 MW of community energy needed to help meet the RPS would not have an opportunity to be deferred or eliminated with the integration of RASD.

8.2.2. RASD Assumptions

Only RASD measures that passed the cost-effective screening were offered in the PROVIEW optimization as a RASD alternative, either individually or grouped with similar measures. The logical grouping of measures according to their nature, operating lives and levelized cost per kW significantly reduced the size of the dynamic programming problem within PROVIEW. The total amount of reductions available as RASD alternatives was 609 MW of demand and 2,014 GWh of energy by the end of the study period in 2038.

For the integration phase of the analysis, NB Power system planners assumed a 25-year schedule of all RASD measures available as an expansion plan alternative. This alternative was made available starting in 2014 at the earliest, and was allowed to slide, depending on the most economic timing. This was done for two reasons: to simplify the optimization problem and to avoid “over-optimization” of imperfect data estimates. The data used in the screening analyses included best estimates of probable impact and penetration. Also, a projected ramp-up schedule is modelled because RASD measures take time to implement and require continuous commitment to ensure their full impact on the generating system over a span of many years.

The following schedule of potential demand and energy reductions was established and made available for integration. The cost to implement the RASD programs was estimated from the energy efficiency study performed by Dunsky Energy Consulting to develop, implement and administer energy efficiency programs over the 25-year period, as well as the associated cost to implement NB Power’s Smart Grid strategy. The total cost of the RASD program was projected to be $487 million on a net present value basis over the study period. It was assumed that this cost and the demand and energy reduction potential would continue at a constant level beyond the 25-year program period to represent capital replacement of at least equivalent or greater efficiency. This schedule would then have the flexibility to start anytime during the study period. This configuration was established as outlined in Figure 68.

Figure 68: Potential RASD reduction schedule

Year	MW	GWh
1	13	27
2	13	61
3	34	125
4	45	193
5	84	266
25	609	2,014

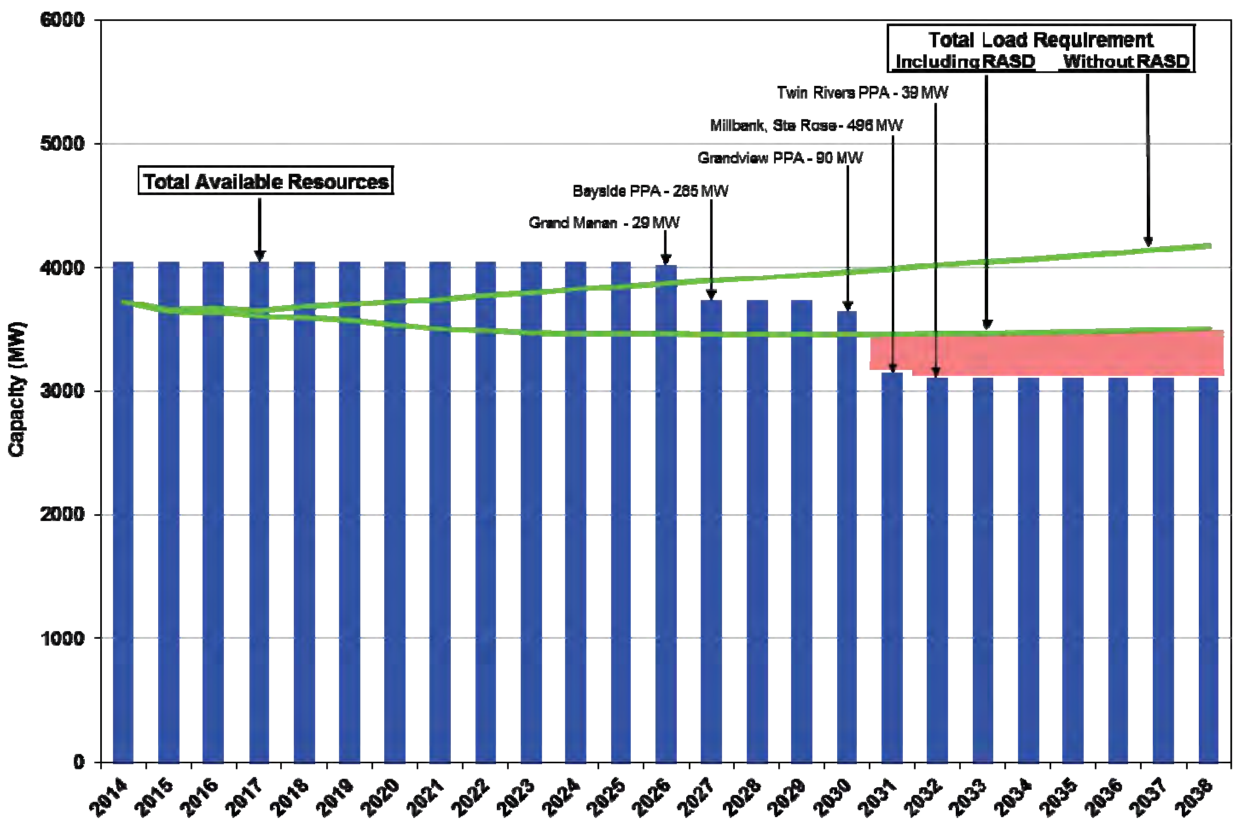
8.2.3. Integration Minimization Criteria

To determine the effect of RASD integration on the supply plan analysis, a number of issues were studied. Initially, to examine how RASD options compared with the proposed generating units in the supply plan, the dynamic programming module was used to find the least-cost plan in terms of total net present value cost. In addition, the least-cost integrated plan was evaluated in terms of average cost of service per kWh or the annual average electricity price required recovering all costs to meet in-province energy requirements. The latter allows for comparison of electricity prices and therefore shows the potential rate impact.

8.3. Final Integration Results

The integration analysis has resulted in the selection of the RASD program early in the study period. The effect on resource requirements is depicted in Figure 69. As expected, this option has deferred the requirement of new capacity.

Figure 69: Effect of including RASD on the load and resource requirements



The resulting least-cost integrated plan is outlined in Figure 70. In this plan, all of the RASD projected was selected by PROVIEW to start in 2014. The load and resource chart in Figure 69 shows new capacity requirement beginning in 2027, but with RASD and the additional capacity early in the period to meet the RPS requirement, the need for new capacity to meet the new load now has been deferred to 2031.

Figure 70: Impact of integrating RASD with supply options

In Service Date	Supply Plan	Integrated Plan
2014		RASD Program Starts Here
2020	75 MW Community Energy	75 MW Community Energy
2026		
2027	100 MW Grand Falls 89 MW Combustion Turbine (CT)	
2030	350 MW Interconnection Purchase Mactaquac Replacement	Mactaquac Replacement
2031	Millbank /Ste. Rose Life Ext.	Millbank /Ste. Rose Life Ext.
2032		
2038	89 MW CT	
NPV (2013$)	**$20,570 Million**	**$20,130 Million**
NPV (2013$) Differential Savings	**-**	**$440 Million**

The total net present value (NPV) cost shown, is expressed in 2013 Canadian dollars and includes all costs (total fuel and purchased power, new and existing O&M and new and existing capital requirements, as well as total costs for transmission, distribution and head office).[43] These costs were captured within the study period as defined between 2014 and 2038. In addition, the Integrated Plan includes the investment associated with the RASD program. This is projected to be $487 million.

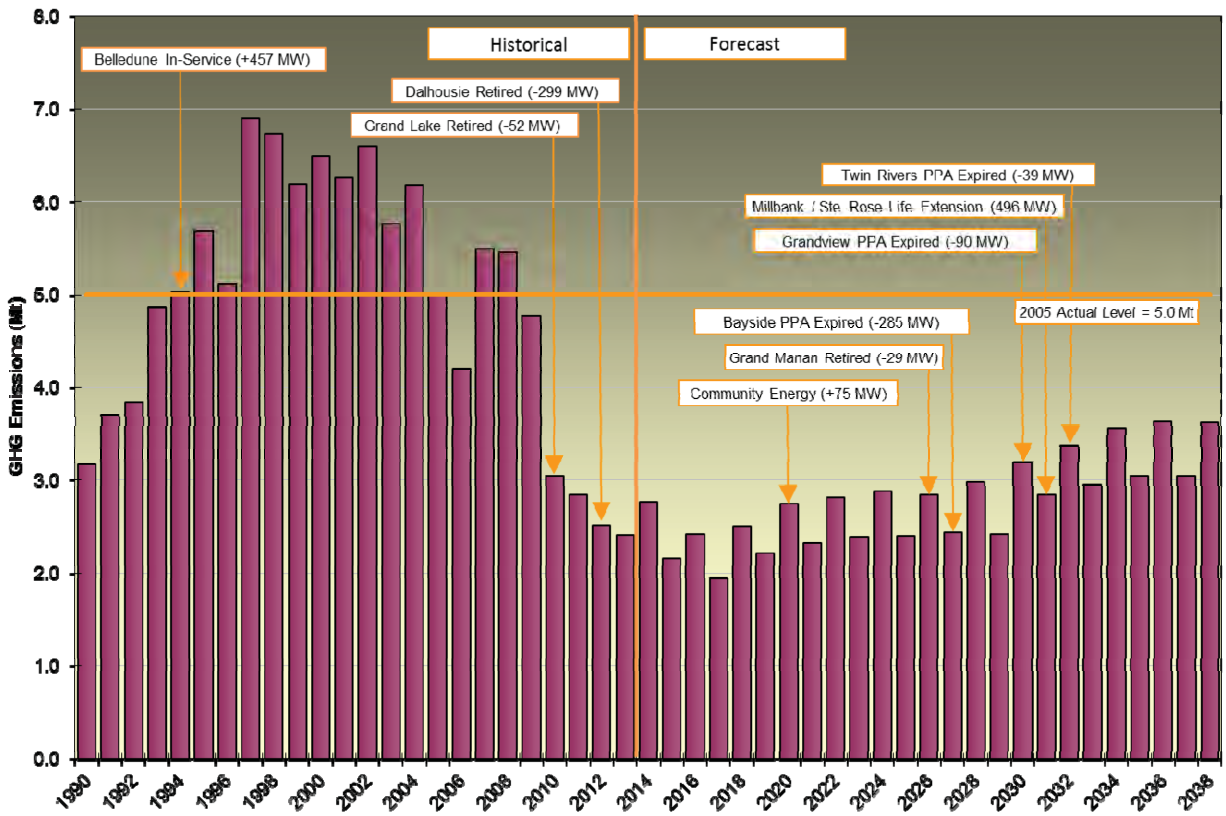
[43] With exception to costs associated with the replacement of Mactaquac expected in 2030. The replacement options and associated costs for this project are currently under review.

The Integrated Plan's net present value cost is approximately 2 per cent ($440 million) lower than that of the Supply Plan. This represents a savings of $927 million associated with the introduction of RASD and is attributable to the deferral or elimination of two combustion turbines, the firm interconnection purchase and the Grand Falls expansion project, as well as replacement fuel and purchased power savings.

Normally the PROVIEW model will select a resource option when there is a need for new capacity or a there is a need for compliance to meet regulations such as the RPS. The model could also advance a resource option based on economics. The PROVIEW model had the option to add potentially lower cost energy resource such as the Grand Falls expansion project as part of the Integrated Plan but chose not to include this option. This option was not cost effective in the Integrated Plan and also not needed to meet the RPS requirement.

The GHG emissions associated with the Integrated Plan is provided in Figure 71 and is compared to historical emissions to serve in-province load.

Figure 71: In-province GHG emissions of the Integrated Plan, compared to actual emissions

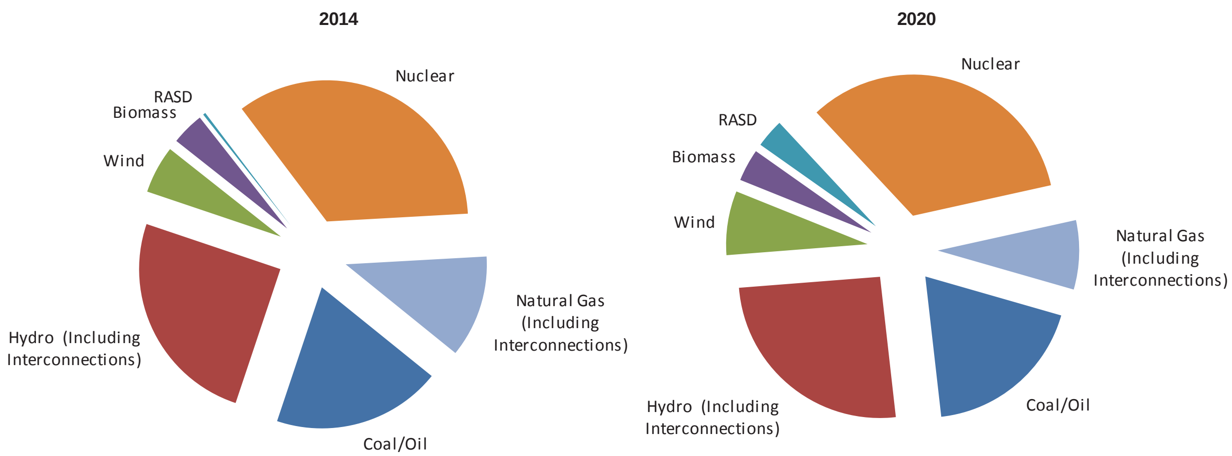


The emissions from the Integrated Plan remain below the 2005 levels and well below long-term historical levels seen in the decade starting in 1990. The emissions shown are associated with serving in-province load and do not include emissions attributable to interconnection sales.

The projected emissions starting in 2014 vary slightly on a two-year interval because of the Point Lepreau maintenance outages that occur every second year.

NB Power has built its system with consideration of fuel diversity to help reduce the risk and potential exposure to future fuel price fluctuations. In the future, new renewable resources and RASD will improve this diversity and continue to provide continued mitigation to this risk. Exposure to GHG risk is also reduced since non-emitting resources approach 75% by 2020.

Figure 72: Generation Mix



8.4. Sensitivity Analysis

Under the base assumptions, the Integrated Plan is the most economic. However, in order to assess the robustness of the Integrated Plan, it must be tested under varying key assumptions. The Integrated Plan must not only be lowest cost for a single estimate of future conditions, but must be flexible by responding well to changes in major input assumptions.

Robustness is the measure of the Integrated Plan's ability to remain the least-cost plan under changing conditions. The sensitivity analysis in this study involved re-optimization of supply options under changes to major input assumptions related to the given sensitivity. This process allowed supply options to compete once again, and allowed them to be replaced, deferred, advanced or removed in response to the changing conditions.

In general terms, sensitivity analyses investigate the effects of uncertainty on a study or model. Within the context of this IRP, sensitivity analyses determine the robustness of the Integrated Plan by identifying what source of uncertainty weighs more on the study's conclusions.

In most IRP studies, changes from the base assumptions are simply formulated as "what if" analyses, testing important input assumptions with high and low scenarios. In some instances, Monte Carlo simulation studies are then undertaken to address the issue of the likelihood of a critical input parameter occurring. However, this assumes that the probability distribution of the parameter is well behaved. Few parameters in finance or economics have well-defined probability distributions. This is especially true for parameters related to energy production and prices. In addition, full Monte Carlo simulations require intensive computation resources, compounding with each additional sensitivity parameter, leading to hundreds of simulation runs. For these reasons, this analysis has applied a knowledge-based approach where all quantifiable information is assembled and synthesized to form a reasonable upper and lower bounds of the critical parameter. The notable shortcomings of this type of analysis are the interactive effects of varying different parameters. Therefore, "stress cases" were developed that vary groups of input parameters that are linked under plausible future scenarios.

The critical supply parameters that have the most relevance in this IRP are

- capital costs,
- fuel prices,
- load forecast,
- GHG regulation and prices, and
- stress case evaluation.

8.4.1. Capital Costs

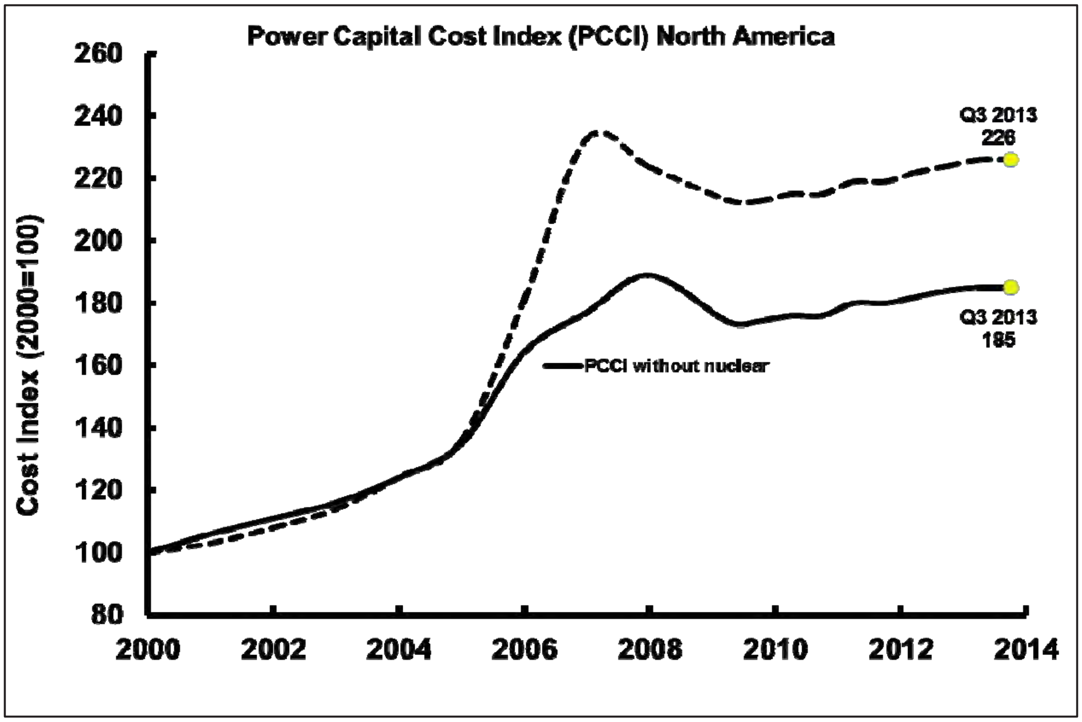
There are many factors that influence capital-related costs of projects. This study has isolated three key areas that influence NB Power:

- construction price index;
- direct capital cost risk; and
- private versus public financing.

Construction Price Index

Some of NB Power's existing generating facilities will come to their end-of-life dates during the period of this study. Significant capital construction will be required to replace the aging infrastructure. The electric utility construction price index is commonly used in this industry to reflect costs for capital construction. The index is projected to escalate at 4 per cent per year, based on Figure 73 below.

