Analysis of Proposed Development of the Maritime Link and Associated Energy from Muskrat Falls Relative to Alternatives

Prepared for:

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Power Advisory LLC

poweradvisoryllc.com
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Executive Summary

Introduction

In April 2010, the Nova Scotia Department of Energy (Department) released the *Renewable Electricity Plan* (*Plan*) which laid out a comprehensive program to move away from carbon-intensive electricity towards greener, more local and regional sources.[1] In addition to committing to having renewables provide 25% of all electricity by 2015, the *Plan* also specified a new goal of 40% renewable electricity by 2020. Nova Scotia indicated it would consider several alternatives to achieve the 40% renewable electricity supply including: (1) more intermittent sources such as wind, complemented by natural gas; (2) hydroelectric energy from Lower Churchill; or (3) more clean energy imported from other neighbouring provinces.

Six months after the release of the *Plan*, Emera Inc. (Emera) and Nalcor Energy (Nalcor) announced a major deal, reflected in a Term Sheet and thirteen subsequent formal agreements, for the Lower Churchill Project that would provide the province with at least .9 TWh of renewable energy per year.[2] The Term Sheet calls for the development of the Muskrat Falls Hydroelectric Project and the development of transmission infrastructure to deliver the project's output to the Island of Newfoundland and a portion ultimately to Nova Scotia. In return for bearing 20% of the cost of building the hydro facility and associated transmission facilities between Newfoundland and Nova Scotia, Nova Scotia ratepayers would receive 20% of the energy from Muskrat Falls for 35 years (the "Base Block", about 0.9 TWh per year). This would be supplemented by the "Supplemental Block", which would provide approximately 0.2 TWh/year for the first five years of the agreement. In addition to the Base and Supplemental Blocks, Nova Scotia Power (NS Power) would be able to purchase additional hydroelectric energy from Nalcor at market rates.

In September 2012, the Government of Canada finalized the *Reduction of Carbon Dioxide Emissions from Coal-Fired Generation of Electricity Regulations*[3] (*Federal Regulations*) that set a stringent performance standard, set at the emissions intensity level of natural gas combined cycle technology, for new and coal-fired units that reach the end of their assumed fifty year useful life. Under the *Federal Regulations*, Nova Scotia would be required to shut down six of its eight coal units by 2030.

The federal government and the Government of Nova Scotia have worked together to negotiate a draft *Equivalency Agreement*[4] for the above described coal-fired electricity GHG regulations. The main benefit of this *Equivalency Agreement* is that it will allow Nova Scotia to continue its current flexible and cost-effective approach to reducing GHG emissions from the electricity sector via its GHG, renewable energy and energy efficiency regulations. Beyond 2030 the Province of Nova Scotia will need to evaluate whether there is a need to extend the *Equivalency*

[1] http://www.gov.ns.ca/energy/renewables/renewable-electricity-plan/
[2] Appendix D reviews the technical terms associated with the measurement of energy and capacity.
[3] http://gazette.gc.ca/rp-pr/p2/2012/2012-09-12/html/sor-dors167-eng.html
[4] http://www.ec.gc.ca/lcpe-cepa/default.asp?lang=En&n=1ADECEDE-1

Agreement or revert to federal regulations. Regardless of which one is chosen, it is prudent to assume that further GHG emission reductions will be required post 2030.

Nova Scotia also has aggressive targets for the reduction of other emissions, including a 75% reduction in NS Power's sulphur dioxide (SO_2) emissions, a 44% reduction for NS Power's oxides of nitrogen (NO_x) emissions, and significant mercury emission reductions by 2020.

In addition Nova Scotia has outlined a number of strategic policy goals, many of which are promoted by the *Plan*, including promoting diversity and security of supply, facilitating a transition to cleaner energy, enhancing reliability and promoting flexible supply options to maintain regionally competitive supply prices.

Nova Scotia has distinct challenges associated with modifying its generation mix to best meet these different objectives while achieving these emission reduction requirements.

The purpose of this study is to assess the economic merits of the proposed development of the Maritime Link and the associated delivery of renewable energy from Muskrat Falls under the formal agreements negotiated between Nalcor and Emera relative to other options, while meeting all the regulatory requirements under the *Maritime Link Act*.[5]

Methodology and Assumptions

The analysis is based on a proprietary computer model that simulates the hourly operation of Nova Scotia's electricity system, including imports and exports, for each year in the 2015 to 2052 study period. The model estimates the difference in supply costs for three primary supply scenarios. The analysis focuses on differences in cost relative to the base case, rather than total costs. The model does not attempt to calculate all supply costs, only those costs that might change between scenarios. The three primary supply alternatives considered are:

- Participation in the Lower Churchill Project, including construction of the Maritime Link to bring power from Newfoundland to Nova Scotia.
- Negotiation of a contract with Hydro-Quebec, including paying a share of required transmission upgrades between Quebec and New Brunswick, and between New Brunswick and Nova Scotia. This contract is assumed to be for a similar term and a similar amount of electricity as the Lower Churchill contract, but based on market prices given other long-term contracts entered into by Hydro-Quebec relatively recently.
- Additional domestic wind and natural gas generation.

[5] Under the *Maritime Link Act* the Nova Scotia Utilities and Review Board (UARB) must determine if the project meets all of the following criteria:

(a) the project represents the lowest long-term cost alternative for electricity for ratepayers in the Province; and

(b) the project is consistent with obligations under the *Electricity Act*, and any obligations governing the release of greenhouse gases and air pollutants under the *Environment Act*, the *Canadian Environmental Protection Act* (Canada) and any associated agreements.

These represent a reasonable range of viable alternatives given the Province's renewable targets and stringent emission caps.

Analysis Results

The Lower Churchill scenario is less expensive than either of the two alternatives. On a net present value basis, as shown in Table ES- 1, the Lower Churchill scenario is projected to be $402 million less expensive (in 2017 dollars) than the Hydro-Quebec contract scenario, and $1.525 billion less expensive than the Domestic Generation scenario, over the 35-year life of the Lower Churchill Project contract (2017-2052). The net present value calculations are based on a discount rate of 6%. However, the constraints assumed in the model made it impossible to find a solution that met all emission caps in all years in the Domestic Generation scenario. It would probably be possible to overcome these constraints, but at considerable cost, so actual costs in this scenario (and the actual difference between this scenario and the Lower Churchill scenario) may be somewhat higher.

Table ES- 1: Relative Cost of Primary Supply Alternatives above the Cost of Lower Churchill

	Net Present Value ($ million, in 2017 $)
Hydro-Quebec Contract vs. Lower Churchill Project	$402
Domestic Generation vs. Lower Churchill Project	$1,525

Source: Power Advisory

The model was also run with a number of sensitivity cases which were intended to reflect a reasonable range of future market conditions. The purpose of the sensitivity cases is to identify factors which could potentially affect the conclusions of this analysis. Results of the sensitivity cases – i.e., the difference between the three primary supply alternatives in net present value terms – are shown in Table ES- 2. The Lower Churchill scenario was found to be the most cost-effective in all sensitivity cases. In comparing the Lower Churchill scenario to the two alternatives, the sensitivity cases with the greatest impact were the high market import capacity and high demand cases. Both of these sensitivity cases include an assumption that Nova Scotia would invest in whatever system improvements are required to allow up to 500 MW (rather than the base case assumption of 300 MW) to be imported over the Maritime Link at all times, and that such power would be available on a non-firm basis.

This analysis gives no credit to end use effects or the considerable strategic value to Nova Scotia of having a second major interconnection and a direct transmission path to what is likely to be 45 TWh of low variable cost non-emitting hydroelectric energy. Furthermore, the Maritime Link represents an alternative transmission path to Nova Scotia that avoids the relatively high Hydro-Quebec TransEnergie transmission tariff for such energy. This is likely to cause Nalcor to prefer to use the Maritime Link to access the New England market rather than the Hydro-Quebec TransEnergie transmission network, particularly given limits on firm transmission rights out of Quebec. With Nova Scotia on the transmission path to the larger New England market, it will have additional competitive supply options available to it that will lower costs and enhance competition.

Table ES- 2: Sensitivity Case Results

(NPV in $ million) Factor	Range	LCP vs. Hydro-Quebec Contract Low	High	LCP vs. Domestic Generation Low	High
Base Case		**$402**		**$1,525**	
ML Market Import Capability	0.8* / 3.5 TWh/year	$172	$1,173	$1,300	$2,296
Demand	±15%**	$693	$1,329	$1,094	$2,907
U.S. Gas Prices	±20%	$192	$523	$1,528	$1,642
N.S. Gas Prices	Domestic Supply	$539	n/a	$1,074	n/a
Carbon Prices	RGGI only	$314	n/a	$1,609	n/a
Coal Prices	±20%	$402	$384	$1,503	$1,617

*In the Low ML Market Import Capability case, market import capability varies from 1.5 TWh/year in 2018 (300 MW, minus the Base Block and Supplemental Block) to 0.8 TWh/year in 2040 (194 MW, minus the Base Block), then increases to 1.7 TWh from 2042 on (300 MW, minus the Base block).
**In the High Demand case, ML Market Import Capability is increased to 3.5 TWh/year (500 MW, minus the Base Block; slightly less while the Supplemental Block is available).