Figure 73: Historical Construction Price Index



See Section 3.8.3 (The Construction Price Index) for additional information. Figure 74 shows the effects of varying construction price indices of 3 to 5 per cent.

Figure 74: Cost summary for construction price indices

	Integrated Plan (4 per cent)	Construction Price Index of 5 per cent	Construction Price Index of 3 per cent
NPV Cost (2013$)	$20,130 Million	$20,137 Million	$20,124 Million
Additional Cost from the Integrated Plan	-	+$7 Million	-$6 Million

The Integrated Plan remains the least-cost expansion plan in all cases.

Direct Capital Cost Risk

As with any capital project, there are risks of capital cost overruns. Power plant costs are relatively well defined because many times the components are large and often built offsite by the manufacturer. These component manufacturers are very competitive, and fixed-price contracts are normally specified. Therefore, a range of ±10 per cent was considered. Figure 75 provides the result of this sensitivity applied to the Integrated Plan.

Figure 75: Cost summary of capital cost risks

	Integrated Plan	Capital Costs +10 per cent	Capital Costs -10 per cent
NPV Cost (2013$)	$20,130 Million	$20,134 Million	$20,126 Million
Additional Cost from the Integrated Plan	-	+$4 Million	-$4 Million

The Integrated Plan remains the least-cost expansion plan in both sensitivity cases.

Private versus Public Financing

The weighted average cost of capital (WACC) in the private sector has been assumed in this study at approximately 8.33 per cent, while the WACC assumed for public sector development in New Brunswick is 5.65 per cent (this rate was applied throughout this report). The cost of capital in the public sector is lower due to government backing and no embedded return on equity. Applying the higher WACC rate would increase the cost of all supply options. For additional information, refer to Section 5.1.2 (Private Versus Public Financing). Figure 76 shows the effect of applying the private financing assumptions.

Figure 76: Cost summary for private versus public financing

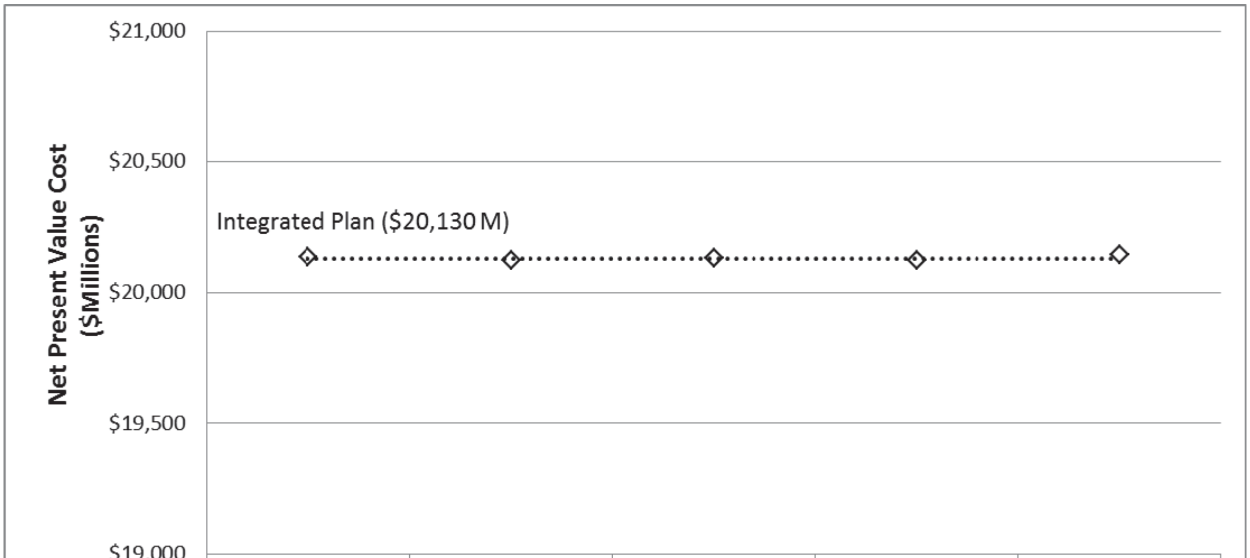
	Integrated Plan (WACC = 5.65 per cent)	Private Financing (WACC = 8.33 per cent)
NPV Cost (2013$)	$20,130 Million	$20,144 Million
Additional Cost from the Integrated Plan	-	+$14 Million

The Integrated Plan remains the least-cost expansion plan under this sensitivity.

Summary of Capital-Related Costs

The results of the capital-related cost sensitivities are illustrated in Figure 77. The Integrated Plan demonstrates its robustness against capital-related changes with very little variation in costs.

Figure 77: Sensitivities for capital related costs



	Construction Price Index 5 per cent	Construction Price Index 3 per cent	Capital Costs +10 per cent	Capital Costs -10 per cent	WACC 8.33 per cent
Integrated Plan	$20,130.0	$20,130.0	$20,130.0	$20,130.0	$20,130.0
Sensitivity	$20,137.0	$20,124.0	$20,134.0	$20,126.0	$20,144.0
Variance	$7.0	-$6.0	$4.0	-$4.0	$14.0

8.4.2. Fuel Prices

Fuel is one of NB Power's largest expenses. The industry has experienced extreme volatility in fuel prices in recent years. Any long-term plan must address the risk of the cost of the fuels that will be used.

Natural Gas
Natural gas is a premium fuel that is expected to be abundantly available into the future. Compared to other fuels such as nuclear and oil, natural gas has a high level of public acceptance. In the future, it is expected that natural gas will be the fuel of choice for electricity production. Some of the factors that may affect the price of natural gas, both in the short and long term, are outlined in Figure 78.

Figure 78: Pressures on natural gas prices

Natural Gas	Downward Price Pressure	Upward Price Pressure
Short-term (< 5 years)	• Advent of local shale gas • Liquefied Natural Gas (LNG) surplus • Struggling economy in North America • Pipeline infrastructure coming on-stream	• CO2 legislation • Strong Asian economy • Shale gas regulations • Higher transportation (pipeline) cost due to lower sales • Shut-in production to match demand
Long-term (> 5 years)	• Strong shale gas performance • New regulatory oversight on over the counter (OTC) trades	• Shale gas performance lower than expected • Recovering world economy • Reduced exploration in short term will impact long term prices • Increased market penetration

There is a strong correlation between the price of natural gas and the market price of electricity. This leads to the conclusion that the sensitivity analyses for natural gas prices and the market price of electricity should not be done in isolation. Therefore, sensitivities of +25 and -25 per cent were applied to natural gas and electricity market prices concurrently for this study.

Figure 79: Cost summary of natural gas and market price risk

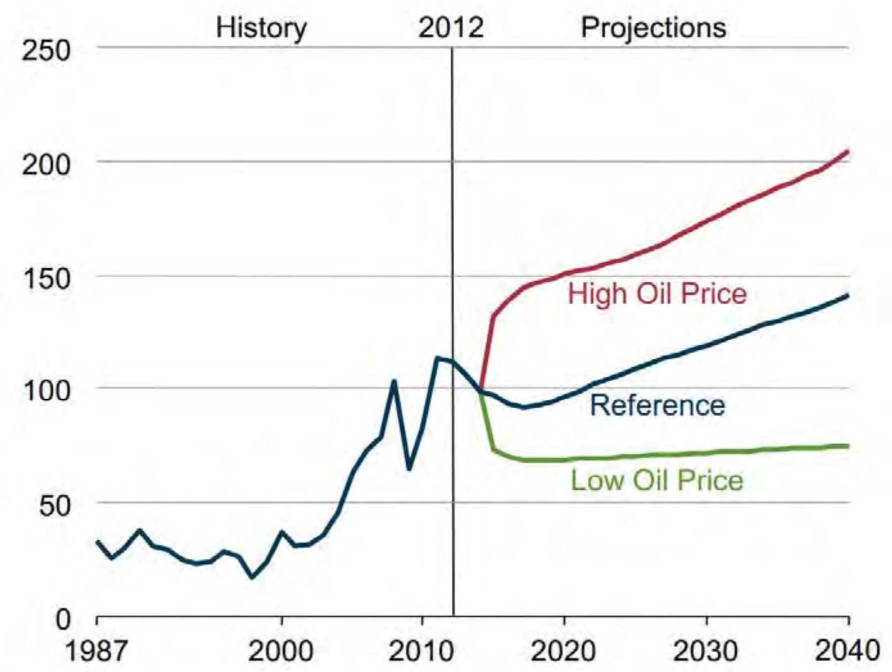
	Integrated Plan	Natural Gas & Market Prices +25 per cent	Natural Gas & Market Prices -25 per cent
NPV Cost (2013$)	$20,130 Million	$20,665 Million	$19,481 Million
Additional Cost from the Integrated Plan	-	+$535 Million	-$649 Million

The Integrated Plan remains the least-cost expansion plan under both of these sensitivity cases.

Heavy & Light Fuel Oil

Heavy fuel oil (HFO) is utilized at NB Power's Coleson Cove generating station. However, the utilization of heavy fuel oil is relatively low due to high prices and relatively high heat rates of current and new, oil-fired thermal plants. Therefore, oil is not considered to be an economic option for electricity generation in the future. It is expected that because of geopolitical pressures and the lack of price elasticity, future prices for oil will continue to be volatile and unpredictable. A reasonable sensitivity for heavy fuel oil is ±50 per cent which is consistent with predictions given by the U.S. Energy Information Administration (EIA),[44] as shown in Figure 80.

Figure 80: Average annual Brent spot crude oil prices in three cases, 1987-2040 (2012 dollars per barrel)



For the oil price sensitivity analysis, a constant ±50 per cent variation was applied to all heavy fuel oil and light fuel oil prices. Figure 81 shows the effect of varying fuel prices on the Integrated Plan.

[44] U.S. Energy Information Administration. (2014) AEO2014 Early Release Overview. Retrieved from: http://www.eia.gov/forecasts/aeo/er/pdf/0383er(2014).pdf

Figure 81: Cost summary of heavy and light fuel oil price risk

	Integrated Plan	Heavy/Light Fuel Oil prices +50 per cent	Heavy/Light Fuel Oil prices -50 per cent
NPV Cost (2013$)	$20,130 Million	$20,201 Million	$19,914 Million
Additional Cost from the Integrated Plan	-	+$71 Million	-$216 Million

The Integrated Plan remains the least-cost expansion plan under both of these sensitivities. It is also noteworthy that NB Power is less sensitive to upward movement in oil prices, and the magnitude of the oil sensitivity is less than the natural gas and market price sensitivity.

Coal

Coal is a relatively low cost fuel used at NB Power's existing generation asset located in Belledune. Because of the relatively low price, there is little room for downward coal price movement. Also, when considering the associated GHG issues, price increases are unlikely. Due to new regulations regarding coal, no new coal plants were considered in this study. Therefore, a sensitivity of the fuel price of coal was not considered necessary. It is expected that the sensitivities around GHG prices will have a large impact on existing coal generation.

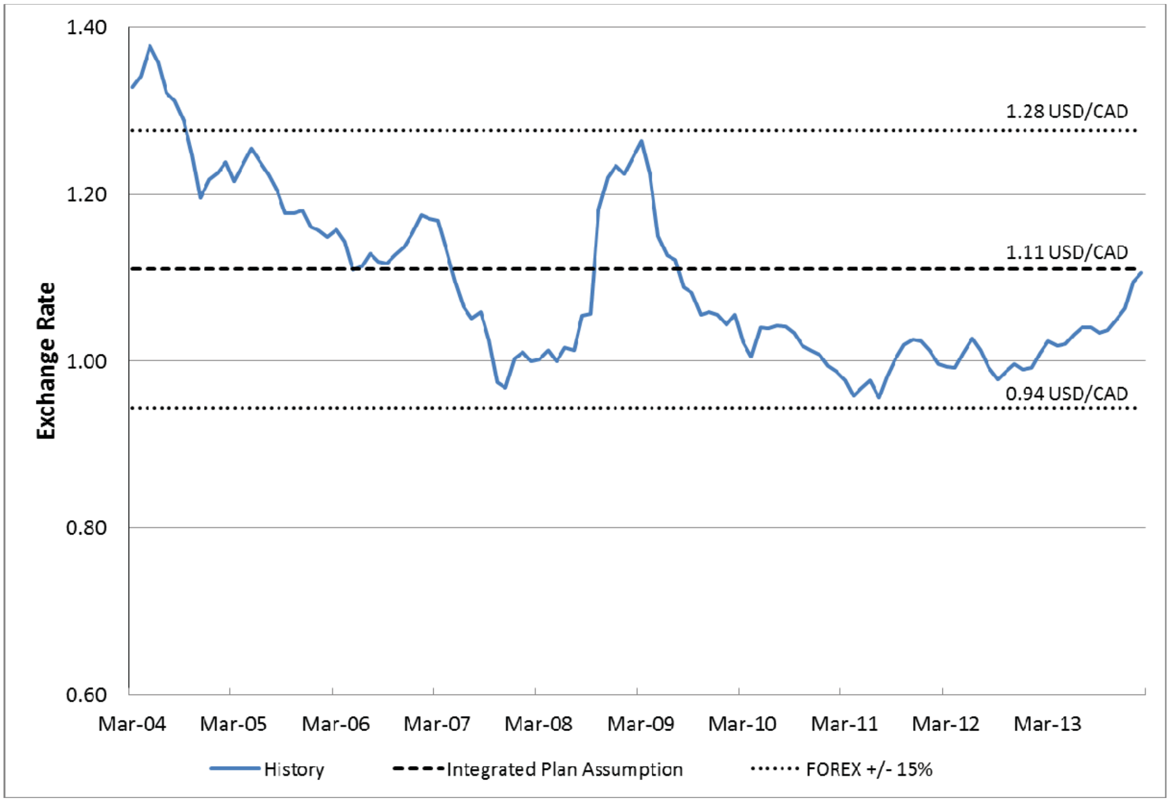
Nuclear

The price of nuclear fuel has historically remained stable and lower than fossil fuel prices. There is no indication that this will change. Therefore, a sensitivity of the fuel price of nuclear was not considered necessary.

Foreign Exchange Rates

Most fuels purchased by NB Power are priced based on the US market, and therefore priced in US dollars (USDs). The exchange rate between the Canadian dollar (CAD) and the USD is a major risk for NB Power. The Integrated Plan assumes an exchange rate of 1.11 USD/CAD (i.e., 1USD = 1.11CAD). The historical foreign exchange rate (FOREX) is shown in Figure 82.

Figure 82: 10-year historical foreign exchange rate and forecasts



The foreign exchange rate affects not only fuel prices, but also electricity market prices. Therefore, this sensitivity was applied to all fuels and all market-based transactions. The results are summarized below in Figure 83.

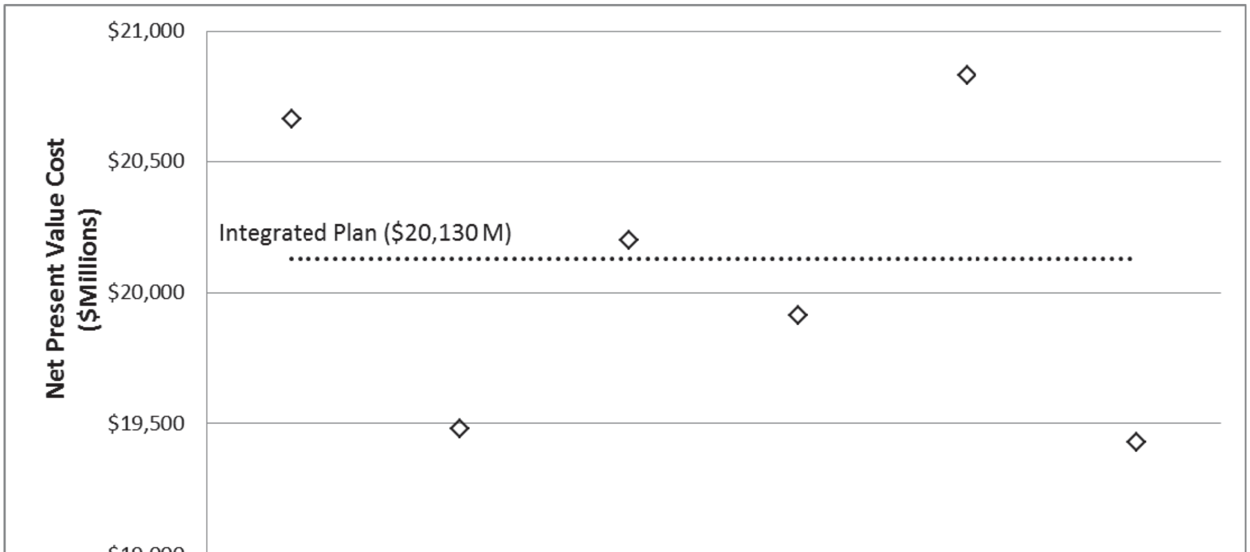
Figure 83: Cost summary of foreign exchange

	Integrated Plan	FOREX (USD/CAD) +15 per cent	FOREX (USD/CAD) -15 per cent
NPV Cost (2013$)	$20,130 Million	$20,832 Million	$19,428 Million
Additional Cost from the Integrated Plan	-	+$702 Million	-$702 Million

The Integrated Plan remains the least-cost expansion plan under both of these sensitivity cases.

The fuel price sensitivities are summarized graphically in Figure 84.

Figure 84: Cost summary for fuel price variation



	Natural gas & Market Prices +25 per cent	Natural gas & Market Prices -25 per cent	Heavy & Light Fuel Oil Prices +50 per cent	Heavy & Light Fuel Oil Prices -50 per cent	FOREX +15 per cent	FOREX -15 per cent
Integrated Plan	$20,130	$20,130	$20,130	$20,130	$20,130	$20,130
Sensitivity	$20,665	$19,481	$20,201	$19,914	$20,832	$19,428
Variance	$535	-$649	$71	-$216	$702	-$702

The expansion plan is very robust against fuel price changes. However, there is significant risk to NB Power associated with fuel price and foreign exchange uncertainty. NB Power is much more sensitive to natural gas and market prices than oil prices.

8.4.3. Load Forecast

This study has used the most recent NB Power load forecast completed in January 2014. A 95 per cent confidence interval was used for the high and low forecasts, based on statistical analyses of historical and future trends.

Figure 85 illustrates the impact on electricity requirements in New Brunswick. This chart also shows historic load within New Brunswick.

Figure 85: Possible changes to the baseline load forecast (before RASD reductions)

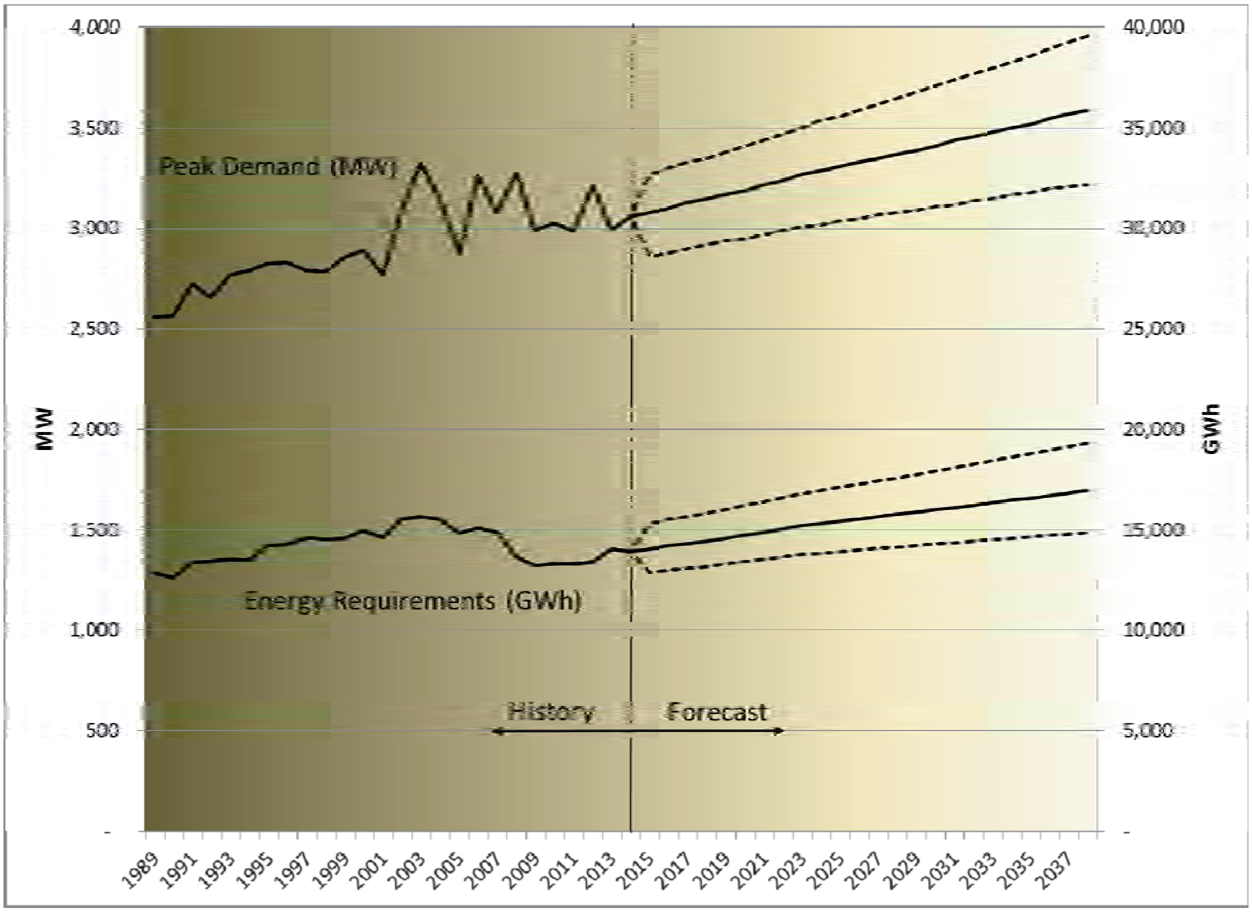


Figure 86: Expansion Plans for high- and low- load forecast cases

	Integrated Plan	High Load Forecast	Low Load Forecast
2014	RASD Program Starts	RASD Program Starts	RASD Program Starts
2020	75 MW Community Energy	75 MW Community Energy	75 MW Community Energy
2030	Mactaquac Replacement	Mactaquac Replacement 412 MW NGCC	Mactaquac Replacement
2031	Millbank / Ste. Rose Life Ext.	Millbank / Ste. Rose Life Ext.	Millbank / Ste. Rose Life Ext.
2038			
NPV Cost (2013$)	$20,130 Million	$21,657 Million	$19,023 Million
Additional Cost from the Integrated Plan		+$1,527 Million	-$1,107 Million

The additional load requirement under the high load forecast advances the need for new generation capacity to 2030. In all load sensitivity plans, the options chosen are similar. The low load forecast requires one less NGCC unit during this period. In the high load forecast case, the higher energy requirements drive up fuel and purchased power costs, and additional demand requirements require an additional NGCC. The low load forecast sees savings for the same reason, but with no changes in the expansion plan compared to the Integrated Plan.

NB Power's load forecast and requirements are very sensitive to changes in industrial loads. The addition of a 100+ MW large industrial customer can occur within a short time frame of less than five years. Therefore, it is important that NB Power's system be ready and able to respond to such load increases. Figure 87 shows the impacts of adding a high load factor (87 per cent) 115 MW industrial customer in 2019.

Figure 87: Cost adding an additional 115 MW of Industrial load

	Integrated Plan	Addition of 115 MW Industrial Load
NPV Cost (2013$)	$20,130 Million	$20,629 Million
Additional Cost from the Integrated Plan	-	+$499 Million

The need for new capacity is not required within the study period. The Integrated Plan is robust under this sensitivity and has sufficient capacity to accommodate this additional industrial load.

8.4.4. GHG Regulation and Prices

As indicated in Section 3.5 (Environmental and Sustainability Considerations), the possible GHG regulation remains very complex with many uncertainties. A cap and trade system was not modelled in this study because of the many unknowns, and because the federal government has chosen to regulate GHG through performance standards; however, this study has assumed standard performance metrics for existing and new fossil units, to which various carbon prices were then applied.

Also mentioned in Section 3.5 were some of the studies that have been published predicting the price of carbon, including:

- the federal government's Turning the Corner Plan in March 2008. It modelled the price of carbon to be at $15/tonne in 2010, 2011 and 2012, $20/tonne in 2013, then escalating at gross domestic product (GDP) until 2020 when the price would have full market exposure and is predicted to be $65/tonne;
- a report by the National Round Table on the Environment and the Economy (NRTEE) predicted that the price of carbon would need to be $100/tonne by 2020 if the Canadian government's targets were to be achieved; and
- a report by the U.S. Environmental Protection Agency (EPA), based on the Waxman-Markley Bill, estimated a carbon price of $20CDN/tonne in 2010 escalating to $25CDN/tonne by 2020.

The variability of carbon prices in existing markets and current studies are significant. After much evaluation, it was felt that the most likely base case for carbon prices would only be applied above certain thresholds, also known as an allocation or cap. It is expected that NB Power would maintain carbon levels below these limits and therefore the applied carbon price would be zero. However, because of the risk associated with carbon prices and uncertainty with respect to allocation, two price levels were examined, and these prices were applied to the full amount of GHGs emitted. A high case would represent the numbers similar to those outlined in the NRTEE report. A medium case would represent a balance of the numbers outlined in the U.S. EPA report and the Turning the Corner Plan.

Figure 88: GHG price projections

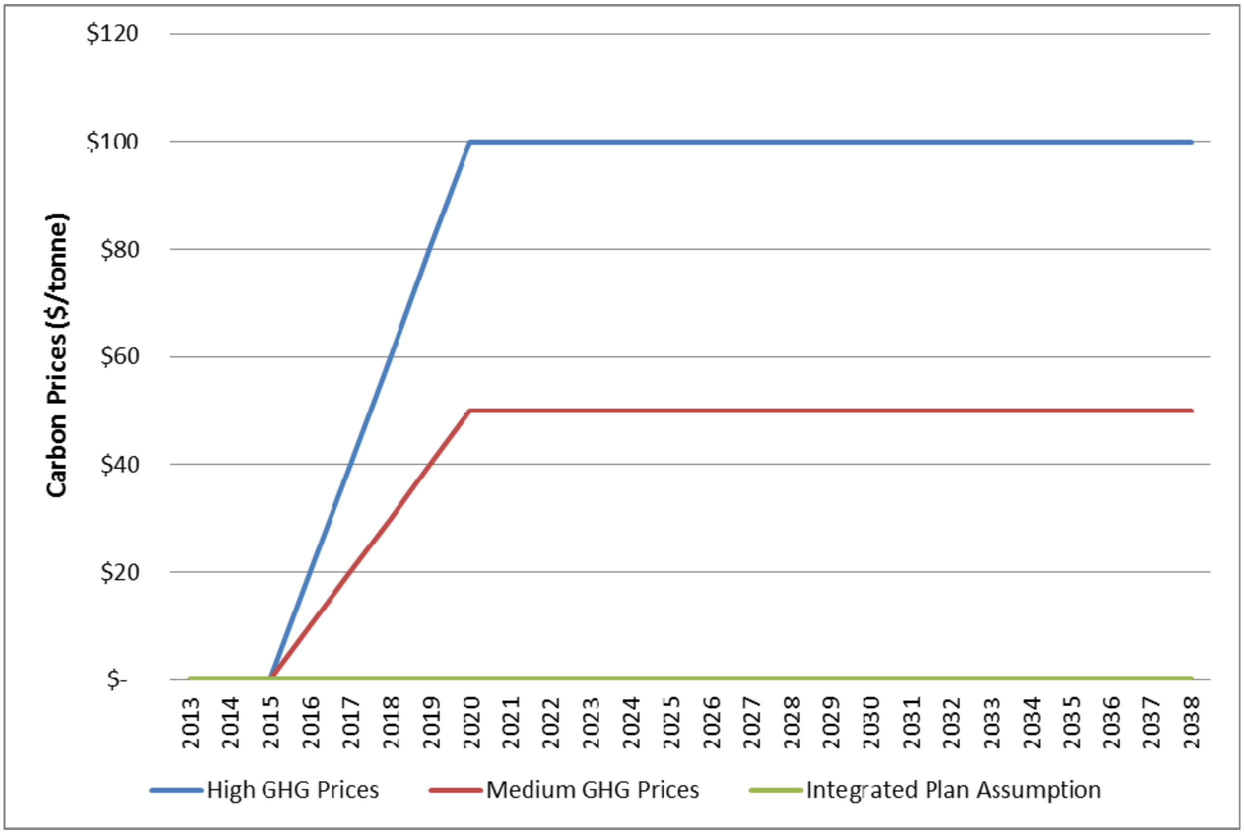


Figure 89: Cost summary of varying GHG prices

	Integrated Plan (no GHG costs)	Medium GHG prices	High GHG prices
Net Present Value Cost ($2013)	$20,130 Million	$20,944 Million	$21,312 Million
Additional Cost from the Integrated Plan	-	+$814 Million	+$1,182 Million

Overall, this sensitivity has significant impact on the cost of the Integrated Plan. Under the medium level of carbon price sensitivity, the Integrated Plan continues to be the least-cost plan for the GHG price sensitivity. In the high GHG price, the least-cost expansion plan includes building a 100 MW hydro unit at Grand Falls in 2020.

As mentioned, because the federal government has chosen to regulate GHG's through performance standards, it is not expected that a cap and trade system will be introduced. However, this sensitivity shows that the impact can be significant depending on price of carbon and the allocation assumptions. The sensitivity shows that NB Power's cost of service will increase, and will impact electricity rates. This has a potential cascading effect through the potential loss of load, particularly in the industrial sector, which may result in stranding NB Power assets.

8.4.5. Scenario Evaluation

The sensitivity analyses have indicated the robustness of the Reference Plan under a wide range of changing conditions. However, the sensitivities have assumed that each variable change would occur one at a time and in isolation from one another. Further analysis was then performed using multiple sensitivities to once again determine the robustness of the Integrated Plan. Two different scenarios were developed: one assumed a booming North American economy, the other a local New Brunswick-specific economic boom. Various sensitivities were combined as shown in Figure 90.

Figure 90: Scenario analysis assumptions

	North American Economic Boom	Local Economic Boom
Natural Gas Prices	High (+25 per cent)	Low (-25 per cent)
Oil Prices	High (+50 per cent)	no change
Market Prices	High (+25 per cent)	no change
Construction Price Index	High (5 per cent)	no change (4 percent)
Green House Gas Prices	Medium ($50/tonne by 2020)	no change
Load Forecast	no change	Addition of 115 MW Industrial Load
Exports	no change	Increased export opportunity

Figure 91: Cost to the Integrated Plan associated with various scenarios

	Integrated Plan	North American Economic Boom	Local Economic Boom
Net Present Value Cost ($2013)	$20,130 Million	$21,898 Million	$20,346 Million
Additional Cost from the Integrated Plan	-	+$1,768 Million	+216 Million

Under the North American Economic boom case, the expansion plan includes a 100 MW hydro unit at Grand Falls in 2020. This is due to high fuel and market prices as well as GHG costs. In the Local Economic Boom case, no new requirement for supply is needed from the Integrated Plan.

It will be important to continue monitoring fuel prices and the regulatory requirements related to GHG emissions. Having an appropriate mix of generation, and diversity of supply, balanced with long-term strategies to mitigate these risks, will become increasingly important.

9. CONCLUSION

The results of this IRP study provide information regarding the strategic course of action that NB Power should consider to meet its future resource needs. The following statements reflect the IRP results.

1. New capacity will not be required until 2027 or later.
2. The most cost-effective future resource mix is composed of renewable resources in the initial period to meet the RPS requirement, with continued emphasis on RASD.
3. The peaking resources can be provided most economically with a combination of RASD, peak interconnection purchases and combustion turbines.
4. The amount of cost-effective RASD projected to be achievable by 2020 is 184 MW and 443 GWh, and grows to 609 MW and 2014 GWh by 2038.
5. In order to achieve sufficient RASD capacity to avoid construction of new combustion turbines, the current level of RASD should continue with increasing effort over the long-term.
6. GHG levels to meet in-province load remain below the 2005 historical level of approximately 5 million tonnes.
7. Base and intermediate load requirements required to meet end of life of existing facilities are most economically achieved by new renewables and RASD.
8. Millbank and Ste. Rose life extension is the most economic choice for continued peak load requirements after the current retirement date.
9. Replacement of the Mactaquac Generating Station is anticipated by 2030 to respond to the ongoing Alkali-Aggregation Reaction (AAR) and related concrete expansion. Further study will be required to determine the optimum replacement option and to fully assess the economics of this project.
10. The future conditions that may have the most influence on total costs are fuel and market prices and the construction price index, as well as GHG pricing.
11. Continued examination of new and innovative technologies will be necessary to ensure the latest information and options are available, and to ensure a diverse mix of generation in the long term.
12. RASD will help reduce exposure to changes in future assumptions.

In summary, the strategic direction recommended over the immediate term is:

- Initiation of a community energy program to meet the RPS;
- Continuation of RASD programs with increased development in the long-term; and
- Continuation of technical work with regards to new generation options that might be viable in New Brunswick, especially options from renewable resources.

10. APPENDICES

Appendix 1: List of assumptions for IRP
Appendix 2: Fuel and Market Price Forecast – Reference Case
Appendix 3: Project and Operating Cost Parameters
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Appendix 10: Stakeholder Exit Survey
Appendix 11: NB Power Response to Stakeholder Input
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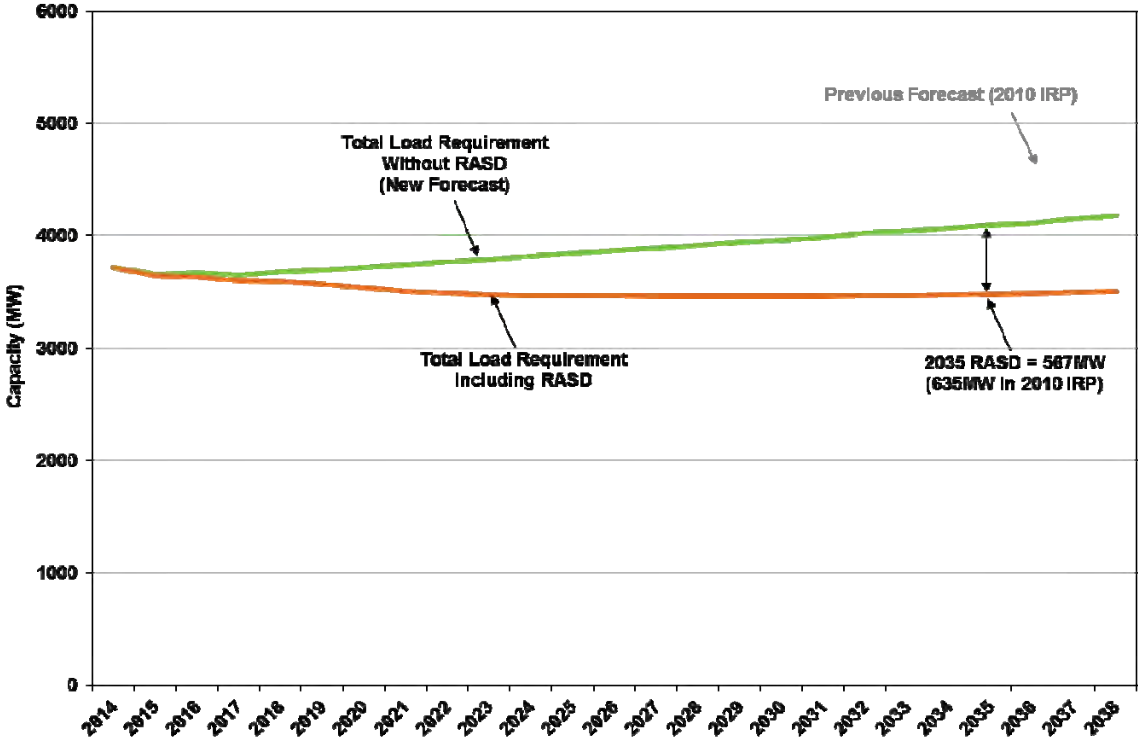
Appendix 13: Glossary and Abbreviations

Appendix 1: List of assumptions for IRP

- **General Inflation**
  - Assumed 2.0% per year throughout the period.

- **Load Growth**
  - Based on NB Power's most recent ten-year Load Forecast.
  - Embedded RASD forecast removed from NB Power load forecast.
  - New RASD projection determined from the IRP analysis.
  - Planning reserve requirement of 20% or the largest contingency was applied.



- **RASD Analysis**
  - RASD program options identified with the assistance of Dunsky Energy Consultants.
  - Comprehensive screening analysis of all options completed by Dunsky and NB Power with participation from Efficiency New Brunswick, Saint John Energy, Edmundston Energy, Perth-Andover Light Commission, NB Department of Energy and NB Department of Environment.
  - RASD programs that passed the comprehensive screening analysis are made available to compete and integrate with supply options.
  - Energy efficiency and demand response program costs have been updated to reflect the three-year energy efficiency plan and RASD budgets.