Source: Power Advisory

In addition, these analyses may be understating Lower Churchill's cost advantage because the assumptions regarding the other two alternatives may be optimistic. It is not clear that Hydro-Quebec would be interested in offering Nova Scotia a long-term contract; such a contract would provide dispatchability to the level assumed; Hydro-Quebec would not demand a premium for the assumed contract length, firm capacity, and renewable certification; or the cost of the required transmission capacity upgrades would be allocated to Nova Scotia in the favourable way assumed. Furthermore, while we have assumed that Hydro-Quebec receives the New England market price, to the degree that we haven't reflected the market price volatility realized in the New England market (and it is difficult for market models to fully capture such volatility) we may have understated the price that Hydro-Quebec would seek to receive. In fact, we have developed a Hydro-Quebec alternative when there is no evidence that it is interested or prepared to make a long-term sale to Nova Scotia of the form modeled. Therefore, it isn't clear that this is a viable or realistic alternative.

The greatest uncertainty in the Domestic Generation scenario is whether and if so, to what extent, additional gas generation on this scale would require substantial upgrades to the gas pipelines connecting Nova Scotia to the rest of eastern North America, once the gas in the Sable Island area runs out. Upgrading or twinning these gas lines could cost many hundreds of millions of dollars that would increase the cost of delivering gas to Nova Scotia. In addition, the costs of transmission upgrades and new gas-fired capacity that could be required to enable the level of wind penetration have not been fully assessed, but may be higher than the $10/MWh wind integration cost reflected in the analysis. These uncertainties, combined with the results of the sensitivity analyses, indicate that the Lower Churchill scenario is the most cost-effective of the three alternatives under the full range of possible market conditions evaluated, which represent a reasonable range of future market conditions.

The relative effectiveness of the three alternatives in meeting the provincial government's strategic policy goals was also assessed, as shown in Table ES- 3. This comparison suggests that the Lower Churchill Project best satisfies these goals.

- Domestic generation would best satisfy the diversity of supply objective because it would result in the addition of numerous additional supply resources that would be dispersed throughout Nova Scotia. The Lower Churchill Project would add only one primary additional supply resource initially, but it would be a fairly large new supply resource that isn't currently available to Nova Scotia. Furthermore, it would create a new transmission path that provides direct access to one of the largest hydroelectric projects in North America (Churchill Falls) and another major hydroelectric project (Gull Island) that is under development and is seeking markets. A contract with Hydro-Quebec would add an additional competitive supply resource under contract and strengthen the interconnection with New Brunswick, but the transmission path and the generation resources that would utilize it already are available to Nova Scotia so they don't represent a significant increase to the diversity of supply. Therefore, the Hydro Quebec purchase promotes this objective the least.

- The reliability goal is focused on adding another connection to electricity supplies to support the diversity objective. The Lower Churchill Project best satisfies this goal. Both the Lower Churchill Project and the Hydro–Quebec Contract would offer greater scheduling capability than the additional domestic supply alternative. We assumed that Hydro-Quebec would be willing to provide the same scheduling flexibility as provided by Lower Churchill. Committing energy and effectively capacity to Nova Scotia would reduce the energy that Hydro-Quebec would be able to deliver to New England, New York and other markets.

- Both the Lower Churchill and the Domestic Generation scenarios are likely to provide greater flexibility and offer greater price stability than a Hydro-Quebec purchase. However, the Domestic Generation scenario is forecast to yield costs that are significantly higher than the other two alternatives under all sensitivities and the base case. For other recent long-term transactions, Hydro-Quebec has sought a price that was indexed to ISO-NE market prices which are closely tied to natural gas pricing. Therefore, the Domestic Generation scenario performed the worst and the Hydro-Quebec contract doesn't perform as well as Lower Churchill.

- The Lower Churchill and Hydro-Quebec Contract scenarios perform equally well with respect to enabling achievement of GHG emission and other air pollutant reduction requirements and renewable energy commitments, except that there is uncertainty about whether imports from Quebec would qualify as renewable energy under Nova Scotia regulations. Nonetheless, we have assumed that NS Power and/or the Government would be able to resolve this issue in some manner as most of the electricity is from renewable sources. For the Domestic Generation scenario, none of the options considered in the model were able to meet the greenhouse gas emissions cap in the later years of the study period.

Table ES- 3: Ranking of Primary Supply Alternatives

	Lower Churchill Project	Hydro Quebec Contract	Domestic Generation
Diversity of Supply	2	3	1
Reliability	1	2	3
Flexible Supply to Maintain Competitive Prices	1	2	3
Achievement of GHG emission and other air pollutant obligations and renewable energy commitments	1	1	3

Relative ranking: 1 – best meets criteria; 3 – least meets criteria

1 Introduction and Purpose

In April 2010 the Nova Scotia Department of Energy (Department) released the *Renewable Electricity Plan* (*Plan*) which laid out a comprehensive program to move the province away from carbon-intensive electricity towards greener, more local and regional sources.[6] In addition to committing the province to having renewables provide 25% of all electricity by 2015%,[7] the *Plan* also specified a new goal of 40% renewable electricity by 2020. The 40% goal is now a commitment made through amendments to the *Electricity Act* in the spring 2012 house session. Nova Scotia indicated it would consider several alternatives to achieve the 40% renewable electricity supply including: (1) more intermittent sources such as wind, complemented by natural gas; (2) hydroelectric energy from Lower Churchill; or (3) more clean energy imported from other neighbouring provinces.

Six months after the release of the *Plan*, Emera Inc. (Emera) and Nalcor Energy (Nalcor) announced a major deal, reflected in a Term Sheet and thirteen subsequent formal agreements, for the Lower Churchill Project that would provide the province with at least 0.9 TWh of renewable energy per year. The Term Sheet calls for the development of the Muskrat Falls Hydroelectric Project and the development of transmission infrastructure to deliver the project's output to the Island of Newfoundland and a portion ultimately to Nova Scotia. In return for bearing 20% of the cost of building the hydro facility and associated transmission facilities between Newfoundland and Nova Scotia, Nova Scotia ratepayers would receive 20% of the energy from Muskrat Falls for 35 years (the "Base Block", about 0.9 TWh per year). This would be supplemented by the "Supplemental Block", which would provide approximately 0.2 TWh/year for the first five years of the agreement. In addition to the Base and Supplemental Blocks, Nova Scotia Power (NS Power) would be able to purchase additional hydroelectric energy from Nalcor at market rates.

Nova Scotia has also outlined a number of strategic policy goals, many of which are promoted by the *Plan*, including promoting diversity and security of supply, facilitating a transition to cleaner energy, enhancing reliability and promoting flexible supply options to maintain regionally competitive supply prices. These strategic policy goals and objectives for the Nova Scotia electricity system are discussed below.

1.1 Nova Scotia's Strategic Policy Goals

The *Plan* is the clearest statement of Nova Scotia's renewable electricity objectives. One of the cornerstones of the *Plan* was strengthening security through diversity.[8] Specifically, the plan seeks to ensure a more secure, stably-priced and reliable supply of electricity by diversifying fuel supply away from imported high carbon fossil fuels to more localized, low carbon and renewable energy sources.

[6] http://www.gov.ns.ca/energy/renewables/renewable-electricity-plan/

[7] This commitment was codified in Regulation by the *Renewable Electricity Regulations* (N.S. Reg. 155/2010).

[8] Nova Scotia Department of Energy, April 2010.

In addition to those goals and objectives outlined in the *Plan*, as part of the terms of reference provided for the performance of this study the government outlined several strategic policy goals including ensuring reliability; promoting flexible supply options to help stabilize and thus maintain regionally competitive electricity prices over the long term; and enabling achievement of GHG and air emissions obligations in a balanced manner.

To promote reliability the government favours electricity transmission and supply options that enhance regional connections and enhance the diversity of supply options. Recognizing the goal that it has set for renewable electricity and the price stability it can bring, the government also seeks an appropriate balance between firm and intermittent renewable resources and, everything else remaining equal, favours those renewable resources that can be scheduled day-ahead and assist in balancing supply and demand on a real time basis.

The *Plan* also recognized the importance of protecting the environment and ensuring sustainability. Nova Scotia currently has absolute caps on greenhouse gas emissions from the electricity sector and recently announced a draft *Equivalency Agreement* with the federal government to reduce greenhouse gas emissions from coal-fired electricity generation. This agreement recognizes that Nova Scotia's electricity sector greenhouse gas emissions will be subject to Nova Scotia and federal equivalency regulations instead of the federal coal-fired electricity regulation. The agreement requires Nova Scotia to achieve the same cumulative GHG reductions as would have been achieved under the federal regulation, but allows it to do so in a more cost-effective manner.

Nova Scotia is also committed to reducing air pollution from the electricity sector in a fashion that balances economic impact with good air quality outcomes:

- By 2020, sulphur dioxide (SO_2) emissions, will see a 75% reduction in NS Power's emissions relative to its initial SO_2 cap;
- By 2020, oxides of nitrogen (NO_x) emissions will see a 44% reduction for NS Power from a 2000 baseline;
- By 2020,mercury emissions will see a 84% reduction from the baseline;[9] and
- The Province of Nova Scotia is exploring with the federal government requirements for continued reduction in air pollutants post 2020 from the electricity sector.

Finally, the government seeks to manage costs for customers by promoting the development of diverse fuel supply options while minimizing capital costs due to premature facility closures or adding new facilities that otherwise would not be needed. This includes access to short-term market-priced cleaner energy such as natural gas-fired generation and reducing exposure to imported coal and oil prices by increasing reliance on local and/or regional, stably priced renewable electricity resources. This goal can be achieved by reducing dependence on any single energy source including coal, given Nova Scotia's significant reliance on it, and avoiding undue exposure to volatile natural gas prices directly or indirectly, recognizing that imports even if not from natural gas-fired generation are often priced on the basis of natural gas prices in New England given natural gas-fired generation's critical role in price setting in the region.

[9] http://www.nspower.ca/en/home/environment/environmentalaccountability/air/default.aspx

1.2 Purpose of Report

Nova Scotia has distinct challenges associated with modifying its generation mix to best meet these objectives while achieving these emission reduction targets. This report presents the results of an analysis of alternative generation scenarios that would achieve these emission reduction targets, security of supply objectives, while identifying the most cost-effective scenario over the longer-term.

The purpose of this study is to assess the economic merits of the proposed development of the Maritime Link and the associated delivery of renewable energy from Muskrat Falls under the formal agreements negotiated between Nalcor and Emera relative to other options while meeting all the regulatory requirements under the *Maritime Link Act*.[10]

The different scenarios were assessed with respect to their medium- to long-term cost effectiveness and based on how well they met the identified strategic policy goals and objectives.

1.3 Contents of Report

The general background and purpose of this report are discussed above within Chapter 1. In Chapter 2, we review the main legislative and regulatory requirements that guide this assessment. This includes the *Equivalency Agreement* and the *Plan*. Chapter 3 reviews the assumptions made as part of our analytical and modeling approach, including the demand forecast, planned and possible supply additions, fuel price forecasts, and required transmission infrastructure additions. It also describes the model itself, including its dispatch logic and constraints that were considered. Finally, Chapter 4 summarizes and reviews the results of the different generation scenarios considered, including relative scenario costs, emission levels, and the degree to which the various strategic policy goals and objectives are promoted.

[10] Under the *Maritime Link Act* the Nova Scotia Utilities and Review Board (UARB) must determine if the project meets all of the following criteria:

(c) the project represents the lowest long-term cost alternative for electricity for ratepayers in the Province; and

(d) the project is consistent with obligations under the *Electricity Act*, and any obligations governing the release of greenhouse gases and air pollutants under the *Environment Act*, the *Canadian Environmental Protection Act* (Canada) and any associated agreements.

2 Review of Nova Scotia's Renewable Electricity Plan and Equivalency Agreement

2.1 Review of *Renewable Electricity Plan*

Until 1999, Nova Scotia used coal mined within the province in its coal-fired generation stations, and fossil fuel resources made up more than 90% of the province's energy mix. Now, however, underground coal mining operations in the province are closed and NS Power sources most of its coal from international markets with a small amount from Nova Scotia open-pit sources. The *Plan* thus summarized its motivation as:

- Avoiding over-reliance on a single fuel source which weakens the province's energy security;
- Unbinding the electricity system from volatile and upward trending international fossil-fuel prices;
- Using more local resources to avoid the draining of wealth out of the province; and
- Reducing the negative impacts of fossil-fueled generation on Nova Scotians health and their environment.

As discussed, the *Plan* identified two specific renewable electricity targets: (1) a commitment of 25% renewable electricity by 2015; and (2) a 40% renewable electricity goal by 2020. The 25% commitment would more than double the renewable electricity share from 2009 levels. Many of the policies needed to achieve this target are currently being implemented. Achieving the 40% requirement may require expanded grid connections with Nova Scotia's neighbours, as well as a greatly expanded role for imported hydroelectric generation. The 2015 and 2020 commitments are discussed in greater detail in sections 2.1.2 and 2.1.3, respectively.

2.1.1 The Plan's Different Mechanisms

The *Plan* proposes to utilize several different mechanisms and generation sources in order to ease Nova Scotia's transition to new, localized, renewable energy sources. Some of these are discussed below.

Community-Based Feed-In Tariff (COMFIT) program
The Plan establishes a COMFIT that will encourage a range of renewable electricity projects which are widely dispersed throughout the province. This program calls for an expected 100 MW of renewable electricity projects connected to the distribution network. The COMFIT will also encourage the development of local renewable energy projects by municipalities, First Nations, co-operatives, and non-profit groups.

Biomass
Electricity produced from biomass will play a role in meeting the 2015 target, but generally, the Nova Scotia government is approaching the development of biomass resources for electricity production with caution. To ensure sustainability of biomass supply, new electricity generation from forest biomass is now capped at 350,000 dry tonnes above current uses (down from the

500,000 dry tonnes initially set in the *Plan*). Most of this biomass electricity will come from the NSPI project at Port Hawkesbury.

Tidal Energy

Nova Scotia plans to continue tidal energy research and development. This unique resource has the potential to make a significant contribution to the province's energy needs; the recently released *Marine Renewable Energy Strategy* (*Strategy*) estimates 2,400 MW of tidal energy could be extracted from the Minas Channel part of the Bay of Fundy alone and with only a small reduction (5%) in the tidal energy flow. To support tidal development, the province has set up a COMFIT for distribution-connected tidal projects. In addition, a developmental tidal FIT is under development, with the UARB expected to be set rates later this year.[11]

The *Strategy* has an objective of reaching commercially competitive technology and technical methods for permitting, deployment and retrieval toward the early part of the next decade with the deployment of 300 MW at a 50% capacity factor. This amount of electricity is material to the modeling work. However, under the assumptions used in the *Strategy*, this amount of tidal generation would only be used if it was cost-competitive with other clean/renewable sources. The timing on when such a source might become available and its implications on the need for other resource alternatives is uncertain and difficult to model.

For the purposes of this modeling then, with the exception of legacy tidal and small amounts of Feed-in Tariff in stream tidal, large-scale deployment of tidal is not specifically considered. However, when the technology does become competitive, it will likely displace additional renewable electricity supplies contracted on a spot market basis.

Lower Churchill Hydroelectric Project and the Maritime Transmission Link

The Lower Churchill Project is located on the Churchill River in Labrador and is considered one of the most attractive undeveloped hydroelectric projects in North America. First power from the project is expected in 2017 from the 824-MW Muskrat Falls phase with associated transmission to bring the energy to the island of Newfoundland. The second phase is the development of Gull Island (2,250 MW).The combined project (both Muskrat Falls and Gull Island) would provide almost 17 TWh of electricity per year. As part of the Muskrat Falls phase, the Maritime Link would be built, running from Bottom Brook in western Newfoundland to Cape Breton, Nova Scotia. This transmission link is a 500 MW, high voltage DC line that would tie into the existing Nova Scotia transmission grid, providing access to additional hydroelectric energy and by so doing enhance the diversity of energy supplies, and promote one of the Nova Scotia government's strategic policy objectives.

The Grid and Role of Natural Gas

Nova Scotia's local renewable resources – wind and tidal – are intermittent and not dispatchable, albeit tidal is highly predictable. To increase the grid's and the electricity supply system's capacity for such intermittent energy, Nova Scotia will continue to encourage the use of locally produced natural gas in fast-responding gas turbines that can be dispatched to respond to changes

[11] http://nsrenewables.ca/tidal-array-feed-tariff

in the wind and tides. In addition, new studies will lay the groundwork for upgrading the province's grid and its interconnection to neighboring provinces and the North American grid where cost-effective.