- **Fuel and Purchased Power**
  - Fuel and market price forecast in the short-term based on NB Power projections incorporated into the 2014/15 budget.
  - Long-term fuel and market price projections based on forecasts and analysis provided by PLATTS, an external consultant specializing in this area.
  - Foreign exchange rates based on Bank of Canada Foreign Exchange Forward Curve in the short term (3 years). In the long term, foreign exchange rates assumed at an average of the short-term curve.
  - Energy production from all generating units is determined by economic dispatch to meet in-province load requirements.
  - Short-term interconnection purchases are made available when generating unit dispatch prices exceed forecasted market prices.

- **New Supply**
  - New supply options and costs refreshed by Hatch Engineering in July 2013.
  - Supply options included conventional and renewable alternatives.
  - Screening analysis performed using levelized cost methodology to determine cost effectiveness and feasibility.

- **Existing Plant and Power Purchase Agreements End of Life**
  - Based on current greenhouse gas regulation for coal units, Belledune generating station allowable operating life will be 50 years (end of life in 2043).
  - Coleson Cove generating station current operating life of April 2030 has been extended to April 2040.
  - Additional capex and O&M have been included to life extend Belledune and Coleson Cove.
  - The end of operating life for remaining generating assets are assumed as follows:
    - Millbank and Ste. Rose – November 2055 (25 year life extension option is made available and based on March 2013 discussion paper by Generation Engineering)
    - Point Lepreau – December 2039
    - Existing hydro facilities assumed to be replaced in kind including Mactaquac
    - Note: Mactaquac replacement study and its full impact on the system will be done using the IRP as the basis.

▪

- PPAs with Bayside and Grandview extended by 5 years to March 2026 and November 2029 respectively.
- Twin Rivers Biomass PPA terminated in 2031.
- Wind PPAs renewed for an additional term at reduced prices (25% reduction of new costs).

- **Greenhouse Gas Regulation and Prices**
  - Proposed federal performance standards applied to new and existing refurbished coal plants.
  - Existing coal plants are allowed to operate for 50 years from in-service without penalty.
  - Performance standards dictate carbon capture and sequestration for all new and existing refurbished facilities beyond a 50-year life.
  - No further regulation proposed at this time for other thermal plants.

- **Major Capital Expenditures**
  - Moncton loading project is not included in the capital spending forecast but under review.
  - Grand Falls expansion is not required to meet RPS requirements. In service costs are estimated at approximately $330 million (2013$). This project will be selected if it is an economic supply choice.
  - In-Service costs for all Mactaquac options yet to be determined. The IRP reference case assumes Mactaquac capacity and energy is replaced in kind or equivalent.
  - The major capital costs to extend the lives of Belledune and Coleson Cove were estimated to be $83 million and $143 million (2013$) respectively. These figures were based on very preliminary engineering estimates. An asset optimization study will be conducted to update these estimates.
  - Capital and O&M estimates for all other generating supply options provided by Hatch Engineering.
  - Construction price index for all generating supply options pegged at 4% per year.

- **Export Sales**
  - Revenues from MECL continue for participation agreement in Point Lepreau until the end of its life – based on future forecasted costs.
  - Other export load currently held for MECL and Maine was assumed to be maintained.
  - Other opportunity exports were modelled or estimated based upon margins currently generated from existing export load and changes in plant availability in the future.

- **Operations, Maintenance and Administration Costs**
  - Long-term costs escalate at general inflation of 2% per year.
  - OM&A costs for Point Lepreau were modelled to reflect biennial outages. Higher costs were assumed towards the end of life of the Point Lepreau facility to reflect employee retention.
  - New plants (CT's and natural gas facilities) have operating costs provided by Hatch Engineering, and include OM&A and capital. Amounts for ongoing capital reinvestments have also been included in OM&A.

- **Amortization and Decommissioning**
    - The Belledune and Coleson Cove plant costs are amortized over their existing book life and additional expenditures and decommissioning adjustments required to extend the life of the plants were recovered over the extension period.
    - The costs of future natural gas power plants and combustion turbines were amortized over a 25-year period.

- **Deferral Accounts**
    - The Point Lepreau Regulatory Deferral is recovered over the life of the plant.

- **Financing Assumptions**
    - All existing and new supply options assume public financing.
    - Long term financing rate of 5.65% was assumed; 5.0% for debt financing plus the government guarantee fee of 0.65%. This provided for an equivalent weighted average cost of capital (WACC) of 5.65%.
    - An earnings rate of 5% was assumed for the trust funds and the sinking fund held.
    - A discount rate equivalent to the WACC of 5.65% was assumed for all NPV analysis.
    - A discount rate of 5% was assumed for the decommissioning and UFM liabilities.

- **Ratemaking Assumptions**
    - A ten-year debt:equity target of 80:20 was assumed to be achieved by 2021.
    - Beginning in 2013/14, annual rate increases of 2% were assumed to achieve the debt:equity target by 2021.
    - The accounting implications of IFRS, particularly related to the treatment of regulatory deferrals and charges, were not factored into the model.
    - Transmission rate filing is planned prior to October 1, 2014 as per Electricity Act and every three years thereafter.

Appendix 2: Fuel and Market Price Forecast

	HFO C$Nom /MMBtu	LFO C$Nom /MMBtu	Nat Gas Average C$Nom /MMBtu	Coal Blend C$Nom /MMBtu	Coal (Imp) C$Nom /MMBtu	Pet-coke C$Nom /MMBtu	Biomass C$Nom /MMBtu	Nuclear C$Nom /MMBtu	Mass Hub C$Nom /MWh
2014	$15.81	$22.44	$10.14	$4.54	$5.09	$3.61	$4.10	$0.47	$75.55
2015	$15.80	$22.43	$9.82	$4.18	$4.77	$3.19	$4.22	$0.46	$66.18
2016	$15.72	$22.33	$9.21	$4.12	$4.75	$3.06	$4.34	$0.46	$60.62
2017	$15.62	$22.20	$8.42	$4.20	$4.87	$3.07	$4.44	$0.46	$56.23
2018	$15.69	$22.27	$8.65	$4.22	$4.89	$3.09	$4.54	$0.47	$54.02
2019	$16.01	$22.73	$8.89	$4.27	$4.94	$3.12	$4.64	$0.49	$56.27
2020	$16.38	$23.25	$9.00	$4.31	$5.00	$3.15	$4.76	$0.51	$57.67
2021	$16.80	$23.84	$9.01	$4.37	$5.07	$3.20	$4.88	$0.53	$58.44
2022	$17.23	$24.43	$9.13	$4.43	$5.14	$3.24	$5.01	$0.55	$59.25
2023	$17.68	$25.06	$9.25	$4.49	$5.20	$3.28	$5.12	$0.57	$60.95
2024	$18.10	$25.65	$9.24	$4.55	$5.28	$3.33	$5.24	$0.59	$61.14
2025	$18.49	$26.20	$9.38	$4.62	$5.35	$3.38	$5.35	$0.61	$62.03
2026	$18.82	$26.67	$9.41	$4.69	$5.44	$3.43	$5.46	$0.64	$61.32
2027	$19.23	$27.25	$9.57	$4.77	$5.52	$3.49	$5.58	$0.66	$62.63
2028	$19.56	$27.72	$9.70	$4.84	$5.61	$3.54	$5.69	$0.68	$63.25
2029	$19.91	$28.22	$9.87	$4.92	$5.70	$3.60	$5.81	$0.71	$64.65
2030	$20.19	$28.63	$10.02	$5.00	$5.80	$3.66	$5.93	$0.74	$66.36
2031	$20.54	$29.13	$10.22	$5.08	$5.89	$3.72	$6.06	$0.77	$69.22
2032	$20.93	$29.69	$10.37	$5.16	$5.98	$3.78	$6.20	$0.80	$70.85
2033	$21.31	$30.23	$10.56	$5.25	$6.08	$3.84	$6.34	$0.83	$73.09
2034	$21.69	$30.78	$10.72	$5.33	$6.18	$3.90	$6.48	$0.86	$74.57
2035	$22.08	$31.33	$10.89	$5.42	$6.28	$3.96	$6.62	$0.89	$76.07
2036	$22.47	$31.89	$11.05	$5.50	$6.38	$4.03	$6.77	$0.93	$77.61
2037	$22.87	$32.47	$11.22	$5.59	$6.48	$4.09	$6.92	$0.97	$79.18
2038	$23.28	$33.05	$11.38	$5.68	$6.58	$4.15	$7.07	$1.00	$80.78

Appendix 3: Project and Operating Cost Parameters

Table 1: Public Funding Scenario (Base Case)

							Levelized Cost of Electricity - LCOE ($/MWh)						
								Operating Costs					
Project	Capacity (MW)	Capacity Factor (%)	In-Service Capital Cost (2013 $k)	In-Service Capital Cost ($/KW)	Expected Life (Years)	Representative Heat Rate (Btu/KWh)	Capital	Fuel	Variable O&M	Fixed O&M	Total Operating (before income taxes)	Income Taxes	Total LCOE
Simple Cycle Gas Turbines - High Efficiency	100	5.0%	137,901	1,380	25	8,689	238.40	83.27	4.67	35.42	123.36	0.00	361.75
Simple Cycle Gas Turbines - Mid Efficiency	89	5.0%	103,054	1,158	25	10,735	199.98	102.88	16.36	29.88	149.13	0.00	349.10
Large Combined Cycle Gas	412	80.0%	642,387	1,559	25	5,997	16.83	57.47	3.51	2.29	63.28	0.00	80.11
Small Combined Cycle Gas	281	80.0%	483,638	1,721	25	6,109	18.58	58.55	4.00	3.04	65.59	0.00	84.17
LM6000 Combined Cycle	120	80.0%	227,962	1,900	25	6,552	20.51	62.79	4.12	3.16	70.08	0.00	90.58
LM6000 Combined Cycle with Cooling Tower	120	80.0%	228,252	1,910	25	6,592	20.62	63.18	4.12	3.16	70.46	0.00	91.08
Microturbines	1	80.0%	3,843	4,133	25	6,100	44.61	128.95	27.27	9.51	140.22	0.00	184.83
Natural Gas Fuel Cells	1	80.0%	8,967	8,967	20	7,980	108.41	164.43	0.00	48.51	206.36	0.00	314.77
Biomass Combined Heat and Power	14	80.0%	75,930	5,424	25	8,680	58.54	43.90	4.73	9.51	58.14	0.00	116.68
Biomass Bubbling Fluidized Bed	50	80.0%	231,103	4,622	35	13,500	43.64	72.83	7.06	20.14	100.03	0.00	143.67
Municipal Solid Waste (MSW)	50	80.0%	462,206	9,244	35	18,000	87.28	0.00	11.23	75.99	87.22	0.00	174.49
Enhanced Geothermal Energy	25	80.0%	157,746	6,310	30	0	62.98	0.00	31.22	20.14	51.36	0.00	114.34
Compressed Air Energy Storage	100	40.0%	166,484	1,665	25	4,500	35.94	43.13	77.26	3.74	124.12	0.00	160.06
Nuclear	1,100	80.0%	6,984,644	6,350	30	11,000	63.38	6.84	0.25	16.04	23.13	0.00	86.51
Wind (Small Farm)	10	35.0%	26,862	2,686	20	0	74.23	0.00	11.72	30.59	42.31	0.00	116.54
Wind (Large Farm)	50	35.0%	123,979	2,480	20	0	68.52	0.00	11.72	30.59	42.31	0.00	110.83
Solar Photovoltaic (Small Farm)	10	14.0%	23,732	2,373	30	0	135.36	0.00	12.49	20.37	32.86	0.00	168.22
Solar Photovoltaic (Large Farm)	25	14.0%	56,751	2,270	30	0	129.48	0.00	12.49	20.37	32.86	0.00	162.33
Pumped Storage	100	40.0%	348,721	3,487	60	0	58.39	0.00	17.66	16.12	33.78	0.00	92.17
Small Hydro	20	50.0%	95,180	4,759	50	0	65.59	0.00	0.00	14.69	14.69	0.00	80.28
Wave Power	10	25.0%	87,818	8,782	20	0	339.74	0.00	11.72	107.05	118.77	0.00	458.51
Tidal Stream Power	50	35.0%	313,027	6,261	20	0	173.00	0.00	0.00	86.02	86.02	0.00	259.02
Grand Falls Additional Power	100	34.2%	327,402	3,274	50	0	65.97	0.00	0.00	1.73	1.73	0.00	67.70
High Narrows	40	46.2%	250,000	6,250	50	0	93.22	0.00	0.00	2.11	2.11	0.00	95.34
Interconnection Purchases	350	80.0%	0	0	25	10,000	0.00	64.59	0.00	10.20	74.79	0.00	74.79
Millbank/Ste Rose	500	5.0%	98,000	196	25	12,000	33.85	301.40	0.00	0.00	301.40	0.00	335.25

Appendix 4: Stakeholder Terms of Reference

Integrated Resource Plan Stakeholder Terms of Reference

Purpose: To define the requirements for the list of stakeholders invited to the IRP consultation session.

Participant Criteria:

- Has interacted with NB Power in the past ten years on behalf of customers, industry, public sector organizations, social advocacy groups

- Has identified themselves as an intervener representing special interest groups during previous EUB hearings

- Is not an energy competitor of NB Power

- Is an official representative of a group of stakeholders rather than just one individual stakeholder:

  NB Department of Energy and Mines
  Cabinet, Government, and opposition caucuses
  First Nations (special consideration for those adjacent to Mactaquac)
  NB Power community liaison committees
  Energy and Utilities Board members and staff
  Active social media followers
  Environmental Interest groups
  Municipal and local service district councils
  Community leaders and influencers
  Academic community
  Canadian Manufacturers and Exporters
  Chambers of Commerce, Regional Economic Development units
  NB Business Council, Future NB, Atlantica Centre for Energy, ICT
  Independent Power Producers
  Canadian Wind Energy Association
  Consumers Association of Canada
  Canadian Federation of Independent Business

- Proportionate representation of the following groups:

  - Government
  - Industry
  - Residential
  - Environmental
  - Academia
  - First Nations
  - Special Interest Groups

Stakeholder Frame of Reference

Stakeholders will be asked their vision on what role NB Power plays in the environmental, economic and social aspects of New Brunswick.

Stakeholders will receive information on the purpose of the integrated resource plan, the status of projected supply compared to projected demand over the next 25 years. Tentative plans on how to meet the demand include an analysis of possible technologies, an example of how the plan serves as an input to the Mactaquac process, which is separate, and the importance of reducing and shifting demand that will delay any major construction.

Stakeholders will also receive a copy of The New Brunswick Energy Blueprint and the NB Power Strategic Plan, 2011 – 2040

How stakeholder consultation will be demonstrated in the IRP

Include comments from session in the actual report (pull quotes into the reports)

Run new sensitivities or adjust existing analysis for different supply-side and demand-side options presented by stakeholders & report back

Verify and adjust the balance between demand-side solutions and supply-side solutions, articulate any adjustments in the report

Attach consultation report to the IRP

Considerations to highlight in stakeholder materials

NB Power is subject to NB legislation (Electricity Act) that regulates its rates and mandate, this includes:

- Provide low and stable rates
- achieve a capital structure 20% equity (equivalent to $1B debt reduction)
- a reliable power system
- long-term planning in the form of an IRP (every 3 years) and 10-year financial plan (annually)
- regulatory (EUB) oversight of rates and major capital project that must take into consideration the long-term plans.

Electric utilities are also subject to business realities that include:

- reduced load growth and hence reduced revenue growth
- limited capital funds available for reinvestment
- new technologies that provide customers with alternate sources of heat and potentially electricity (disintermediation)

- aging infrastructure
- currently 100% debt-financed, which limits our ability to finance unexpected events or major capital projects
- Electric Utility infrastructure are long life assets that take anywhere between 2 to 10 years to construct
- Many renewable technologies are variable and non-dispatchable (wind, solar) and can be connected to the distribution system

NB Power is committed to be a sustainable utility including:

- 40% renewables by 2020 as in the Energy Blueprint
- Developing smart grid technologies that make the generation, delivery and use of electricity as efficient as possible and allow for the efficient integration of renewable generation
- Long-life assets are paid for over the duration of the life (plants, major Transmission lines, Distribution Facilities), drives the need for a long term plan

Transmission infrastructure takes at least two years to construct

Appendix 5: Stakeholder Invitee List

Organization	Contact	Phone	Group
Association of Professional Engineers and Geoscientists of New Brunswick	Andrew MacLoed / Brian Scott		Industry
New Brunswick Energy Institute	Annie Daigle		Association
Chief, Elsipogtog First Nation	Arren Sock		
Enterprise Greater Moncton	Ben Champoux		
Efficiency New Brunswick	Beth Pollock / Thomas MacDermott		Government
Miramichi Chamber of Commerce	Brook Hamilton, ED		Association
Greater Moncton Chamber of Commerce	Carol O'Reilly, ED		Association
Énergie Edmundston Energy	Charles Martin		Utility
Comité des 12	Claude Snow / Ronald Babin		Residential
NB Homebuilders Association	Claudia Simmonds		Residential
Perth-Andover Electric Light Commission	Dan Dionne		Utility
Association of Municipal Administrators (AMANB)	Danielle Charron		Residential
Enbridge Gas	Dave Charleson / Gilles Volpe		Utility
Instructor, Energy Fundamentals for Leaders	David Campbell		
Saint John Board of Trade	David Duplisea		Association
Union of Municiaplities of New Brunswick	David Hanson, President		Municipality
Canadian Manufacturers and Exporters	David Plante		Industry
EUB	David Young		Government
Grand-Falls Chamber of Commerce	Diane Plourde, General Manger		Association
Economic Development	Don Hammond		
Enterprise Fredericton	Doug Motty		Municipality
UNB SJ	Dr. Ken Sollows, Dept. of Engineering		Academics
UNB	Dr. Liuchen Chang		Academics
Quest Canada	Eddie Oldfield, NB Caucus Chair		Environment
New Brunswick Community College	Errol Persaud (dean of engineering)		Academics
Hampton Chamber of Commerce	Gail Kilpatrick, Admin Secretary / Peter Behr		Association
Ministry of Energy and Mines	Heather Quinn		Government
Future NB	Heather Schubert		Industry
TransAlta	Ian Gillham		Utility
Conservation Council of New Brunswick	Inka Milewski		Environment
Habitat for Humanity Fredericton	Irene Callaghan		Residential
Enterprise Saint John	Janet Scott		Municipality
	John Furey		
Acciona Energy North America	Jonathan MacDonald		Utility
Agriculture Alliance of NB	Josée Albert		Association
Conservation Council of New Brunswick	Kevin Matthews		Environment