2.1.2 Meeting the 2015 Commitment (25% by 2015)

The Nova Scotia government has committed to law a 2015 target for 25% renewable electricity supply. As outlined in the *Plan*, this target is required to meet energy objectives for a more diversified and thus more secure electricity supply, greater stability of electricity prices and reduced dependence on imported fossil fuels, and improved air quality and reduced GHGs. Renewable resources offer greater long term price stability than fossil fuel resources given that there is little risk of escalation of fuel costs (except for biomass projects which draw upon fuels from the local area). The target will be achieved through a number of tools and mechanisms, including large- and small-scale projects, community-based renewable electricity projects, and requirements for biomass. These initiatives are already being implemented. To reach the 2015 renewable energy commitment of 25%, wind power will be the mainstay resource, along with heritage hydro and limited amounts of other renewable resources, mainly biomass.

Medium and Large-Scale Projects

Most of the new renewable energy needed to meet both 2015 and 2020 commitments will come from large-scale projects. The *Plan* expected the need for 600 GWh of energy from larger-scale projects in order to meet the 2015 law. However, due to a drop in demand, this number is now expected to be lower. Independent Power Producers competed for about 300 GWh in a bidding process that was administered by the Renewable Electricity Administrator (REA). Contracts were executed in August 2012 for three wind projects that are anticipated to provide about 350 GWh of renewable energy per year at approximately $75/MWh. This amount of additional electricity is now expected to be sufficient to meet the legal requirements for additional renewable electricity.

2.1.3 Meeting the 2020 Commitment (40% by 2020)

The goal of 40% renewable electricity supply by 2020 is now a legislative commitment in the *Electricity Act* and the amended *Environmental Goals and Sustainable Prosperity Act*, passed unanimously in the fall of 2012. The *Plan* specified that the approach to achieving targets will be flexible and adjust as nascent technologies mature and new technologies emerge. After 2015, Nova Scotia committed to consider several alternatives to achieve the 40% renewable electricity supply including: (1) more intermittent sources such as wind, complemented by natural gas; (2) hydroelectric energy from Lower Churchill; or (3) more clean energy imported from other neighbouring provinces.

Since the release of the *Plan* in April 2010, Emera and Nalcor have announced a major deal for the Lower Churchill Project that would provide the province with at least 0.9 TWh of renewable energy per year. A key aspect of this report is to evaluate the cost-effectiveness of the renewable energy that would be available as a result of this deal relative to viable alternatives during the life of the project.

The contractual arrangements that provide this energy are governed by detailed legal agreements between Emera, the parent of NS Power and Nalcor. The Term Sheet and formal agreements call for the development of Muskrat Falls and transmission infrastructure to deliver the project's output to the Island of Newfoundland and a portion ultimately to Nova Scotia. Nova Scotia would receive access to electricity through three distinct arrangements.

Nalcor would build the generating facilities at Muskrat Falls. Second, Emera and Nalcor will jointly develop transmission in Newfoundland and Labrador to enable the movement of Lower Churchill energy through the Province of Newfoundland and Labrador. This would be a joint venture that is owned by Nalcor (71%) and by Emera (29%).[12] The venture would establish a new, regulated transmission utility in Newfoundland and Labrador.

The agreements also call for the construction of subsea transmission between Newfoundland and Nova Scotia. In return for bearing 20% of the cost of building the hydro facility and associated transmission facilities, Nova Scotia ratepayers would receive 20% of the energy from Muskrat Falls for 35 years (the "Base Block", about 0.9 TWh/year). This subsea transmission (the Maritime Link) would be 100% owned by Emera through a regulated utility (Nova Scotia Power Maritime Link Inc.).

This entitlement to 20% of the energy from Muskrat Falls would be supplemented by the (Supplemental Block), which would provide approximately 0.2 TWh/year for the first five years of the agreement as compensation for the fact that the useful life of the transmission facilities is at least 50 years whereas the Base Block is only available for 35 years. NS Power would be able to purchase additional hydro energy from Nalcor at market rates (Market Electricity Block).

2.2 Greenhouse Gas and Air Pollutants

In September 2012, the Government of Canada finalized the implementation of a plan to reduce carbon dioxide (CO_2) emissions in the electricity sector by publishing the *Reduction of Carbon Dioxide Emissions from Coal-Fired Generation of Electricity Regulations* (*Federal Regulations).*[13] The *Federal Regulations* set a stringent performance standard for new and existing coal-fired units that have reached the end of their useful life, defined by the regulation as 50 years. The *Regulations* will require a transition from high-emitting coal-fired generation to lower emitting generation resources such as natural gas, renewable energy, or coal-fired generation with carbon capture and storage (CCS). The regulations will come into force in 2015. Under the *Federal Regulations* six out of Nova Scotia's eight coal units would be mandated to retire by 2030.

The Government of Canada recognized however that Nova Scotia has already been transforming its electricity sector from being highly dependent on coal to using cleaner sources of electricity by agreeing to enter into an equivalency agreement. This agreement will enable Nova Scotia to meet

[12] The ultimate ownership percentages may vary depending on the relative costs of Muskrat Falls and the Maritime Link.

federal electricity sector greenhouse gas emission targets using its own regulatory approach instead of the federal one, achieving the same emissions reductions in a more cost effective manner. The details of the draft *Equivalency Agreement* were published in *Canada Gazette I* on September 12, 2012. The agreement commits Nova Scotia to establish new GHG emission targets that extend from 2020 – 2030.

The Government of Canada also intends to develop regulations for natural-gas fired electricity. While it is not yet known what form these will take, it is safe to assume they will result in further GHG reduction obligations.

Beyond 2030 the Province of Nova Scotia will need to evaluate whether there is a need to extend the *Equivalency Agreement* or revert to federal regulations. Regardless of which one is chosen, it is prudent to assume that GHG emission reductions will be required post 2030. Nova Scotia's transformation away from sole reliance on fossil fuels to a more balanced mix with significant amounts of renewable energy sources, such as Lower Churchill, will also allow for further reductions to the regulated fleet caps of NO_X, SO_2 and mercury. The Province is exploring with the federal government requirements for continual reductions in air pollutants from the electricity sector.

3 Methodology and Assumptions

3.1 Introduction

The resource planning analysis presented in this chapter is based on a proprietary computer model that simulates the hourly operation of Nova Scotia's electricity system, including imports and exports, for each year in the 2015 to 2052 study period for a range of supply scenarios. The modeling attempts to stay within the range of known system operating constraints, but additional analysis would be necessary to verify transmission operating assumptions and intra-hour dispatch requirements. The analysis focuses on differences in supply costs relative to the base case, rather than total costs. The model therefore does not attempt to calculate all supply costs, only those costs that might change between scenarios. Three primary supply alternatives are considered:

- Participation in the Lower Churchill Project, including construction of the Maritime Link to bring power from Newfoundland to Nova Scotia;
- Negotiation of a long-term contract with Hydro-Quebec, including paying a share of required transmission upgrades between the Quebec and New Brunswick transmission networks, and between the New Brunswick and Nova Scotia transmission networks. This contract is assumed to be for a similar term and amount of electricity as the Lower Churchill contract, but based on a market price; or
- Additional domestic wind and natural gas generation, including enough wind (or other domestic renewable energy) to meet the province's emissions and renewable energy targets.

For a given supply scenario, the model estimates all of the costs that are considered "variable" – i.e., that might change between scenarios – including fuel costs, variable operating costs, pollution control costs, power purchase costs, and fixed operating and capital costs (but only if these may differ between scenarios). Costs that would be the same in every scenario – such as the fixed operating costs of plants that are assumed to remain in operation in all scenarios – are not considered. The model therefore makes no attempt to estimate the total cost to consumers of each scenario, only the differences between the scenarios. It is not possible to determine a specific impact on electricity rates with this analysis. The analysis compares the options and identifies the lowest cost option.

The rest of this chapter documents the assumptions used in the model.

3.2 Demand Assumptions

The base case load forecast is based on NS Power's *10 Year System Outlook 2012-2022 Report,*[14] updated based on events that have occurred since the release of this report in June 2012. The

[14] http://oasis.nspower.ca/site-nsp/media/Oasis/2012%2010%20Year%20System%20Outlook%20Report%20June%2029%202012.pdf

adjustments are based on the NS Power "2013 GRA Load Forecast Update".[15] The major changes are:

- A reduction in demand of 868 GWh per year. The main lost loads are the Bowater Mersey Paper Company Mill (690 GWh), which was closed in 2012, and the Imperial Refinery (78 GWh), which is at risk of closure in 2013; and

- An increase in demand of 1,138 GWh per year due to the Port Hawkesbury Paper Mill coming back on line.

A net adjustment of 270 GWh was applied to all years of the demand projection. It was assumed that post 2022 the load would remain flat at 10,832 GWh, as a result of aggressive conservation programs that would offset load growth.

Two sensitivity cases were run, with demand either 15% lower or 15% higher than the base case forecast in all years.