Organization	Contact	Phone	Group
Fredericton Chamber of Commerce	Krista Ross, Ed		Association
ICT Counsel	Larry Samson		
Chief, Woodstock First Nations	Len Tomah Jr.		
Collège communautaire du Nouveau-Brunswick	Léon Landry		Academics
	Lilia Cozzarini		
	Lori Clark		
Association de francophone des municipalités du Nouveau-Brunswick	Luc Desjardins, First VP		Municipality
Edmundston Chamber of Commerce	Marc Long, ED		Association
New Brunswick Forest Products Association	Mark Arsenault		Industry
GDF Suez Energy, Caribou Wind Park	Mark Hachey		Utility
	Jason Goodhand		
Invest NB	Mark Haines-Lacey		Government
JDI	Mark Mosher		Industry
Assembly of First Nations NB	Michael Scully		
At Home Chez Soi (Mental Health Commission of Canada)	Nancy MacWilliams		Residential
Sussex & District Chamber of Commerce	Pam Kaye		Association
Flakeboard Company Ltd.	Pat Burke		Industry
Chief, Madawaska First Nations	Patricia Bernard		
Saint John Energy	Ray Robinson		Utility
Nature Trust of NB	Renata Woodward / Margo Sheppard		Environment
Canadian Federation of Independent Business	Richard Dunn		Industry
Invest NB	Robert Macleod		Government
Conseil économique	Robert Moreau / Anne Hebert		Association
Chief, Woodstock First Nations	Rod Lyons, CFO		
Association de francophone des municipalités du Nouveau-Brunswick	Roger Doiron, Chair		Municipality
Renewables NB	Roland Chiasson		Embedded Generation
NB Lung Association (Community Outreach)	Roshini Kassie		Environment
IBEW	Ross Galbraith / Greg Wright		Residential
Irving Oil Limited	Sean Boyle		Industry
Peace NB	Sharon Murphy		
Community Living	Sherri Shannon		Residential
Enterprise Saint John	Stephen Carson		Municipality
	Stephen Russell		
PotashCorp	Stewart Brown		Industry
Parnters for Youth Fredericton	Sue King		Residential
NB Business Council	Susan Holt		Industry

Organization	Contact	Phone	Group
Twin Rivers Paper Company	Tim Lowe, CEO		Industry
UNB - Social scientist	Tom Beckley		Academics
McCain	Tom Green / Guy P Gaudet		Industry
The Gaia Project	Vanessa Paesani /		Environment
The Gaia Project	Jimmy Therrien		
Bathurst Chambers of Commerce	Vilma Glidden, ED		Association
U de M	Yves Gagnon		Academics
Campbellton Chamber of Commerce			Association
ACOA			
Renewables NB	Greg Lynch		
Renewables NB	Tim Amberly		
Sustainable Energy	Sam Arnold		
Sustainable Energy	Keith Helmuth		
PotashCorp	Yevgen Yevsyeyev		
Thoughtfull Dwellings	Garth Hood		
	Brenda Firlotte		
	Darwin Curtis		
	Chief Candice Paul / Shyla O'Donnell		
	dr Keith Wilson		
NB Utilities	John Lawton		
	Louise Comeau		
Atlantic Salmon Federation	Bill Taylor		
Atlantic Salmon Federation	Elizabeth Ames		
Atlantic Salmon Conservation Foundation	Steve Chase		
Friends of Mactaquac Lake	Larry Jewett		
WWF Canada	Simon Mitchell		
Union of Municiaplities of New Brunswick	Bethany Thorne-Dykstra		
Union of Municiaplities of New Brunswick	Raymond Murphy		
Union of Municiaplities of New Brunswick	Mayor Theresa (Terry) James		
Union of Municiaplities of New Brunswick	Mayor Arthur Slipp		
	Chief Wendy Wetteland		
	Sacha Boies Novak		
Mount Allison University	Brad Walters		
Economic and Social Inclusion Corporation	Leo Paul Pinet		
Economic and Social Inclusion Corporation	Stephane LeClair		
	Jim Emberger		
	Mike MacDonald		
	Chris Rouse		
UNB	Daniel McHardie		
City of Fredericton	Duncan Lombard		
NB Power	Frank Britten		
Universite de Moncton	Dominique Babineau		

Appendix 6: Stakeholder Invitation Text

Dear <name>,

You are cordially invited to attend a stakeholder workshop intended to provide NB Power with meaningful input on the development of our long-term electricity supply plan for the Province of New Brunswick.

The Integrated Resource Plan (IRP) is a strategic planning document that will identify how NB Power can meet projected customer demand for electricity during the next 25 years, while respecting our mandate to provide reliable, accessible service at low and stable rates. While the plan is forecast for 25 years, NB Power updates it every three years to ensure we can capture new technology, changes in customer demand and accurate fuel pricing.

The new Electricity Act requires that NB Power submit the IRP to the Energy and Utilities Board in 2014 with input from our stakeholders. This facilitated workshop will assist in that process.

Attached is a document providing you with an overview of the IRP which identifies the current state of our electricity system, outlines the projected electricity demand and electricity supply from our generating stations, and provides a high-level strategy on how we might meet the supply gap.

To assist in the creation of a focused and productive workshop, we ask you to reflect in advance on the following statement and three questions, which will form the basis of our discussions.

NB Power is inviting input from stakeholders on its 25-year Integrated Resource Plan to satisfy future energy demands for residential, commercial and industrial customers in New Brunswick. This Integrated Resource Plan is meant to be an evolving document, updated every three years, to reflect changing demands and technology, and will be filed with the Energy and Utilities Board for public consideration in the spring of 2014.

Given that:

> *NB Power must operate within boundaries of its legislative and regulatory mandates to provide reliable electricity with best-cost solutions that achieve low and predictable rates in a way that sustains the social and natural environment,*
>
> *The Energy Blueprint has committed NB Power to incorporate 40 per cent renewable energy into the grid by 2020,*

1) *How can NB Power help contribute to a successful New Brunswick?*

2) *How can NB Power help contribute to a clean environment for future generations?*

3) *What role could NB Power play in ensuring the development of new opportunities for energy innovation in New Brunswick?*

Thank you in advance for considering this workshop. Your past contributions to NB Power have helped us set our direction and improve how we serve customers. We value the partnership we have developed with you and look forward to speaking with you face to face about the challenges and opportunities that lie ahead.

Details of the event are as follows:

Date:

Time:

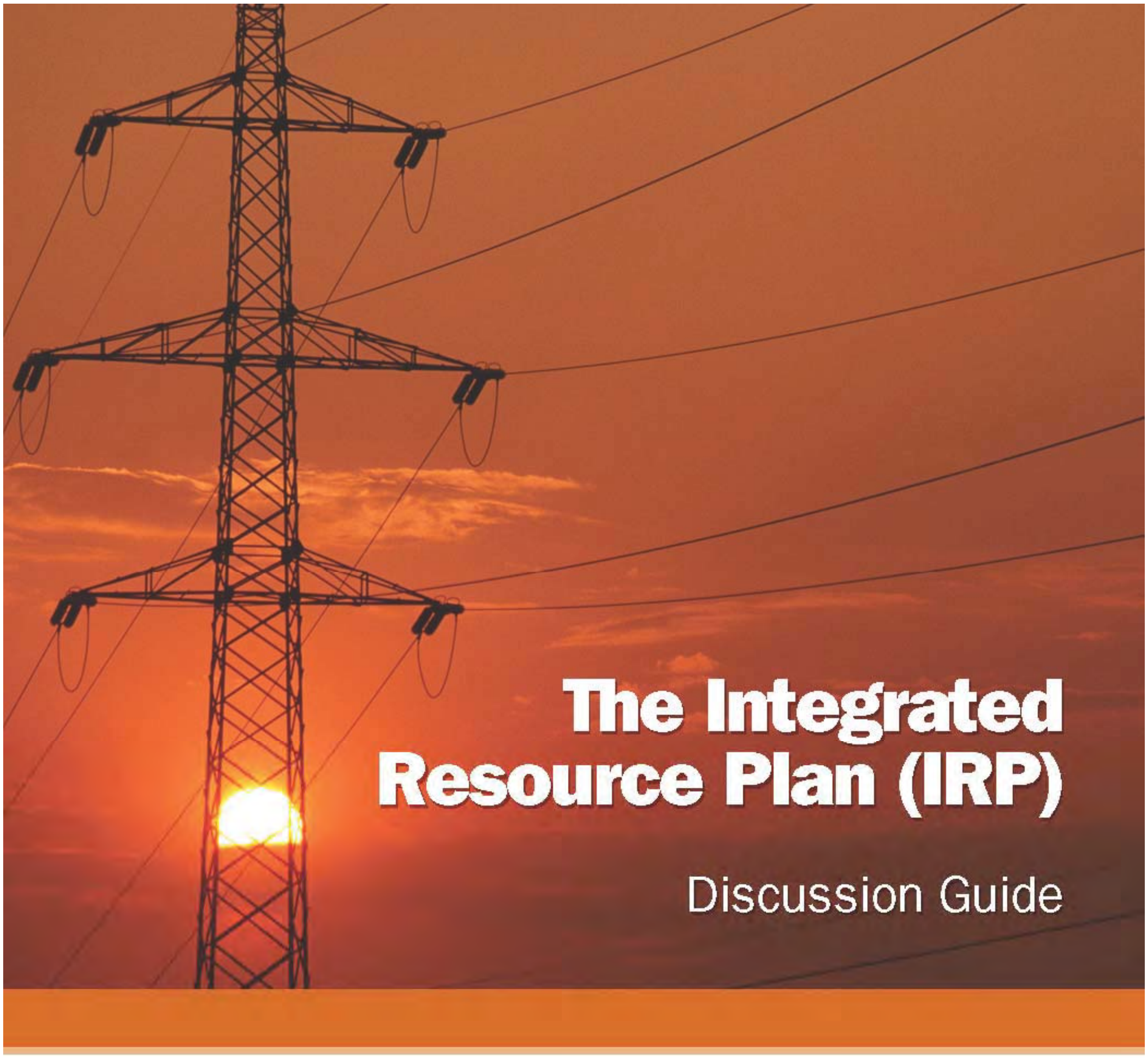
Place:

Please RSVP to <e-mail> by <Date>. Once your attendance is confirmed, we will follow up with more information including a full agenda. If you have any questions in the meantime, please contact <name>. We look forward to hearing from you.

Regards,

Gaëtan Thomas

Appendix 7: Stakeholder Discussion Guide



Énergie NB Power

Introduction

The Integrated Resource Plan (IRP) is NB Power's planning tool to meet the changing demand for electricity in New Brunswick over a 25 year period. It assesses the most cost-effective, reliable and environmentally sustainable electricity options possible. This discussion guide introduces you, our customer, to the process for developing the IRP, an analysis of the future demand required and the state of our power supply going forward, and the vital role of Smart Grid in NB Power's future.

Your feedback is a key consideration that will shape the IRP and, therefore, the future of NB Power. It is important for us to get guidance from you, our customers, on what role you see NB Power playing as your electricity provider.

The IRP represents New Brunswick's future energy requirements based on population, customer expectations, energy needs for households and businesses, and promoting economic growth in New Brunswick.

Did you know?

A Smart Grid is a modernized electrical grid that uses technology to improve the efficiency, reliability, economics, and sustainability of the production and distribution of electricity by using two-way communication technology between the source of the electricity and the consumer.

About the Integrated Resource Plan

The integrated resource plan is NB Power's long-term plan that seeks to answers the following questions:

1) What is our current supply of electricity and what is the cost of delivering it using existing technology?

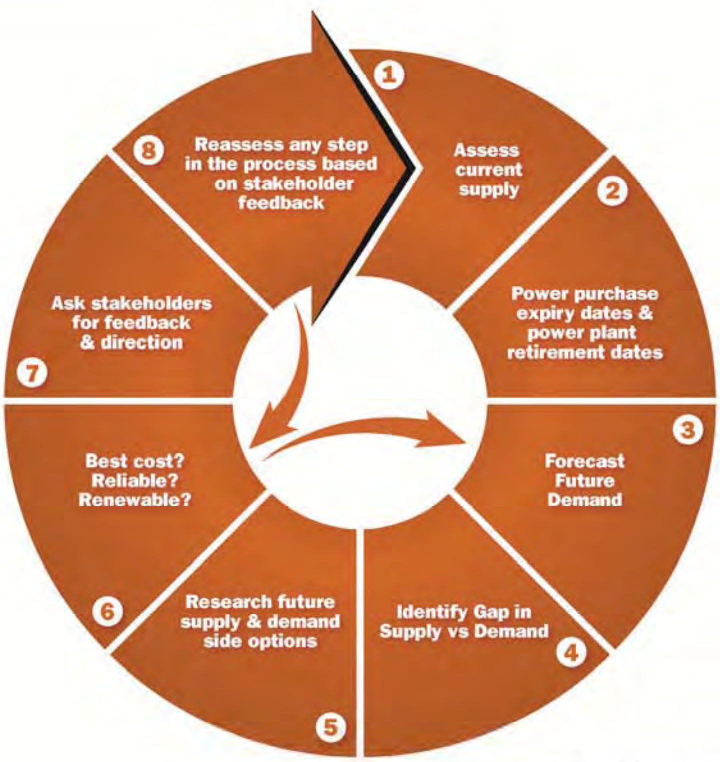
2) What impact does our current electricity supply have on the environment?

3) How do we ensure a reliable supply of power now and going forward?

4) How will changes in society and industry impact New Brunswick's future need for electricity?

5) What new technologies and techniques can NB Power use to provide the most cost-effective, reliable and sustainable?

NB Power follows a well-defined process that is standard across utilities to create the integrated resource plan. In a simplified fashion, the following diagram depicts the key elements of a step-by-step process that captures long term changes in the supply and demand of energy.



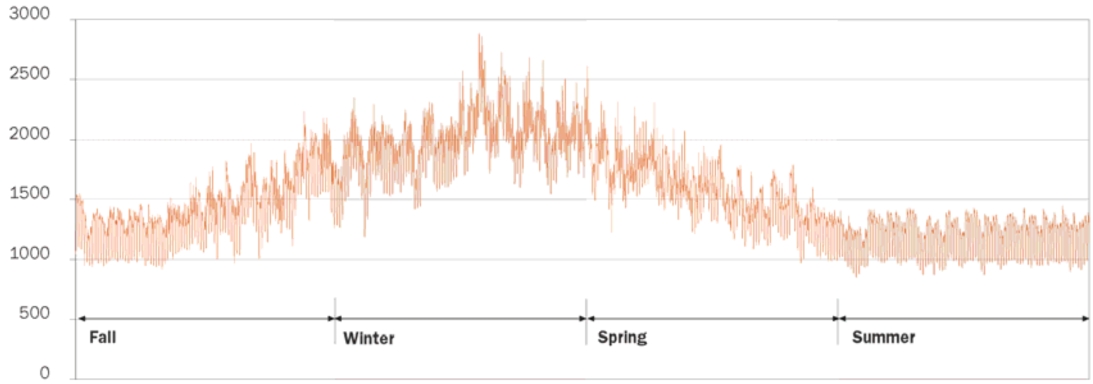
About NB Power

Electricity is integrated into our everyday lives; from the pump that provides us water to brush our teeth in the morning to the lights we shut off before going to bed. What feels like a simple flip of a switch translates into a complex system of 13 generating stations sending electricity across 26 000 km of power lines, managed by 2 300 employees on a 24/7 basis.

NB Power uses diverse sources of generation, including our seven hydro dams, our three thermal stations, our nuclear power plant, and purchased power from third party generators, to ensure reliability and to take advantage of changing market costs. NB Power must maintain a level of generating capacity to meet the peak demand of customers, typically on winter mornings when families are getting ready for the day, when we use more electric heat and lighting. Compared to other provinces, New Brunswick uses a higher amount of electric heat, which makes up approximately 60 per cent of New Brunswickers' annual consumption. The peak required to serve our customers on cold winter days is 3200 Megawatts (MW), but we can use as little as 1000 MW on summer days. The chart below shows our average hourly use of electricity over a one-year period. On Jan. 24, 2013, when it was -32°C with the wind chill, we required 3117 MW of electricity between 7 a.m. and 8 a.m

To transport electricity across New Brunswick, NB Power has more than 6 700 km of transmission lines that carry high voltage electricity across the province and beyond to homes, large industrial customers, and export markets. Our transmission system has connections to our neighbors in Quebec, New England, and Nova Scotia that allow us to buy and sell electricity, helping us meet peak demand and ensuring a reliable source of electricity.

Actual Load 2010-2011 (MW)



Did you know?

New England's peak for electricity demand is in the summer due to the increased use of air conditioners. Because New England and New Brunswick have opposite peak times (ours is in the winter), both areas benefit from transmission interconnection betweenthe two areas.

System Map

NB Power's Evolving, Smart Grid

As New Brunswick's electricity needs have changed, particularly with changes in industry, so has NB Power's grid. We have built more transmission lines to Quebec and the United States to strengthen the gird and benefit from purchasing electricity, which at times costs less money and takes less time than building a power plant.

NB Power puts a great deal of research and planning when considering a change to our grid. Our project teams consider environmental factors, costs of construction or decommissioning and system reliability when making any major decision. The planning is especially important as it takes, on average, five to 10 years to plan and build a new source of generation and an average of two years to plan and build a transmission line.

New technology provides us with efficient power plants, and changes our assumptions of the source of power. Across New Brunswick, residential customers, communities and industries can generate smaller amounts of electricity using renewables to serve the immediate area, often referred to as distributed generation. A good example of this phenomenon is the Fredericton Solid Waste Commission's Landfill Gas Utilization Plant (LGUP) that uses naturally-occurring methane from the landfill to generate up to two MW of electricity.

As well as the distributed forms of energy generated, New Brunswickers can change the way they use electricity to reduce consumption and shift when we use it, thus reducing the peak that we have to meet. By reducing and shifting energy demand, we can lessen the need to build or buy as much electricity to meet the peak in the winter. NB Power has entered into a ten-year program with Siemens Canada to build Smart Grid, a series of new technology solutions that will help us reduce and shift demand for electricity, and allow customers more control over the amount of energy they use. Smart Grid will enable two-way communication between the generators and the locations that consume electricity. By doing so, our electricity use will follow supply, rather than variations in use. For example, home owners will have information to either reduce the amount of electricity use in their home by remotely managing the heat, or they could install water heaters and replace baseboard heat with thermal storage that heats up bricks during non-peak times and provides hot water or heated air when required.

By centrally managing a group of distributed generating facilities and using the technology to shift the demand for electricity to a later time, NB Power can create a virtual power plant that will supply electricity to a region without building a physical plant.

Direction from the Provincial Government on NB Power's Future

NB Power is regulated by the Energy and Utilities Board (EUB) and directed by *The Electricity Act* to operate under the following policy objectives:

- To provide low and stable rates
- To supply a reliable power system
- To have 40 per cent of our electricity supply provided by renewable energy by 2020

After October of 2014, NB Power must submit an application before the EUB for a rate change. The EUB will refer to the IRP as an input into their decision-making process when considering a rate application. Going forward, the EUB will also refer to the IRP when considering any capital project above $50 million.