3.3 Common Supply and System Operation Assumptions

All scenarios included the following assumptions:

- Over 200 MWs of new wind capacity is assumed to be added by 2018, in addition to the existing 315 MW. The new capacity will be developed under the COMFIT program and through the REA RFP process;

- The only other new capacity assumed is the 60-MW Port Hawkesbury biomass plant (2013). The plant is assumed to be dispatchable, but with a high (90%) capacity factor;

- Two coal units will be effectively shut down by 2020 given unfavourable economics from reduced operating requirements: Lingan 2 at the end of 2014, and Lingan 1 by the end of 2020;

- Lingan 3 is must-run for system stability reasons, with a minimum output of 100 MW, except in the Lower Churchill scenario. The Maritime Link will supply power to Nova Scotia's transmission network at a point close to the location of the Lingan plant; and

- The remaining 6 coal units, the Tufts Cove steam units, and the diesel units are all assumed for modeling purposes to remain in operation (albeit at a much reduced level in the case of coal) throughout the study period.[16]

Tufts Cove 4 and 5 have been combined with the new Tufts Cove 6 to create a CCGT plant. Tufts Cove 1, 2 and 3 are dual-fuel gas/oil-fired steam units, with gas as their primary fuel. They are

[15] http://www.nsuarb.ca/index.php?option=com_content&task=view&id=73&Itemid=82 , Docket #: M04972 Exhibit #: N-103 PDF pages 6-8

[16] Given their staffing requirements a number of these coal units are likely to be retired and gas-fired generators with lower fixed operating costs built to replace them. However, significant differences aren't anticipated between the scenarios in the schedule for doing so.

assumed to be used primarily for load following and regulation services, with the required level varying with system demand, wind generation and hydro generation (hydro generation can substitute for the load following service that they provide to some extent). Any uncommitted capacity can be dispatched as required.

Because of its variability, wind can impose costs on the system in addition to direct contract payments or project costs. When the variability of wind output increases the overall level of variability in residual demand, additional operating reserves are required. When hydro units are at full output, fossil plants are often dispatched out of merit or at partial load so that they can quickly respond to fluctuations in wind output. These costs vary from system to system, but are generally higher in systems, like Nova Scotia's, which are smaller, more isolated and primarily rely more heavily on fossil generation rather than hydro for operating reserves. In the model, the cost of wind generation is increased by $10/MWh to account for these costs.[17]

While imports from New Brunswick have reached as much as 400 MW on very rare occasions, anything beyond 100 MW has the potential to affect system stability. The model assumes that the existing intertie can accommodate up to 100 MW in either direction at any time, though not on a firm basis. Imports and exports through this interconnection are priced based on hourly prices at the New Brunswick-Maine border, adjusted for transmission charges. This represents the opportunity cost for generators in New Brunswick, Quebec and New England.

Annual costs associated with capital investments were calculated based on NS Power's regulated return on equity (assumed to be 9.1% after tax), the corporate tax rate in Nova Scotia (31%), long term bond interest rate (assumed to be 5% for most capital investments, and 4% for the Lower Churchill Project because the federal government is providing the project with a loan guarantee), and debt:equity ratio (assumed to be 60:40 for most projects, and 70:30 for the Lower Churchill project due to the federal loan guarantee). Fixed operating and maintenance costs are also included in these annual costs. The net present value was based on a societal discount rate of 6%.

3.4 Primary Supply Alternatives

As discussed above, three "primary supply alternatives" were considered. These are considered "primary" because they are mutually exclusive, involve large blocks of power, and generally require very long-term planning.

3.4.1 Primary Supply Alternative A: Lower Churchill

This alternative includes Nova Scotia's participation in the Muskrat Falls phase of the Lower Churchill Project, which will include undersea transmission cables between Labrador and

[17] $10/MWh is the estimate in the 2009 IRP Update Basic Assumptions that were developed jointly by NS Power and UARB, and subsequently vetted by stakeholders. Estimates of wind integration costs vary widely, from less than $1/MWh to more than $10/MWh. For comparison, a 2008 BC Hydro study (http://www.bchydro.com/etc/medialib/internet/documents/info/pdf/2008_ltap_appendix_f3.Par.0001.File.2008_ltap_appendix_f3.pdf) estimated the total cost of wind integration to be between $9.9 and $11.0/MWh (in 2008 dollars) for a larger, hydro-based system. As the proportion of wind on the system increases the costs of integrating it also typically increases.

Newfoundland, and between Newfoundland and Nova Scotia. Nova Scotia will pay 20% of the project's costs, estimated to be $1.5 billion[18], plus financing costs during construction.

The Lower Churchill Project (which will be financed by Nalcor and Emera) has received a federal loan guarantee. There are a number of constraints on the amount of debt and type of debt that will be guaranteed by the federal government. The maximum proportion of debt is 70%. The total amount of debt must be amortized completely within 40 years after financial close of the project. The effect of the federal loan guarantee is to increase the debt:equity ratio to 70:30 and to reduce the interest rate by approximately 100 basis points. Both of these impacts serve to reduce the project's annualized capital cost. The value to Nova Scotia ratepayers in projected to be in excess of $100M.

This investment will entitle Nova Scotia to receive a "Base Block" of about 900 GWh/year (landed in Nova Scotia, after taking transmission losses into account) for 35 years beginning in 2017, on the following terms:

- "on peak", between the hours of 7 am and 11 pm, seven days a week;
- 154 MW of firm capacity delivered to Nova Scotia (which corresponds to approximately 170 MW generated at Muskrat Falls); and
- If transmission capacity is available, Nova Scotia can increase supply by up to 40 MW, to 194 MW, at any time during these hours, as long as the additional power is offset by a reduction to no less than 114 MW, resulting in exactly 2.46 GWh (154 MW x 16 hours) of supply every day.

Nova Scotia is entitled to take an additional 240 GWh/year as non-firm off-peak energy for five years at the rate of 199 MW during off-peak hours (11 pm to 7 am only, seven days a week), during winter months only (November through March). This is intended to compensate Nova Scotia for the fact that the contract is only for 35 years, whereas the hydro plant and transmission assets have an expected life of at least 50 years.

Nova Scotia is assumed to be responsible for a portion of the operating and maintenance costs of Muskrat Falls and the transmission lines. These are estimated to amount to 1% of capital costs, escalating with inflation after the first year. No other payment is assumed to be required for either the Base Block or the Supplemental Block.

The Lower Churchill Project will include a 500-MW undersea DC transmission link between Newfoundland and Nova Scotia, of which 154 MW (delivered to Nova Scotia) will be firm capacity dedicated to Nova Scotia. It is likely that Nova Scotia will be able to purchase additional power over the Maritime Link at market rates, though not necessarily on a firm basis. Importing too much power at any one time can be problematic for system operation; for example, it could increase the single largest contingency on the system and thus increase the operating reserve requirement. According to information provided by NS Power, the province's transmission

[18] The $1.5 billion was derived by the fact the Maritime Link represents 20% of the total cost of the Lower Churchill Project and Nalcor's DG3 estimate for the rest of the project is $6.2 billion. Therefore, the remaining 20% for the Maritime Link is approximately $1.5 billion

system can safely take up to 300 MW through the Maritime Link. Imports above this level would require significant system upgrades. It was therefore assumed that up to 300 MW could be imported at all times, including the Base and Supplemental Blocks (for example, if 194 MW of Base Block energy is being imported, an additional 106 MW of market-priced energy can be imported).

The possibility that imports could be limited by Newfoundland and Labrador's domestic requirements, rather than by the limitations of Nova Scotia's transmission system, was also considered. Initially, it is expected that Newfoundland and Labrador will consume approximately 40% of the annual output of the Muskrat Falls project; 20% will be supplied to Nova Scotia as the Base Block, and the remaining 40% will be exported at market prices (or supplied to Nova Scotia as the Supplemental Block in the first five years only). This represents approximately 1.8 TWh/year delivered to Nova Scotia for either its own consumption or export to New Brunswick and other markets. This, plus the Base Block of 0.9 TWh per year, amounts to slightly more than Nova Scotia could consume at a rate of 300 MW, so initially there should be ample energy from Muskrat Falls to meet Nova Scotia's need.

Over the long term, it is expected that Newfoundland and Labrador will consume most or all of Muskrat Falls' output (other than the Base Block committed to Nova Scotia). However, it is expected that Nova Scotia will be able to import power from other sources over the Maritime Link. The most certain of these sources is the existing 5,500-MW Churchill Falls project. Nova Scotia could purchase power from either Newfoundland (its 300-MW "Recall Block") or from Hydro-Quebec (which has the rights to the rest of the plant's output until 2041). Other possible sources include wind projects in Newfoundland and Labrador (which are expected to have much higher capacity factors, and therefore much lower costs per MWh, than wind projects in Nova Scotia and which could be shaped by the storage capacity at Muskrat Falls) and the 2,250-MW Gull Island project, near Muskrat Falls on the Churchill River. The most likely scenario, used in the base case, is that Nova Scotia will be able to import at least 300 MW over the Maritime Link throughout the study period, either from Muskrat Falls, Churchill Falls, Gull Island, or wind projects on Newfoundland.