New Brunswick's Projected Demand and Supply

During the next 25 years, NB Power is projecting an increase in demand in electricity of approximately 1% each year, based on population growth and industry trends. Over that same 25 years, power purchase agreements with non-utility generators, which make up approximately 525 MW of the electricity we use, will expire. Three of our power plants, Grand Manan, Millbank and Ste. Rose, are scheduled for retirement over the same 25-year period.

If New Brunswick maintains the projected level of demand, NB Power will have to construct or enter into a new power purchase agreement as early as 2027. Although that seems like many years away, in utility terms, it is a short time. By 2031, NB Power could have a supply gap of approximately 800 MW, which is close to the equivalent of Belledune and Mactaquac stations combined.

If we achieve our goal of reducing consumption by 635 MW through our partnership with Siemens and other efficiency programs, our winter peak will be reduced and we won't require as much generation capacity in New Brunswick. If this effort is successful, we could avoid or delay the need to refurbish or build a new power plant, potentially saving New Brunswickers hundreds of millions of dollars.

Continued on page 4

Did you know?

NB Power has not only enough electricity to meet the peak demand (i.e. the amount used on cold days when everyone is getting up or getting home from work) available and also maintains a reserve amount of electricity, in case there is a disruption of power generation. NB Power achieves this through a combination of in province generation and reserve sharing agreements enabled by our transmission links to other utilities.

New Brunswick's Projected Demand and Supply *(continued)*

Options Considered

As NB Power makes excellent progress on shaving off the peak and reducing electricity consumption, we are researching options to fill the gap in electricity supply for the 2030s and onward. The reduction of electricity demand will decrease the gap in electricity supply for the next 20 years.

The three options for to meet NB Power's supply gap are to Buy, Build, and Re-Source. The IRP will develop high level recommendations for each, setting a direction to measure risk, environmental impacts and financial benefits.

Buy – NB Power has the option of entering into power purchase agreements from generators within or outside of New Brunswick. Our transmission system has the capability of importing approximately 2000 MW of electricity. With renewable electricity available to us from Hydro Quebec and, potentially, from the Muskrat Falls project, NB Power can purchase electricity with minimal impact to the environment. However, NB Power must still be able to generate some of the required electricity used in the province to ensure a reliable, secure source of electricity.

Build – In the next 25 years, NB Power has the option to build on to our diverse fleet of generating stations. There are two options when it comes to building generation. One is to build in a new location, known as "a green field build." The other is to build on an existing location, which allows us to use water cooling systems and transmission and distribution structures already in place.

Did you know?

NB Power's diversity of fuel sources means that we can rely on lower-priced generation if there is a sudden increase in any one fuel price, similar to what the industry faced in the late 1970s when oil prices increased significantly.

Re-Source – The basic structure for any generating plant is a spinning turbine that generates electricity. The turbine spins from water, steam or from direct jet propulsion, regardless of the fuel source.

With new technologies, NB Power can look into more efficient, cost effective sources of fuel that emit fewer greenhouse gases (GHG) for our existing plants. For example, Coleson Cove, which only runs to meet peak demand due to the high cost of its oil fuel and the higher GHG emissions, could be converted to natural gas.

As technologies and circumstances change, so will the recommendations presented in the IRP. However, the IRP helps set the vision of where NB Power is going.

Given these three options and the need for electricity in New Brunswick going forward, here is what we are asking you, as customers, to consider:

Given that:

NB Power must operate within boundaries of its legislative and regulatory mandates to provide safe, reliable electricity with best cost solutions that achieve low and predictable rates in a way that sustains the social and natural environment,

The Energy Blueprint has committed NB Power to incorporate 40 per cent renewable energy into the grid by 2020,

1) How can NB Power help contribute to a successful New Brunswick?
2) How can NB Power help contribute to a sustainable environment for future generations?
3) What role could NB Power's long term plans play in ensuring the development of new opportunities for energy innovation in New Brunswick?

Once more we would like to thank you for considering taking part in this initiative. Your feedback will inform our thinking and influence our decisions as we plan New Brunswick's energy future together.

Appendix 8: Stakeholder News Release

News Release

NB Power considers options for long-term energy supply plan

January 30, 2014

Fredericton, N.B. – NB Power is seeking input into the development of a long-term electricity supply plan for the Province of New Brunswick beginning with a workshop in Fredericton on January 31.

Individuals representing the spectrum of NB Power's customer base have been invited to attend the workshop, including residential, small business and industrial, non-profit sectors and municipalities.

"We are excited to hear from our customers about how we can plan for the future," said Gaëtan Thomas, President and CEO of NB Power. "We value the partnership we have developed with our customers and look forward to this, the first of many opportunities to speak with them face to face about the challenges and opportunities that lie ahead."

Information gathered at the workshop will help inform NB Power's Integrated Resource Plan (IRP), a strategic planning document that will identify how the utility can meet projected customer demand for electricity during the next 25 years and achieve a minimum of 40 percent from renewable sources of energy, while respecting its mandate to provide reliable, accessible service at low and stable rates. The IRP process is a long-term planning tool that is standard across utilities. While the IRP is forecast for 25 years, NB Power updates the plan on a regular basis to reflect new technology, changes in customer demand and accurate fuel pricing.

The new Electricity Act requires NB Power to submit an IRP to the Energy and Utilities Board (EUB) at least once every three years. The EUB will consider the IRP, along with the ten-year strategic, financial and capital investment plan and other considerations in approving or fixing rates. Each iteration of the IRP will involve input from the utility's customers.

MEDIA CONTACT: Deborah Nobes, Communications, (506) 458-4838 or email: dnobes@nbpower.com.

Appendix 9: Stakeholder Sign-In Sheet

Énergie NB Power

Date: January 31, 2014 / le 31 janvier, 2014 **Location / Endroit: Crown Plaza, Fredericton, NB / N.- B.**

Integrated Resource Plan Workshop Sign-In Sheet

Fiche d'inscription pour l'atelier du Plan de ressources intégrées

Name / Nom	Telephone Number / Numéro de téléphone	E-mail Address / Courriel	Organization / Oraganisation
PETER BEHR			HAMPTON CHAMBRE CORP. COMMERCE
Anne Hebert			Conseil économique du NB
Raymond Murphy			UMNB
Simon J. Mitchell			WWF.
John Lawston			EqB
Margo Sheppard			Nature Trust of NB.
Errol Persaud			NBCC
DAVID PLANTE			CAE
MARK HACHEY			Caribou Wind

Name / Nom	Telephone Number / Numéro de téléphone	E-mail Address / Courriel	Organization / Oraganisation
Tom MacDermott			Efficiency NB
Jason Goodhand			
Ken Sollows			ONB SJ / Self
Ronald Babin		.ca	
Mark Mosher		driving.com	JDI
Krista Ross		hamber.ca	F'ton Chamber
Vanessa Paesani		ject.ca	The Gaia Project
Roland Chiasson			Renewables NB.
Barb MacKinnon		g.ca	NB LUNG
Roshini Kassie			NB Lung Assoc.
Sam Arnold			Sust. Engy Group
Keith Helmuth		om	Sustainable Energy Group

Name / Nom	Telephone Number / Numéro de téléphone	E-mail Address / Courriel	Organization / Oraganisation
CHARLES MARTIN		.ca	LEDSTONE ENERGY
Tim Ambery			Falls Brook Centre
Susan Holt			NBBC
Wendy Wetteland			NBAPC.
Edward [illegible]			NBP.
RAY ROBINSON			S J ENERGY
Sharon Murphy			PEACE-NB
[illegible]			CBC
Frank Johnston			Greenlight / CCNB

Énergie NB Power

Date: January 31, 2014 / le 31 janvier, 2014

Location / Endroit: Crown Plaza, Fredericton, NB / N.- B.

Integrated Resource Plan Workshop Sign-In Sheet

Fiche d'inscription pour l'atelier du Plan de ressources intégrées

Name / Nom	Telephone Number / Numéro de téléphone	E-mail Address / Courriel	Organization / Oraganisation
Susan King			Partners for Youth
Chris Rouse			~~News~~ New Clear Free Solutions
Louise Maclaren McCann			Maclaren McCann
Gilles Volpe			Enbridge
Greg Lynch			Falls Brook Centre
Sacha Boies Novak			New Brunswick Ath. Ppl. Council
Brody Hanson			Siemens

Énergie NB Power

Date: January 31, 2014 / le 31 janvier, 2014 **Location / Endroit: Crown Plaza, Fredericton, NB / N.- B.**

Integrated Resource Plan Workshop Sign-In Sheet

Fiche d'inscription pour l'atelier du Plan de ressources intégrées

Name / Nom	Telephone Number / Numéro de téléphone	E-mail Address / Courriel	Organization / Oraganisation
Darwin Curtis			Climate Change Secretariat
Annie Daigle			NBEI gyinstitute.ca
Brian Scott			APEGNB.
Art Shipp			Town of Woodstock
Jimmy Therrien			The Gaia Project
Kevin Matthews			
D. McHardie			UNB
Shyla O'Donnell			St. Mary's First Nation
Greg Wright			IBEW37

Name / Nom	Telephone Number / Numéro de téléphone	E-mail Address / Courriel	Organization / Oraganisation
Heather Quinn			Dept. Energy & Mines.
Garth (Ty)			Thoughtful Dwellings
Léon Landry			CCNB
Eddie Oldfield			QUEST
SEAN BOYLE			IRVING OIL

Integrated Resource Plan Workshop /L'atelier du Plan de ressources intégrées

Jan. 31, 2014 / le 31 janvier 2014

Appendix 10: Stakeholder Exit Survey

At the close of the stakeholder session, participants were invited to complete an exit questionnaire focused on identifying the quality and quantity of information provided and providing opportunity to suggest improvements. Of the 51 participants, 24 completed questionnaires and their results are summarized below.

1. Prior to today how knowledgeable would you say you were about NB Power's grid?

   Very knowledgeable = 5 Knowledgeable = 11 Somewhat knowledgeable = 7 Not knowledgeable at all = 1

2. Following the workshop, how knowledgeable would you say you are about NB Power's grid?

   Very knowledgeable = 9 Knowledgeable = 9 Somewhat knowledgeable = 6 Not knowledgeable at all = 0

3. In terms of the content of the information you received today, would you say that the information was:

   Too technical = 0 Not technical enough = 6 Just right = 17 (OTHER) biased = 1

4. A) Were all of the areas that are of interest to you about the Integrated Resource Plan?

   Yes = 12 No = 11 Did not answer = 1

   B) If not, what areas would you like to see included?

   - "I would have liked to see the progress/work done by NB Power on the previous steps of the IRP"
   - "Innovation"
   - "Efficiency, Efficiency NB"
   - "Education as part of a contributive piece to the solution (including colleges and universities)"
   - "More detail on smart grid, capacity replacement"
   - "Community based sustainable power. Progressive taxation channeled to promote green community power"
   - "System protection from geomagnetic pulse events (solar flares)"
   - "Integration of plan with NB Climate change plan"
   - "Further explanation of the role of Efficiency and Conservation"
   - "More on process & actual content of IRP"
   - "No information on where we are with the 40% & the breakdown of that"
   - "Include costs of secondary environmental impacts"
   - "No discussion of future energy efficiency programs other than smart grid"

5. How often have you visited the NB Power website?

   Never = 2 Never before today = 1 Occasionally = 15 On a regular basis = 6

6. What area of interest do you represent?

   Environment = 13 Municipality = 4 Academia = 5 Government = 2 Industry = 4 Other = 12
   (Citizen & power user, NGO health, community (civil society), NGO, education (3), community based renewable energy generation, non-profit organization, labour, small business, health charity (New Brunswick Lung Association)

7. Were all of your questions answered to your satisfaction?

   Yes = 17 No = 3 Did not answer = 4

Appendix 11: NB Power Response to Stakeholder Input

Stakeholder suggestions (number indicates votes by participant):	**NB Power response:**
Efficiency and Conservation 1. “Promote energy conservation” 2 2. “Continue developing the smart grid, lower energy consumption using energy efficient home heating devices and on demand water heaters.” 2 3. “Make better use of Green Municipal Funds (FCM) for retrofits etc through NB Municipalities” 4. “Move to a new housing standard that uses 80-90 per cent less energy can also stimulate a high quality building component business opportunity at the same time healthy, more comfortable and durable houses are constructed with more local labour. Energy savings pay for hidden construction costs.” 5. “Reduce in-province demand through efficiency and shifting to allow for more exports.” 6. “Encourage conservation and efficiency in all buildings and homes” 7. “Integrate provincial and federal energy savings programs” 8. “Aid all consumers in reducing electricity costs.” 9. “Assist New Brunswick industrial clients with peak demand reduction.” 10. Create “additional retrofit programs” 11. “Reduce the base load through efficiency and conservation programs, thereby increasing the percentage of renewables.” 12. “Help users shift demand, reducing cost.” 13. “In many jurisdictions, targeted higher energy rates combined with stringent efficiency and progressive renewable energy programs have led to lower energy bills as well as sustainability and resilience.” 14. “Encourage end users to use the least cost, most efficient energy sources (may not electricity)” 15. NB Power should have efficiency and conservation as guiding principles and a component of rate structures including peak rates for all consumers.” 16. “Work with efficiency NB to provide more incentives for home owners who want to install green technologies and improve their building envelope.” 17. “Discourage installation of electric baseboard heating, and encourage development of multi-fuel central heating systems.” 18. “Support alternative solutions to baseboard electric heating.” 19. “Provide energy in a way that is respectful of people and nature.” 20. “Help educate government on what sustainability is and collaborating with all departments to mandate sustainability in policy development”	 The IRP contains 600 MW and 2,000,000 MWh of peak demand and energy reductions resulting from efficiency and demand side management programs. These reductions will provide significant benefits to New Brunswickers over the coming decades, reducing the total cost to supply our energy needs by over $1 billion. (Ref: s.9.2.2) Through a combination of energy efficiency programs and RASD initiatives NB Power will help customers reduce consumption, reduce and shift demand on the system, and implement incentives (rates, rebates, etc.) to make the electricity grid as efficient as possible. (Ref: Chapter 6 and Appendix 12 - smart grid/RASD)

Stakeholder suggestions (number indicates votes by participant):	NB Power response:
Target setting and measurements	
21. “Ensure RASD targets are met, verified and permanent.” 2 22. Consider “efficiency and conservation as part of the equation” along with supply, load and cost when setting targets and planning IRP 13 23. “Set and achieve more ambitious goals for renewable energy focused on distributed generation” 24. “Report on/include rigorous environmental metrics. Ensure we are not operating in a silo. Work closely with DELG on Climate Change Action Plan” 1 25. Measure “environment and greenhouse gas reductions” 2 26. “make the distinction between green energy, low carbon and renewables and define how each contributes to a sustainable environment, or not” 27. “Set realistic environmental objectives and use the latest technology to achieve them” 28. “Include secondary environmental effects in financial analysis.” 1 29. “Implement full cost and full benefit accounting system” 6 30. “Use maps of current and forecasted scenarios including demand and supply for business as usual and high efficiency scenarios to inform IRP.” 1 31. “Bien que souvent difficile a établir avec haute precision, toujours inclure dans l’équation tous les estimés de coûts environnementaus associés à chaques étape de production et distribution ainsi que les impacts collatéraux occasionnés sur environnement solutions sont exhaustivement les meilleurs.” 32. “Listen and observe around the world to pull in what other countries are doing right”	Evaluation is a key component of all demand side management plans. The 3-year energy efficiency plan contains the start of an evaluation plan that will evolve over time. Ref: s.6.2 Energy efficiency and RASD spending will be included with all other NB Power spending when scrutinized annually by the Energy and Utilities Board. Ref: s.1.1

Stakeholder suggestions (number indicates votes by participant):	NB Power response:
Renewable Energy Sources **33.** “Work with Hydro Quebec to utilize their 40,000 MW of flexible hydro power to be able to provide the maximum amount of non-hydro renewables for the east coast of North America” 3 34. “Prioritize Hydro Quebec purchased power over New England fossil fuel power to help achieve 40 per cent renewable portfolio” 1 35. “Maximize renewable energy generation” 1 36. “Adopt a program similar to the Halifax solar city program 1 37. “Build more wind farms!” 1 38. “Encourage end users to use cleaner energy sources (may not be electricity as currently generated)” 39. “Create a client demand for power from the renewable sector ie: wind/solar/tidal/algae for biodiesel (not really for electricity but nonetheless can provide a new renewable energy source). Demand will lead to new industries in NB.” 40. “Allow renewable energy aggregators (eg solar) to sell on spot market and guarantee purchase of new renewables.” 41. “Invest in renewable energy courses that balance needs” 42. “Look at all options for renewable and sustainable energy”	Renewable energy is a key part of NB Power's supply options going forward. Ref: s.4.2 and 8.3 The Renewable portfolio standard sets the minimum requirements for renewables in the near to mid-term Ref: s.1.1 However, as technologies mature, the economics for customers to connect local distributed renewable generation will improve. RASD and Smart Grid initiatives are will be designed to meet those challenges by allowing more renewable to be connected to the system than is possible today. Ref: Appendix 12 - smart grid/RASD

Stakeholder suggestions (number indicates votes by participant):	NB Power response:
Climate change 43. “Have a more ambitious target for renewables/non-emitting generation and phasing out Belledune (coal) and Coleson Cove (Oil)” 1 44. “Fostering energy efficiencies, conservation and renewables (wind, solar, biomass, geothermal) Phase out of nuclear energy (costly and dangerous)” 1 45. “Maximize additions of non-intermittent generation from zero or lower emission sources and RASD initiatives” 1 46. “Research and develop sources that don’t produce high amounts of air pollutants or GHGs. Must balance health, environment and power needs. Limit fossil fuel and biomass fuel use.” 1 47. “When reducing GHGs do not choose solutions that increase air pollution, ie: wood burning. Reduce subsidies on fossil fuels (this may be a federal issue).” 1 48. “(avoid) having efforts toward GHG emission reductions and those of Atlantic Canada WIPED OUT by its colleagues at DEM promoting highly emitting shale gas and bitumen pipeline” 1 49. For a “sustainable future, move to a low or no carbon power generation (this will also drive innovation)” 50. Be a “leader in mitigating climate change impacts.” 51. “Invest in local projects that result in lower CO2” 52. “Work with communities to provide innovative electric solutions for public transport” 1 53. “Take on greater responsibility for transitioning the transportation sector from one dependent on fossil fuels to zero-emitting technologies 9eg: EV program)”	 NB Power supports the provinces climate action plan and is committed to meeting all GHG regulations. This IRP will result in significant GHG reduction through the energy efficiency and demand side measures identified in the IRP. These measures will delay supply side options, many of which are carbon emitters. Ref: s. 3.5,8.2 and 8.3

Stakeholder suggestions (number indicates votes by participant):	NB Power response:
Community-based energy development	
54. Seek “community energy solutions” 7 55. “Smart grid, two-way metering, net metering with no resets” 3 56. “Empower communities to sustainably produce power with local resources.” 2 57. “Incorporate community-based energy generation in system planning” 2 58. “Community partnerships including feed in tariffs, net metering, renewable energy rentals” 1 59. Support “energy development that promotes community engagement.” 60. “Take consideration all social and economic households in planning the IRP.” 61. “Invest a percentage into local environmental initiatives.” 62. “Facilitate community-based generation” 63. “Partenariat avec communauté surtout les projets de generation.” 64. “Promote and prioritize small green projects in regions vs mega projects that require additional transmission.” 65. “Invest in local projects that result in CO2 from and or back and credit offsets. Augment resiliency of grid and communities and critical infrastructure with renewable sources, not diesel. Support local NGOs, schools, municipal associations to improve energy literacy” 1	Community Energy is required for the plan to achieve the new RPS target of 40% by 2020. The plan contains 75 MW and 300 GWh of capacity and energy that is anticipated to fall under a community/locally owned requirement within the new RPS regulations. Ref: s. 8.3
Post-Secondary Education and Research Cooperation	
66. “Make a long-term commitment to support applied research in energy at the colleges and universities in NB and collaborate with the NB Energy Institute” 3 67. “Support NB universities doing R and D to fun energy innovation research projects” 68. “Invest in universities and colleges toward research and development. Invest in in-house R and D” 69. “Travail avec college et univ. supporter formation et accroitre R and D” 5 70. “NB Power should provide research and develop support for alternative energy and efficiency innovators in New Brunswick.” 71. “Travailler avec le ministéere de l’éducation et les colleges au développement de programmes specializes sur les technologies de l’énergie pour stimuler la créativité des futures generations de travailleurs et l’innovation vers des solutions nouvelles et rafraichissantes.” 72. “Dans tous les programmes pertinents, collaborer de prés avec les universities francophones et Anglophones afin d’assurer plus de formation rigoureuse et continue dans le domaine des technologies ennovante de l’énergie, plus particulierement l’énergie renouveable.”	Education and energy literacy are requirements for the success of energy efficiency and all RASD programs. The 3-year efficiency plan has resources targeted to education and customer awareness, and RASD programs will contain customer and stakeholder engagement components. Ref: 6.2, Appendix 12 - smart grid/RASD NB Power will partner with schools, colleges and universities to ensure that young people understand energy issues and that the workforce is prepared to participate in the future of energy development

Stakeholder suggestions (number indicates votes by participant):	NB Power response:
Public Engagement 73. “Low income new Brunswickers must not suffer as we transition to a no carbon economy. NB Power must engage in programs to help low-income consumers.” 74. “increase energy literacy” 4 75. “educate and engage the public” 3 76. “Place a high value on public input” 1 77. “Engage aboriginal people on and off reserve” 1 78. “Help customers understand where their electricity comes from and how they use it to help them use less. Don’t be afraid to invest in and develop new, not-so-common renewable source technologies now (NB should be a leader in trying out new technologies. Good for our education system/students, jobs, economy).” 1 79. Include “sustainability graph on power bill (like power consumption graph” 1 80. “social community engagement and participation” 1 81. “Open transparent sharing of their plans including long-term estimate rate increases will allow businesses and industries to improve their own long-term planning, leading to improved competitiveness and increased innovation!” 82. “Educate students and general public on how to engage personally and as a community in the sustainability process” 1 83. “NB Power can do more of what you are doing today – consulting with the public.” 84. “S’Assurands d’appuyer initiative alimenter les connais.” 85. Ensure “students are aware of the situation” 86. “Promote energy self-reliance” 87. “I would like to see NB Power ensure that my generation is educated on how our daily habits contribute to the increase in electricity consumption” (from a university student) 88. “Continued involvement of different groups in looking at planning for energy innovation through financial incentives.”	 The vision of a sustainable utility requires that the IRP address not only economic and environmental issues, but social issues as well. NB Power has initiatives in place to increase public engagement and consultation, First Nations partnerships and social responsibility. Ref: s.3.5.2

Stakeholder suggestions (number indicates votes by participant):	NB Power response:
Innovation and Business Development 89. “NB Power could be a service provider of energy products. Think of Rogers/Bell cellphone market. It could be similar with marketing and service of heat pumps/electric cars” 2 90. “Allow for more small-scale projects and develop new technology and create jobs.” 91. “Recognize that every million dollars invested in renewable energy/energy efficiency creates 7X more jobs than the same amount invested in oil and gas” 1 92. “Unlock options by getting out of costly nuclear energy. Free up resources by better things overall in real innovation” 1 93. “Contribute to the NB Innovation Foundation in sponsoring an energy focused component to their activities.” 1 94. “Contribute to economic development by helping New Brunswickers become active prosumers and energy planners.” 95. “Open the market to sustainably produced community power and paying them for it as well as using a carbon tax for large emitters to subsidize community energy innovation.” 96. “Pilot projects to evaluate newest alternative technology” 97. “make necessary changes to the electricity act to allow for innovation” 98. “Use maps to inform community energy plans” 99. “Support local innovators (businesses and schools) to prototype solutions. Encourage the use of interoperable standards (eg. OGC)” 100. “Become a pilot province, a living lab for small and medium-sized enterprises who leverage energy” 1 101. “Maximize locally developed and deployed innovations through partnership with industry, universities, entrepreneurs and investors in an accelerator or incubator community.” 102. “Traiter l’énergie comme un levier de développement économique. Pour chaque pourcentage d’approvisionnement qui doit venir d’énergie renouvelable s’engager à choisir des options qui auront des retomblés économiques pour les regions et communautés du NB et travailler avec les entreprises et intervenants des communautés du NB pour y arriver.”	Innovation is a key corporate value at NB Power. The commitment to smart grid to allow NB Power to enable RASD programs and other efficiencies, as well as the partnership with Siemens demonstrates this commitment. Ref: Appendix 12 - smart grid/RASD

Stakeholder suggestions (number indicates votes by participant):	NB Power response:
Finance and rates structure 103. “A long-term plan that revealed the actual marginal cost of electricity to customers via prices would provide essential information for energy innovators to directing work to provide the greatest benefit.” 104. “Rate structure for industrial customers based on daily peak to shift demand” 3 105. “Preferential rates for large industrial users” 3 106. “Financial stability and rates lower than regional alternatives” 2 107. “Energy rates are competitive and affordable to all sectors of society.” 1 108. “Accelerate NBP debt repayments while interest rates are low.” 1 109. “Utilize cheap off season purchase power to replace nuclear” 1 110. “Fair and equitable prices for product that reflects the cost of the service with marginal price and cost included.” 111. “Stay competitive and supply to industry with best price.” 112. Ensure “Financial stability and a sustainable utility.” 113. “At a high level, be ‘light on our feet’ to respond to changes. At the same time, not only responding but creating opportunity (seem to be on good track with smart grid!)” 114. Create “equity in economic prosperity through de-concentration” of assets 115. “Ensure NB Power stays profitable.” 116. Ensure “appropriate rate structure.” 117. Be “pro-active innovative and efficient in providing energy in a fiscally responsive manner.” 118. “Provide incentives or preferential rates to industries and businesses that hire and maintain Certified Energy Managers so energy efficiency remains a corporate priority.” 119. “Key renewable sustainable generation including low, stable and predictable rates.” 120. “Create an NB Power clean tech venture capital fund to fund pilot projects in New Brunswick.” 121. “Look for profitable opportunities with neighbouring regions.” 122. “Adopt ‘price adders’ to reflect legitimate environmental costs in electric rates and remit proceeds from same to an independent body for use to promote environmental goals.”	Stable and sustainable finances are essential to an affordable and reliable supply of electricity. The IRP contributes to that financial stability in the long term. Ref: s.1.1 Initiatives within RASD will provide the ability to send price signals to customers, and NB Power will be exploring those options in the coming months. Ref: Appendix 12 - smart grid/RASD

Stakeholder suggestions (number indicates votes by participant):	NB Power response:
Reliability 123. Ensure a “resilient power system.” 124. “use tried and proven solutions.” 125. “Long term planning can drive an internet of distributed power generation that achieves resilience, reliability and sustainability.” 126. “Continue with well-balanced energy portfolio” 1 127. “Distribution system must be resilient reliable and sustainable” 1 128. “Ensure infrastructure supports integrity of new technology and innovation.”	Resiliency and reliability have been, and continue to be, important attributes of the power system. The load and resources balance and existing transmission system directly address these attributes ensuring the adequate supply and delivery of capacity and energy in the long term. Ref: s.3.3 and 3.4

Appendix 12: Smart Grid

NB Power has recently initiated steps towards integrating smart grid technologies into its electrical system with the goal to build Canada's first fully integrated 'energy internet', enabling all-way communications between customers and their homes, power plants, distribution systems and customers. NB Power plans to leverage to the extent possible the smart grid infrastructure for the deployment of programs specifically aimed at reducing the electricity demand during the coldest days of winter, i.e. at the time when electricity production costs are at their highest.

While such programs—commonly termed “demand response” programs—are designed to reduce and shift demand, particular attention will be paid to create a synergy with the initiatives laid out under the Electricity Efficiency Plan. This approach will enable the plan to maximize the benefits for households and businesses as well as optimize the deployment channels and costs of various energy conservation initiatives. By effectively incorporating demand response into the demand management and energy efficiency plan, NB Power will be joining a select group of North American leaders having an integrated demand side management plan. NB Power calls this strategy Reduce and Shift Demand, RASD.

What is a Smart Grid?

Smart Grid can be defined as an intelligent, self-managed electrical grid that leverages information obtained from strategically placed sensors to monitor its performance. Through the use of information technology, communication technology and operational technology, it is able to provide optimal, efficient and reliable grid performance under all operating conditions. Smart Grid involves the merging of the electrical infrastructure and the information/communication technology infrastructure. Once merged, these infrastructures can be leveraged to enable more efficient management of the electrical grid.

Transforming the current electrical grid so that it is more responsive and capable of meeting the needs of the future is an essential step and is expected to result in the following benefits to NB Power supply scenarios:

- integration of more wind and other intermittent renewable energy sources
- potential to enhance the economic and efficient dispatch of units to meet grid requirements.
- improved overall system efficiency.
- potential to defer new infrastructure to accommodate contingencies.
- customer empowerment.

There are a number of issues that influence the timing of the deployment of Smart Grid infrastructure. A regulatory framework will be required to allow NB Power to recover the investment through its rate base. The capital investment required to attain a mature Smart Grid environment is substantial. It will be necessary to future proof investments as much as possible to delay the infrastructure becoming obsolete.

In order to deliver the benefits associated with Smart Grid, enabling technologies and standards will need to evolve and will require collaboration between governments, utilities and manufacturers. The entrance of large players such as Google, IBM and Microsoft into the discussions has increased expectations and will further accelerate the evolution of technologies. Large investments in Smart Grid implementations in the U.S. and Canada will also assist in the evolution of necessary standards and technologies.

Role of the Smart Grid in this IRP

NB Power has recognized the long-term potential of Smart Grid to assist in realizing its new vision of “Sustainable Electricity”. As a result, NB Power has engaged in a number of pilots and continues to explore cost-effective opportunities in this area.

The following is an overview of how Smart Grid applications will affect NB Power’s IRP.

- NB Power continues to use technology to enhance its relationship with customers by offering more choices for interaction, as well as information that will allow customers to become more actively involved in their energy consumption. Through understanding how to use electricity more effectively and knowing their electrical consumption patterns, customers can get the maximum value from what they are paying for electricity.
- Smart Grid technologies will be used to integrate renewable energy sources such as wind and solar onto the grid. These sources are variable in nature and they require utilities to develop cost-effective ways to respond to ensure stability of the grid. One method that will be explored is working with customers on the delivery of mutually beneficial load control and energy management programs.
- Operational efficiencies will occur as two-way communications (with thousands of end points that monitor the status of the grid) are established. Improvements in restoration times during outages, more effective management of assets and improved service offerings to customers are examples of potential benefits.
- The information provided with the implementation of Smart Grid technology can be leveraged to increase load research capabilities used in rate design, load forecasting and cost of service studies. The results could lead to enhanced rate offerings that may be used to assist in managing an increasingly complex electrical grid.

Standards and enabling technologies necessary to successfully implement and leverage the opportunities offered by Smart Grid are currently immature but are evolving at a rapid pace. NB Power will engage in the evolution to a smarter grid in a prudent and businesslike manner at a pace that embraces the vision of "Sustainable Electricity."

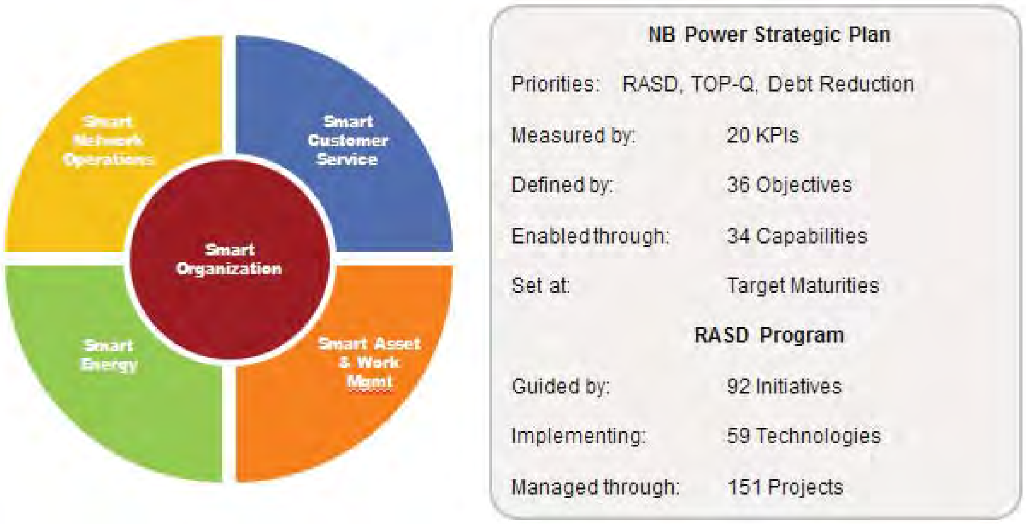
A smart meter is one of many components within the Smart Grid

Siemens Partnership

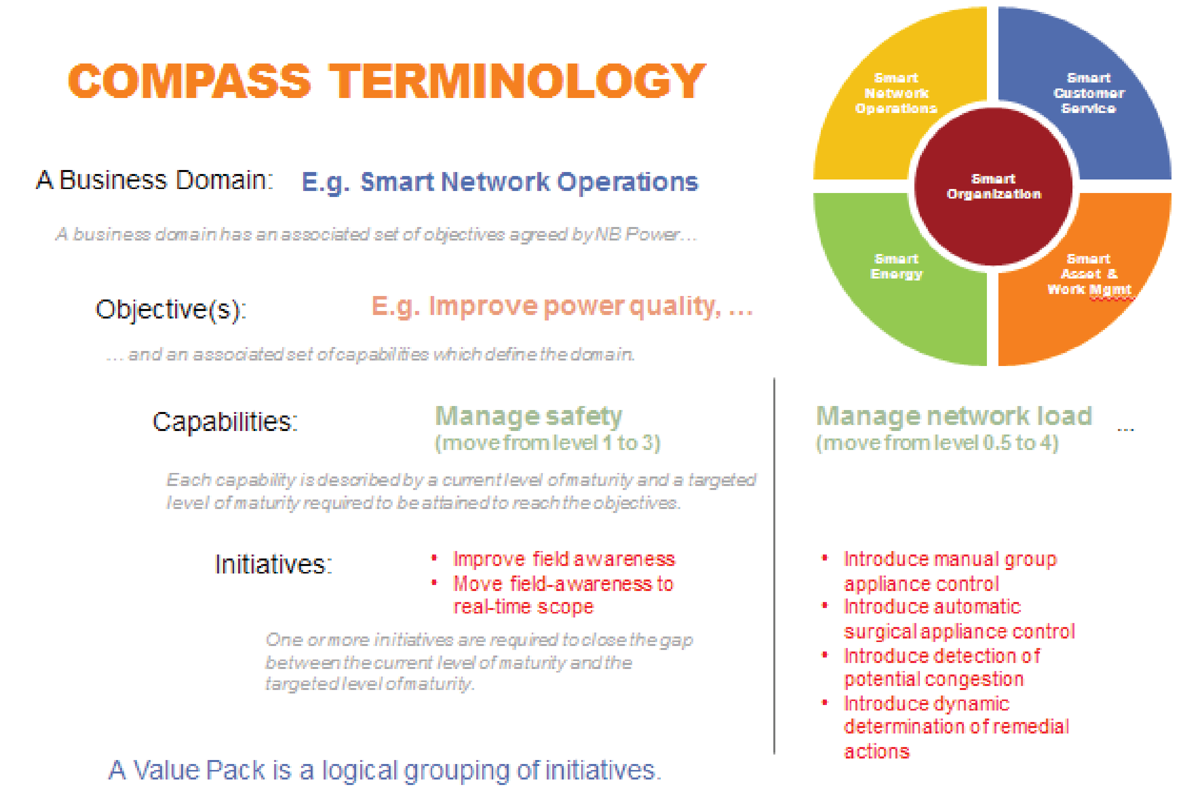
In 2012 NB Power began a 10-year program with Siemens to develop, implement and leverage smart grid capabilities in support of achieving its three strategic objectives: Reduce and Shift Demand, Top Quartile Performance, and Debt Reduction. The methodology being employed in the program is part of a comprehensive value framework from Siemens called Compass. The Compass framework takes a holistic view of organization across five domains:

- Smart Organization
- Smart Network Operations
- Smart Customer Service
- Smart Asset and Work Management, and
- Smart Energy.