The cost of these extra imports is assumed to be based on "netback" market prices at the time – i.e., prices at major hubs (ISO-New England's Mass Hub is used), adjusted for transmission charges and losses incurred or avoided in delivering the power to Nova Scotia instead of the alternative market. Initially, these imports are assumed to come from Muskrat Falls, but over time, as Newfoundland and Labrador's own electricity use increases and it consumes more of Muskrat Falls' output itself, the surplus available for sale is assumed to come from the Churchill Falls Recall Block. The alternative to selling surplus power from Muskrat Falls to Nova Scotia would be to sell it to New England. This would require transmission of the power through Nova Scotia and New Brunswick, and sale at the New Brunswick/New England border price. The most likely alternative to selling Recall Block power to Nova Scotia would be to transmit it through Quebec and New England. In the model, this results in a slightly higher netback price than that for Muskrat Falls power.

Imports over the existing intertie with New Brunswick are assumed to be priced in a similar way. It is assumed that all such imports will come from, or will be priced as if they came from, Quebec. Instead of selling this power to Nova Scotia, Hydro-Quebec could sell it to New England, presumably over the Phase I/II line that terminates at the Mass Hub in the ISO-New England market. (It could also be sold to New York, but New England prices tend to be higher.) Hydro-Quebec is therefore assumed to charge Nova Scotia a netback price equal to the Mass Hub price, minus the transmission charges and losses over the Phase I/II line, plus transmission charges and losses through New Brunswick.

The model includes a forecast of hourly prices at the Mass Hub, driven primarily by gas prices (including the cost of carbon allowances). The model adjusts these hourly prices as described above, and schedules the imports based on system demand and the cost of alternative sources of supply such as coal or gas generation in Nova Scotia.

All imports over the Maritime Link are assumed to count toward meeting Nova Scotia's 40% renewable energy targets, as they come from large hydro (or possibly wind) projects.

3.4.2 Primary Supply Alternative B: Hydro-Quebec

Instead of participating in the Lower Churchill Project, Nova Scotia could seek to import similar amounts of electricity from Quebec. There are a number of uncertainties with this assumption, including

- Price: It is not clear whether Hydro-Quebec would offer a discount or demand a premium over market rates for a firm long-term contract[19];
- Transmission: There is no available firm transmission capacity on either the Quebec-New Brunswick or the New Brunswick-Nova Scotia interties. A second New Brunswick-Nova Scotia intertie would need to be constructed to accommodate such purchases, and the Quebec-New Brunswick intertie would probably need to be upgraded as well[20];
- Availability: Although Hydro-Quebec appears to be open to long-term contracts,[21] they have not recently pursued a long-term contract with NS Power and they appear to favour market-based pricing rather than the long-term 35-year price certainty offered by Nalcor[22]; and

[19] While we have assumed that the Hydro-Quebec contract is market-based, Hydro-Quebec could claim that absent such a sales commitment it would be able to secure higher prices by selling into New York or at a different delivery point in New England and as such requires a premium over the market price.

[20] WKM Energy Consultants Inc., "An Assessment of the Costs and Issues Associated with the Delivery of a Purchase from Hydro Quebec", December 2012.

[21] Hydro-Quebec signed a long-term contract with a group of Vermont electric utilities which provides for a price which is tied to market prices for energy, capacity and various renewable attributes, if applicable. Hydro-Quebec is also seeking to sell energy and capacity as part of the development of the Northern Pass project in New Hampshire. A power purchase agreement for the sale of this power is reportedly under negotiation, but the general terms have not been disclosed.

[22] This could be explained by the significant transmission upgrade costs identified by WKM Energy Consultants which would adversely affect the economics of such a sale. Furthermore, it is likely that Hydro-Quebec views New England and New York as more attractive markets given their greater liquidity, whereas Nova Scotia effectively has one buyer.

- Status as renewable energy: While most of Hydro-Quebec's generation is from renewable sources (primarily hydro), it also operates fossil plants.

Nonetheless, in order to explore this option, the following assumptions were made:

- Hydro-Quebec is assumed to offer Nova Scotia 0.9 TWh/year of energy on the same terms as the Lower Churchill Base Block: dispatchable between 114 and 194 MW between 7 am and 11 pm each day, with a daily volume of 2.46 GWh;
- Upgrades that would secure sufficient transmission capacity between Quebec and Nova Scotia have been estimated to cost $1.05 billion, but Nova Scotia would not be entirely responsible for these costs.[23] Quebec and New Brunswick would derive some benefit from these upgrades (replacing aging infrastructure, improving system reliability, etc.) and would presumably share in the cost. WKM Energy suggested that Nova Scotia's share of these costs could be approximately $680 million. Of this, an estimated $150 million would be for work in Nova Scotia, which NS Power is assumed to pay for directly. Under New Brunswick's Open Access Transmission Tariff a portion of the remaining $530 million would be paid for through the firm transmission tariff that NS Power would pay (estimated to have a net present value of approximately $230 million), and the rest (calculated on a Net Present Value basis) through a direct capital contribution of $365 million.[24] The total up-front cost to Nova Scotia is therefore estimated to be $450 million. Nova Scotia would be responsible for O&M costs on those portions of the upgrades located in Nova Scotia (worth $150 million). O&M costs are assumed to be 1% of the original capital cost, increasing with inflation. The costs cited are assumed to be in real 2012 dollars (i.e., inflation adjustments would need to be added), but include financing during construction;
- This cost allocation is based on the assumption that Nova Scotia will secure 500 MW of firm transmission service between Quebec and Nova Scotia, with the cost based on estimates by WKM Energy Consultants Inc.[25] Power Advisory's hourly model assumes that this would give Nova Scotia the ability to import up to 600 MW (500 MW over the new intertie plus 100 MW of the existing intertie) from Quebec at any time – i.e., there are no constraints in Nova Scotia's transmission system that would limit such imports, and the capital expenditures discussed above would eliminate any constraints in New Brunswick's and Quebec's transmission systems;
- Rates for the imports are assumed to equate to market priced electric energy, with neither a discount nor a premium, using the same assumptions as those used for imports over the existing intertie in the Lower Churchill scenario. However, imports over the new 500-

[23] All estimates in this section are based on WKM Energy Consultants Inc., "An Assessment of the Costs and Issues Associated with the Delivery of a Purchase from Hydro Quebec", December 2012. Capital cost estimates are taken from Figure 6, p. 14, and exclude "Forecast O&M/OATT Costs".
[24] WKM Energy Consultants Inc., Figure 7, p. 15. The ultimate allocation of costs for these facilities would have to be negotiated among the various transmission owners based on anticipated benefits to the parties of these facilities. Therefore, it is uncertain whether Nova Scotia will receive as favourable a cost allocation as assumed.
[25] WKM Energy Consultants Inc., p. 20.

MW intertie are assumed to be delivered via the 500 MW of firm transmission service discussed above. Since the cost of this firm service is accounted for separately, New Brunswick transmission charges are not added to the netback price (though losses are). Imports over the existing 100-MW intertie are assumed to be priced factoring in New Brunswick transmission tariffs. Purchases under Nova Scotia's contract with Hydro-Quebec are assumed to flow over the 500-MW intertie and therefore are priced without factoring in New Brunswick transmission charges. Market-priced imports are assumed to flow 80% over the new intertie, and 20% over the existing intertie, and therefore would be subject to 80% of New Brunswick transmission charges;

- Nova Scotia is assumed to compensate Hydro-Quebec for the capacity revenue that Hydro-Quebec could otherwise have received for selling firm capacity into the New England Forward Capacity Market. This applies only to the 194 MW of firm capacity under contract; and
- Imports from Quebec are assumed to count toward meeting Nova Scotia's 40% renewable energy target, although there is no assurance of this at this point. Almost all of Quebec's generation is from renewable sources (mostly hydro, with some wind and biomass) but there is also some fossil generation. It is assumed that the contract will include arrangements, at no additional cost, to certify that the power sold to Nova Scotia comes exclusively from renewable sources.

We have employed what we believe are realistic assumptions for a contract with Hydro-Quebec. However, they could prove optimistic. We believe that it is unlikely that we have overstated the price that Hydro-Quebec would seek since there would be little reason for them to sell at a price below what they could otherwise receive without a contract, and we have not included premiums for firm energy, dispatchability or renewable energy. For example, there are likely to be periods when the power is more valuable in other markets than New England (e.g., New York or within Quebec itself during peak winter conditions) which we have not considered. In the past, Hydro-Quebec contracts have included recall provisions that allow the capacity to be used in Quebec during peak winter conditions. Given that the New England market is summer-peaking this is less of an issue for sales to New England than for sales to Nova Scotia which is also winter-peaking.

3.4.3 Primary Supply Alternative C: Domestic Generation

The third primary alternative is increased domestic generation. This will require additional renewable generation (assumed largely to be wind, for reasons discussed below) in order to meet the province's 40% renewable electricity target. An additional 450 MW of wind capacity (in addition to the 315 MW of existing capacity and over 200 MW of planned capacity) would be needed to meet the target under the base case demand forecast. For modeling purposes, all of this new wind capacity is assumed to come into service at the beginning of 2020, but in practice, it would probably be phased in over several years. The costs of transmission upgrades and new gas-fired capacity that could be required to enable this level of wind penetration have not been fully assessed, but may be higher than the $10/MWh wind integration cost reflected in the analysis. In addition, we have not considered the potential cost of whether additional gas generation on this scale would require substantial upgrades to the gas pipelines connecting Nova Scotia to the rest of eastern North America, once the gas in the Sable Island area runs out. Upgrading or twining these gas lines could cost many hundreds of millions of dollars.

3.5 Energy Price Assumptions

The table below shows the energy prices assumed in the base case. “NS Gas” refers to the burnertip cost of gas in Nova Scotia. “NE Carbon” refers to carbon allowance prices assumed to apply to fossil generation in New England; no carbon pricing is assumed in Nova Scotia since the province is achieving its emission targets through regulated emission caps. “NE Energy” is the average annual electricity Day-Ahead Locational Marginal Price at Mass Hub, and “NE Capacity” is the value of capacity in ISO-New England’s Forward Capacity Market.

Fossil fuel prices are based on the U.S. Energy Information Agency’s (EIA’s) forecasts (as reported in their *Annual Energy Outlook*, 2013 Early Release). The EIA’s forecast extends through 2040. For the 2041-2052 period, prices are assumed to increase with inflation. The EIA’s forecasts have been adjusted for delivery to Nova Scotia as appropriate. The adjustments include:

- $0.75/MMBtu for the difference between Dracut and Henry Hub gas prices;
- Gas transmission and delivery costs between the Dracut gas hub and Nova Scotia burnertip of $1.35 per MMBtu plus 1.8% losses. Gas is assumed to flow from Dracut to Nova Scotia, so Nova Scotia prices are higher;
- $2.40/MMBtu for the difference between the average cost of all steam coal for power generation in the U.S. (as forecast by the EIA) and low-sulphur coal delivered in Nova Scotia;
- A 25% difference between delivered coal and pet coke prices; and
- A $3.00/MMBtu difference between the average cost of distillate fuel oil for power generation in the U.S. (as forecast by the EIA) and burnertip diesel prices in Nova Scotia.

All adjustments are in constant 2012 US dollars, and are escalated with inflation. They are based on Power Advisory estimates.

Nova Scotia is not assumed to charge or participate in any carbon allowance pricing or CO_2 credit programs, so the carbon allowance costs apply only to New England. They affect the cost of generation in New England, which in turn affects the electricity prices used in valuing imports and exports. Carbon allowance prices are based on Power Advisory’s internal estimates. Prices through 2019 assume the only program in effect is the Regional Greenhouse Gas Initiative (RGGI). A U.S.-wide carbon pricing program is assumed to come into effect in 2020, similar to that proposed in the Waxman-Markey bill but with substantially lower prices.

Table 1: Base Case Fuel Price Assumptions

	NS Coal	NS Pet Coke	Dracut Gas	NS Gas	NS Diesel	NE Carbon	NE Energy	NE Capacity
	$/MMBtu	$/MMBtu	$/MMBtu	$/MMBtu	$/MMBtu	$/tonne	$/MWh	$/kW-yr
2017	$5.43	$4.07	$4.98	$6.58	$27.25	$2.21	$46.48	$43.70
2018	$5.55	$4.16	$5.38	$7.01	$28.21	$2.25	$49.61	$50.37
2019	$5.66	$4.25	$5.59	$7.26	$29.25	$2.30	$51.37	$59.17
2020	$5.81	$4.36	$5.81	$7.51	$30.29	$11.12	$56.61	$68.31
2021	$5.97	$4.47	$6.08	$7.81	$31.40	$11.34	$58.86	$77.79
2022	$6.14	$4.61	$6.47	$8.25	$32.53	$11.57	$62.04	$82.75
2023	$6.31	$4.73	$6.85	$8.67	$33.73	$11.80	$65.13	$84.40
2024	$6.48	$4.86	$7.13	$8.99	$34.96	$12.03	$67.51	$86.09
2025	$6.65	$4.99	$7.38	$9.28	$36.29	$12.27	$69.67	$87.81
2026	$6.83	$5.12	$7.73	$9.67	$37.58	$12.52	$72.55	$89.57
2027	$7.01	$5.26	$7.99	$9.97	$38.93	$12.77	$74.75	$91.36
2028	$7.20	$5.40	$8.32	$10.34	$40.33	$13.03	$77.53	$93.19
2029	$7.39	$5.54	$8.60	$10.67	$41.78	$13.29	$79.92	$95.05
2030	$7.60	$5.70	$8.92	$11.03	$43.24	$13.55	$82.58	$96.95
2031	$7.79	$5.84	$9.30	$11.45	$44.74	$13.82	$85.74	$98.89
2032	$7.99	$5.99	$9.63	$11.83	$46.26	$14.10	$88.52	$100.87
2033	$8.19	$6.15	$10.04	$12.29	$47.93	$14.38	$91.91	$102.89
2034	$8.41	$6.31	$10.66	$12.96	$49.72	$14.67	$96.82	$104.95
2035	$8.65	$6.49	$11.33	$13.68	$51.65	$14.96	$102.14	$107.05
2036	$8.88	$6.66	$12.16	$14.58	$53.68	$15.26	$108.69	$109.19
2037	$9.12	$6.84	$12.98	$15.46	$55.76	$15.57	$115.12	$111.37
2038	$9.36	$7.02	$13.89	$16.43	$57.60	$15.88	$122.23	$113.60
2039	$9.60	$7.20	$14.46	$17.05	$59.81	$16.20	$126.83	$115.87
2040	$9.85	$7.39	$15.18	$17.83	$61.99	$16.52	$132.50	$118.19
2041	$10.05	$7.54	$15.48	$18.18	$63.23	$16.85	$135.15	$120.55
2042	$10.25	$7.69	$15.79	$18.55	$64.49	$17.19	$137.86	$122.96
2043	$10.45	$7.84	$16.11	$18.92	$65.78	$17.53	$140.61	$125.42
2044	$10.66	$8.00	$16.43	$19.30	$67.10	$17.88	$143.42	$127.93
2045	$10.88	$8.16	$16.76	$19.68	$68.44	$18.24	$146.29	$130.49
2046	$11.09	$8.32	$17.09	$20.08	$69.81	$18.60	$149.22	$133.10
2047	$11.32	$8.49	$17.44	$20.48	$71.20	$18.98	$152.20	$135.76
2048	$11.54	$8.66	$17.78	$20.89	$72.63	$19.35	$155.25	$138.47
2049	$11.77	$8.83	$18.14	$21.31	$74.08	$19.74	$158.35	$141.24
2050	$12.01	$9.01	$18.50	$21.73	$75.56	$20.14	$161.52	$144.07
2051	$12.25	$9.19	$18.87	$22.17	$77.07	$20.54	$164.75	$146.95
2052	$12.49	$9.37	$19.25	$22.61	$78.62	$20.95	$168.05	$149.89

Source: EIA and Power Advisory

Six sensitivity cases are run on these fuel and carbon prices:

- 20% lower gas prices;
- 20% higher gas prices;
- Substantial domestic natural gas supply in the Maritimes, such that power plants are charged the netback price (the Dracut price minus the gas transmission charges and losses that gas suppliers would pay to deliver their product to Dracut). The Nova Scotia price is therefore lower than the Dracut price;
- No national carbon pricing or CO_2 credit program: New England carbon prices from 2020 on are based on RGGI (around $2 per metric tonne in 2012 dollars);

- 20% lower coal prices; and
- 20% higher coal prices.

3.6 Environmental Constraints

The Table 2 shows the emission caps and renewable energy requirements that are used in the model.