THE COMPASS FRAMEWORK DIRECTLY SUPPORTS THE ATTAINMENT OF NB POWER'S GOALS

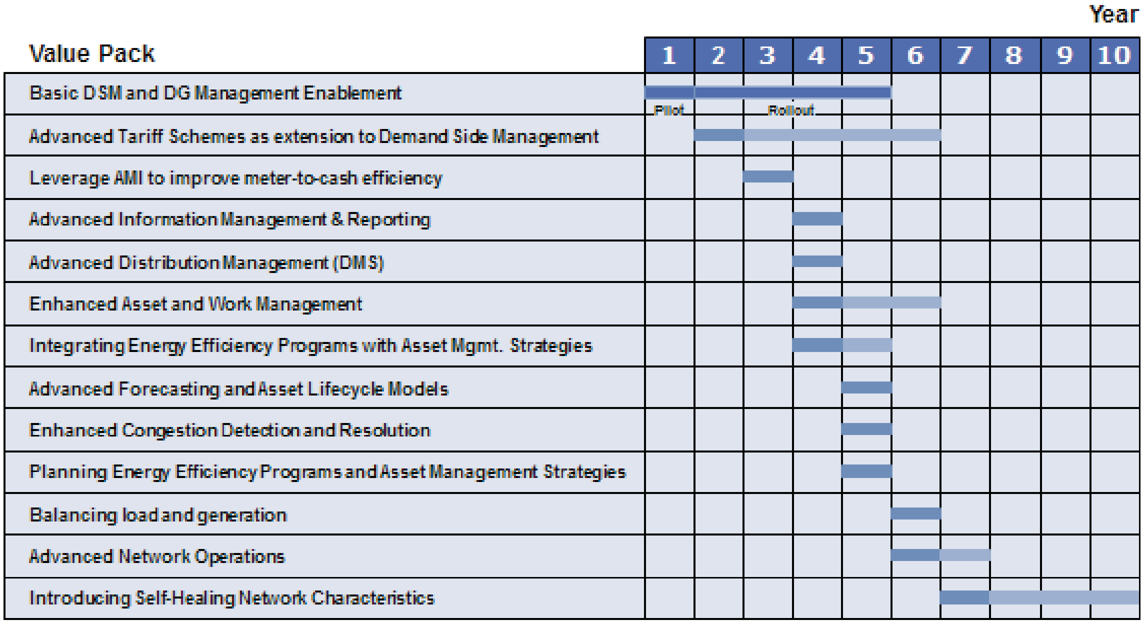


Each domain has associated objectives, measured by key performance indicators (KPIs), that directly relate to the three strategic objectives. Each domain is also defined by a set of capabilities. The capabilities are characterized by two maturity levels: one level is the current maturity level for a specific capability, and the second for the aspired or targeted level of maturity for that same capability. The Compass method sets an organization on a journey to complete initiatives and employ technologies to close the maturity gaps between current and aspired levels. By completing initiatives and deploying technologies the organization progresses toward becoming a smart grid-enabled organization with the capability of meeting its strategic objectives.



The Compass value framework is designed to progress the development of multiple organizational capabilities in parallel, enabling the organization to unlock value in both its internal operations and in the form of improved operations, increased efficiencies, and better information about the electricity grid and the customer's electrical load on the system. Improved service to customers and increased efficiencies are fundamental to sustainable electricity.

Value packs are logical groupings of initiatives that share similar technological requirements. The program has identified thirteen value packs of initiatives to be completed over the ten year program.



Completing value packs in sequence, and leveraging their associated synergies, is a key ingredient of the long-term success of the program. Value packs comprise both capability improvements (through initiatives) and the implementation and deployment of associated technologies. As an example, Value Pack 1 is comprised of the following initiatives and associated technologies.

Value Pack 1: Basic Demand Side Management and Distributed Generation Enablement

Initiatives	Technologies
Introduce DSM response predication based on historic response information (residential) *	• Smart Grid Backbone – Operational Data Store – Time Series Archive • Smart Grid Backbone – Integration – Visualization • SCADA – Control • Demand Response – Home Controller • Demand Response – C&I Controller • Decentralized Generation – Controller
Introduce schemes targeting individual customers with near real time response (residential) *	
Introduce prediction of C&I DSM request leveraging historic response information *	
Introduce improved management of C&I DSM resources based on near real time response measurement *	
Introduce a grid access policy for DG combined with a DG register	
Introduce network condition based (near real-time) DG control	
Introduce basic KPI system for asset class	
Introduce first joint standards covering information and operational technologies **	
Introduce on-demand reads by customers *	
Introduce a comprehensive approach to management of change *	

Overall, the NB Power smart grid program with Siemens brings efficiencies that are anticipated to produce significant impact both for the utility and the province. Highlights of the anticipated benefits are as follows:

- Contribution to the 2038 609 MW load reduction
- Facilitate a greater diversity of electricity supply options such as renewables
- Optimize the existing capacity
- Support customer lifestyle choices
- Utilize thermal storage opportunities accelerate debt reduction
- Lower Green House Gas emissions
- Minimize power disruptions through improved outage management
- Increase transmission capability
- Facilitate electric vehicle penetration

Telecommunications and the Smart Grid

As noted throughout this report, the electric power industry is experiencing significant pressures that are leading to noticeable improvements in the delivery of electricity. Addressing environmental issues, controlling costs and maintaining reliable networks are common themes for utility leaders. More specifically, some of the drivers for change include:

- more aggressive demand management programs
- smart grid technology such as smart meters and substation/distribution automation
- time of use or critical peak rates which lead to efficient use of electricity
- the desire for distributed generation
- the evolution of electric vehicles
- improvement of operational efficiencies with meter reading, real-time power outage management and asset management

One of the common requirements for these drivers is a strong and reliable two-way telecommunication network.

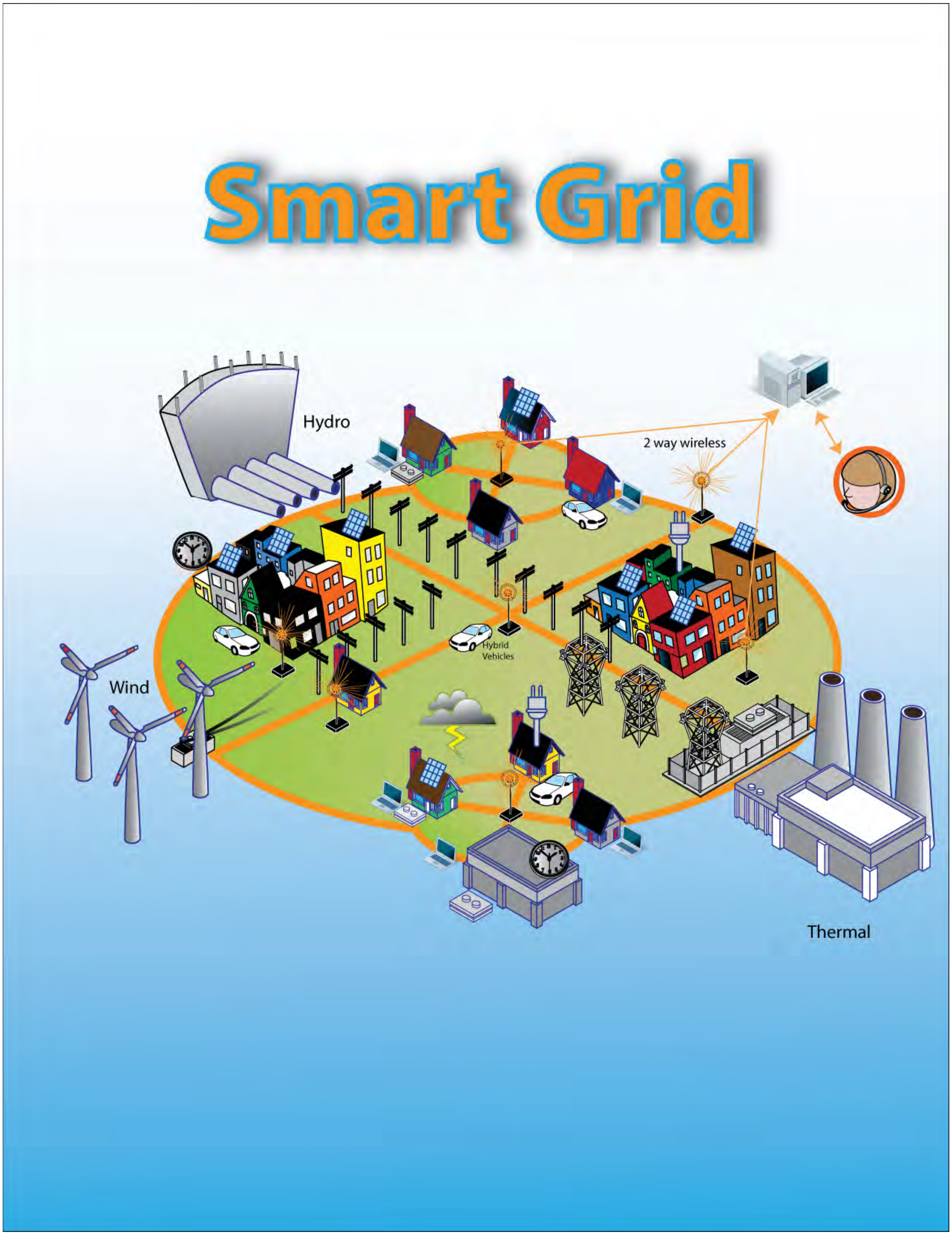
The telecommunication network at NB Power acts as the backbone for many business solutions. This invisible and reliable network keeps the business running smoothly. Examples of telecommunications used at NB Power include a provincial microwave network, a mobile radio network, Wi-Fi technology at Head Office, third party wireless service, radio frequency (RF) technology for meters and 900 MHz free spectrum radio bands. These technologies drive the following key business solutions:

- transmission line protection and control - microwave
- supervisory control and data acquisition (SCADA) - microwave
- two-way mobile radio communications - point to point mobile radio network

- phone system - microwave
- computer system - microwave
- workforce management - third party wireless network
- radio frequency meters - drive-by meter reading
- substation metering and breaker control

The existing telecommunications network at NB Power will need to evolve as Smart Grid technologies are implemented.

A Smart Grid and two-way communications of the future



Appendix 13: Glossary and Abbreviations

Biomass: Non-fossilized organic matter often used as fuel (e.g., wood waste).
British thermal unit (BTU): The amount of energy required to raise the temperature of one pound of water one degree Fahrenheit, equalling roughly 1000 kilowatts (kW).
Capacity: The maximum power that a generating unit, generating station or other electrical apparatus can supply, usually expressed in megawatts.
Carbon Dioxide (CO2): A colourless, odourless, non-poisonous gas that is a normal part of the ambient air. Carbon dioxide is also a product of fossil fuel combustion. It is a greenhouse gas that traps terrestrial (i.e., infrared) radiation and contributes to the potential for global warming.
Cogeneration: The simultaneous production of electrical or mechanical energy and useful heat energy from a single fuel source. For example, forest sector mills can burn wood waste in a boiler to generate electricity and use low-temperature steam from the generator in pulping processes.
Decommission: To take a piece of equipment such as a generation or transmission facility permanently out of service.
Demand: The size of any load, expressed in kilowatts (kW), averaged for a specified period of time.
Demand-Side Management: Actions that modify customer demand for electricity, helping defer the need for new energy and capacity supply additions.
Distributed Generation: Also referred to as DG, is a method of generating electricity from multiple small energy sources very near to where the electricity is actually used.
Distribution System: The poles, conductors and transformers that deliver electricity to customers. The distribution system transforms high voltages to lower, more usable levels. Electricity is distributed at 120/240 volts (V) for most residential customers and 120 to 600 V for the majority of commercial customers.
Economical Dispatch of Generating Units: The scheduling of power production as demand for electricity varies, according to the lowest cost generating sources available to the System Operator, given transmission limits and other constraints.
Electrical Energy: Electrical utilities sell electrical energy to their customers who, in turn, convert this energy into a desirable form — such as work, heat, light, or sound. Electrical energy is measured in kilowatt hours (kWh).
Energy: Quantity of actual power produced by a generating station over a period of time, measured in megawatt-hours (MWh).
Energy & Utilities Board (EUB): The provincial government's regulatory body through which all of New Brunswick's electricity and natural gas rate applications must be approved before rate increases can become implemented.
Energy Imbalance Service: The hourly difference between the actual and scheduled energy flow.
Federal Energy Regulatory Commission (FERC): A US agency that regulates the interstate transmission of natural gas, oil and electricity.

Fly Ash: Represents the finely divided particles of ash suspended in gases resulting from the combustion of fuel. Electrostatic precipitators are used to remove fly ash from the gases prior to the release from a power plant's stack.
Generator: A machine that converts mechanical energy — such as a rotating turbine driven by water, steam, or wind — into electrical energy.
Gigajoule (GJ): A measure of energy for natural gas equaling one billion joules or one million BTUs. One gigajoule of energy is equivalent to that provided by approximately 278 kilowatt hours of electricity or 30 litres of gasoline.
Gigawatt (GW): The unit of electrical power equivalent to one billion watts or one million kW.
Greenhouse Gas (GHG): Gases that trap heat in the atmosphere and are thought to contribute to global climate change, or the "greenhouse effect," including carbon dioxide (CO_2), methane (CH_4), nitrous oxide (N_2O) and sulphur hexafluoride (SF_6).
Hydroelectricity: Electricity produced by harnessing the power of falling water or streamflow.
Independent Power Producer (IPP): Operator of a privately owned electricity generating facility that produces electricity for sale to utilities or other customers.
Integrated System: An interconnected network of transmission lines, distribution lines and substations linking generation stations to one another and to customers throughout a utility's service area, but excluding isolated customers who are connected to freestanding generating plants.
Joule (J): A measure of energy for natural gas.
Kilowatt (kW): One thousand watts; the commercial unit of measurement of electric power. A kilowatt is the flow of electricity required to light 10 100-watt light bulbs.
Kilowatt Hour (kWh): The basic unit of electric energy equal to one kilowatt of power supplied to or taken from an electric circuit steadily for one hour.
Load: The amount of electric power delivered or required at any specific point or points on a system. The requirement originates at the energy consuming equipment of the consumer.
Load Forecasting: Determining an estimate of load requirements for some future time.
Megawatt (MW): Unit of electrical power to measure the generating capability of a generating station or the maximum demand of an electricity consumer
National Energy Board (NEB): A Canadian federal regulatory agency.
Natural gas: A fossil fuel made from hydrocarbons stored millions of years ago when plants and other materials were buried in the earth's crust. Composed mostly of methane — a colourless and non-toxic substance — natural gas creates virtually no unburned particles or smoke to pollute the atmosphere. The products of combustion are chiefly carbon dioxide and water.
Net Capacity Factor: The actual station generation of power to the grid in MW divided by the ideal maximum generation of power to the grid in MW possible.
Net Metering: A program that allows customers with their own generation facility to "bank" their surplus electricity with the electric utility. This banked surplus is then applied against the amount of electricity supplied by the utility.
Nitrogen Oxides (NOX): Gases consisting of one atom of nitrogen and varying numbers of oxygen atoms. Nitrogen oxides are produced, for example, by the combustion of fossil fuels in vehicles and electric power plants. In the atmosphere, nitrogen oxides can contribute to formation of photochemical ozone (smog) and impair visibility.

North American Electric Reliability Corporation (NERC): A US agency that establishes and enforces reliability standards for the bulk power system.
Open Access Transmission Tariff: Establishes non-discriminatory access to the transmission system for generators and customers inside and outside the province and generates revenues for Transco to operate and maintain the transmission system, based on the cost of providing services.
Outage: A planned or unplanned interruption of one or more elements of an integrated system.
Peak Capacity: The maximum amount of electrical power that generating stations can produce in any instant.
Peak Demand: The maximum instantaneous demand on a power system. Normally the maximum hourly demand.
Point-to-point Tariff: The fees charged for point-to-point service from one specific point to another. Typically this service is used for transporting energy through or out of the province.
Power grid: A number of interconnecting electrical power systems linking together electrical utilities and covering a large geographical area.
Power Purchase Agreements: Supply contracts between two parties for the supply of electricity.
Price Elasticity: A measure used in economics to show the responsiveness or elasticity of the quantity demanded of a good or service to a change in its price.
Renewable Portfolio Standard: Requirement that a certain amount of electricity sold in a competitive market includes some prescribed standard amount produced from renewable sources
Standard Service Supplier: The provider responsible for supplying adequate capacity and energy to meet customer demand for those customers not served by a competitive supplier.
Sulphur Dioxide (SO2): Belongs to a family of sulphur oxide gases (SOX) and is a colourless gas. It is formed from the sulphur contained in raw materials such as coal, oil and metal-containing ores used during combustion and refining processes. Flue gas desulphurization units are used to remove SO2 from the gases prior to the release from a power plant's stack.
System Average Interruption Duration Index (SAIDI): The average total duration of interruptions during the year.
System Average Interruption Frequency Index (SAIFI): The average number of times each customer on the distribution system is without power annually.
System Operator: An independent, not-for-profit entity that directs the operation of the electricity market maintains the long-term adequacy and reliability of the electricity system and administers the Open Access Transmission Tariff.
Transmission system: The towers, conductors, substations and related equipment involved with transporting electricity from generation source to areas for distribution — or to the power systems of out-of-province electrical utilities.

Abbreviations

AAR: Alkali-Aggregation Reaction
BTU: British Thermal Unit
CAD: Canadian dollar
CAPP: Canadian Association of Petroleum Producers
CFL: Compact fluorescent light
cfs: cubic feet per second
CH4: Methane (natural gas)
CMP: Central Maine Power
CO: Carbon monoxide
CO2: Carbon dioxide
CPI: Consumer Price Index
CT: Combustion turbine
EIA: Energy Information Administration
EPA: Environmental Protection Agency
EUB: Energy & Utilities Board
ETS: European Trading Scheme
FERC: Federal Energy Regulatory Commission
GHG: Greenhouse Gas
GJ: Gigajoule
GW: Gigawatt
GWh: Gigawatt hour
ha: hectares
HQ: Hydro Quebec
HVDC: High Voltage Direct Current
IBEW: International Brotherhood of Electrical Workers
IRP: Integrated Resource Plan
J: Joule
kt: Kilotonne
kV: Kilovolt
kW: Kilowatt
kWh: Kilowatt hour
LCOE: Levelized Cost of Electricity
LED: Light emitting diode
MECL: Maritime Electric Company Limited
Mt: Megatonne
MW: Megawatt
MWh: Megawatt hour
N2: Nitrogen gas
N2O: Nitrous oxide
NEB: National Energy Board
NERC: North American Electric Reliability Corporation
NOx: Nitrogen oxides
NPCC: Northeast Power Coordinating Council

NPV: Net present value
O&M: Operating and Maintenance
OPEC: Organization of Petroleum Exporting Countries
PCCI: Power Capital Cost Index
PEI: Prince Edward Island
PPA: Power purchase agreement
PSNH: Public Service of New Hampshire
RASD: Reduce and Shift Demand
REEP: Residential Energy Efficiency Program
ROE: Return on Equity
RPS: Renewable Portfolio Standard
SAIDI: System Average Interruption Duration Index
SAIFI: System Average Interruption Frequency Index
SARA: Species at Risk Act
SO2: sulphur dioxide
SOX: sulphur oxide gases
TPM: Total Particulate Matter
TW: Terawatt
TWh: Terawatt hour
TTC: Total Transfer Capability
USD: US dollar
WACC: Weighted Average Cost of Capital
WCI: Western Climate Initiative