Table 2: Environmental Constraints

	Greenhouse Gases (million tonnes of CO_2e)	Sulphur (tonnes)	Mercury (kg)	Nitrogen Oxides (kg)	Renewables (% of consumption)
2017	8.28	60,900	60	19,228	25%
2018	8.02	60,900	58	19,228	25%
2019	7.76	60,900	47	19,228	25%
2020	7.50	36,250	35	14,955	40%
2021	7.20	36,250	35	14,955	40%
2022	6.90	36,250	35	14,955	40%
2023	6.60	36,250	35	14,955	40%
2024	6.30	36,250	35	14,955	40%
2025	6.00	28,000	35	11,000	40%
2026	5.70	28,000	35	11,000	40%
2027	5.40	28,000	35	11,000	40%
2028	5.10	28,000	35	11,000	40%
2029	4.80	28,000	35	11,000	40%
2030	4.50	20,000	30	8,000	40%
2031	4.39	20,000	30	8,000	40%
2032	4.28	20,000	30	8,000	40%
2033	4.16	20,000	30	8,000	40%
2034	4.05	20,000	30	8,000	40%
2035	3.94	20,000	30	8,000	40%
2036	3.83	20,000	30	8,000	40%
2037	3.71	20,000	30	8,000	40%
2038	3.60	20,000	30	8,000	40%
2039	3.49	20,000	30	8,000	40%
2040	3.38	20,000	30	8,000	40%
2041	3.26	20,000	30	8,000	40%
2042	3.15	20,000	30	8,000	40%
2043	3.04	20,000	30	8,000	40%
2044	2.93	20,000	30	8,000	40%
2045	2.81	20,000	30	8,000	40%
2046	2.70	20,000	30	8,000	40%
2047	2.59	20,000	30	8,000	40%
2048	2.48	20,000	30	8,000	40%
2049	2.36	20,000	30	8,000	40%
2050	2.25	20,000	30	8,000	40%
2051	2.25	20,000	30	8,000	40%
2052	2.25	20,000	30	8,000	40%

Source: Nova Scotia Department of Energy and Nova Scotia Department of Environment

The greenhouse gas caps are based on current regulations for sulphur, mercury and NOx emission and renewable energy requirements through 2020, and the greenhouse gas emission caps under the *Equivalency Agreement* through 2030. For emission caps past 2020 (2030 for greenhouse gases), Nova Scotia's Department of Environment provided estimates. The greenhouse gas emission caps assume a gradual decline through 2050. The sulphur, mercury and NO_x emission caps assume decreases in 2025 and 2030, with no further changes through the study period. Renewable requirements are based on generation as a percent of sales before losses.

Assumptions about the pollutant content of fuel are shown in the following table.

Table 3: Pollutant Content of Fuels

	Coal	Pet Coke	Natural Gas	Diesel
CO_2 (tonnes/MMBtu)	0.098	0.111	0.053	0.073
Sulphur (kg/MMBtu)	0.490	3.597	0.000	0.001
Mercury (grams/MMBtu)	0.0013	0.0016	0.0000	0.0001

Source: Power Advisory

Pet coke carbon emissions include the effects of burning limestone (which reduces sulphur emissions). The coal units remove 5% of sulphur through electrostatic precipitation.

Carbon and sulphur caps are met by adjusting dispatch (coal vs. gas vs. imports). Mercury caps are met by adjusting the level of powdered activated carbon (PAC) feed; costs and mercury removal rates were provided by NS Power. The renewable requirement is easily met in the Lower Churchill and Hydro-Quebec primary supply alternative scenarios; in the scenario with neither, additional wind capacity is added as required. The model reports NO_x emissions, but does not have a mechanism to optimize dispatch to meet the cap.

In some years in some scenarios, the model results show either greenhouse gas or sulphur emissions falling below the allowable caps. In practice, NS Power would very likely adjust its fuel mix to comply with the regulatory caps to the extent that this would reduce system costs. For example, it might use medium- or high-sulphur coal, or more pet coke. More sulphur in the fuel would affect the mercury abatement system, probably increasing PAC feed costs.

4 Modeling Results

4.1 Comparison of Primary Supply Alternatives

On a net present value basis over the 35-year life of energy deliveries under the Base Block, the Lower Churchill scenario is projected to be $402 million less expensive (in 2017 dollars) than the Hydro-Quebec contract scenario, and $1.525 billion less expensive than the Domestic Generation scenario. The net present value calculations are based on a societal discount rate of 6%.[26] However, the constraints assumed in the model made it impossible to find a solution that met all emission caps in all years in the Domestic Generation scenario, so actual costs in this scenario (and the actual difference between this scenario and the Lower Churchill scenario) may be somewhat higher. This is discussed in more detail below.

This analysis gives no credit to end use effects or the considerable strategic value to Nova Scotia of having a second major interconnection and a direct transmission path to what is likely to be 45 TWh of low variable cost non-emitting hydroelectric energy. Furthermore, the Maritime Link represents an alternative transmission path to Nova Scotia that avoids the relatively high Hydro-Quebec TransEnergie transmission tariff for such energy. Therefore, Newfoundland and Labrador will likely prefer accessing the ISO-NE market through Nova Scotia. This could result in higher transmission revenues for NS Power that could reduce its overall transmission tariff to the benefit of Nova Scotia customers. With Nova Scotia on the transmission path to the larger New England market, it will have additional competitive supply options available to it that will lower costs and enhance competition.

In addition, these analyses may be understating Lower Churchill's cost advantage because the assumptions regarding the other two alternatives may be optimistic. While we have assumed that Hydro-Quebec receives the New England market price, to the degree that we haven't reflected the market price volatility realized in the New England market (and it is difficult for market models to fully capture such volatility) we may have understated the price that Hydro-Quebec would seek to receive. In fact, we have developed a Hydro-Quebec alternative when there is no evidence that it is interested in or prepared to make a long-term sale to Nova Scotia of the form modeled. Therefore, it isn't clear that this is a viable or realistic alternative. The greatest uncertainty in the Domestic Generation scenario is whether additional gas generation on this scale would require substantial upgrades to the gas pipelines connecting Nova Scotia to the rest of eastern North America, once the gas in the Sable Island area runs out. Upgrading or twining these gas lines could cost many hundreds of millions of dollars. These uncertainties, combined with the results of the sensitivity analyses, indicate that the Lower Churchill scenario is the most cost-effective of the three alternatives under the full range of possible market conditions evaluated which represent a reasonable range of future market conditions.

[26] A discount rate is similar to an interest rate, but it is used to calculate the present value of future costs and benefits spread over multiple years. "Societal" discount rates are used to value costs and benefits to society as a whole – in this case, to all of Nova Scotia's ratepayers – rather than costs and benefits to an individual or a corporation. Societal discount rates are usually lower than regular discount rates, because society as a whole is assumed to put greater value on long-term impacts than private investors do.

The greenhouse gas emission targets are met in all years in all scenarios, except the final few years of the Domestic Generation scenario, where none of the options considered in the model were able to meet all criteria. Adding more wind capacity is both expensive and ineffective in reducing GHG emissions, because much of the additional wind generation occurs at times when the system already has surplus supply. One contributing factor is that at least one of the Lingan units must be run at all times to maintain system stability. This alone accounts for over a quarter of allowable GHG emissions in 2048 on. Alternatives are available, but they tend to be expensive; for example, replace Lingan with a gas-fired CCGT in the same area would require substantial gas transmission upgrades.

The sulphur emission caps can be met in all years by adjusting the fuel mix to include less pet coke (which is high in sulphur) and more low-sulphur coal. In several years, the table indicates that sulphur emissions would be well below the cap. In reality, NS Power would almost certainly adjust the fuel mix in these years to use less low-sulphur coal and more medium-sulphur coal, in order to minimize supply costs. There are tradeoffs between reducing costs by burning higher-sulphur fuels, and increasing mercury abatement costs due to higher sulphur levels in the flue gas. The model did not attempt to simulate this complex cost optimization process, because the net impact on costs would be too small to significantly affect the results of this study.

The cap on mercury emissions is met exactly by varying PAC feed levels.

NOx caps are exceeded by small margins in some years, particularly between 2030 and 2040. The model calculates NOx emission levels but does not have a mechanism to reduce them. In reality, NOx emissions could be reduced at moderate cost by installing or upgrading equipment in the existing and/or new gas plants.

The Lower Churchill and Hydro-Quebec Contract scenarios exceed the 40% renewable energy target in all years, because both assume that market imports will come primarily from large hydro plants in Labrador or Quebec, and that most or all of this energy will qualify as renewable for purposes of achieving the 40% target. In the Domestic Generation scenario, sufficient wind is developed to meet the 40% target.

4.2 Sensitivity Case Results

As well as the base case described above, the model was run with the following sensitivity cases:

- Maritime Link market import capability, assumed in the Base Case to be 1.7 TWh/year (i.e., 300 MW at all times, minus the Base Block; in the first five years, the Supplemental Block also needs to be taken into account, so only 1.5 TWh/year of market imports is possible during this period)
    - Low: Electricity available for purchase at market rates from Newfoundland falls from 1.5 TWh/year in 2018 to 0.8 TWh/year by 2040 (i.e., 194 MW at all times minus the Base Block). The limitation is assumed to be primarily on the Labrador-Island Link, with the island of Newfoundland consuming an increasing portion of the available power until only the 194 MW committed as maximum

capacity under the Base Block is available. The limitation is assumed to continue until 2042, when Newfoundland is expected to be looking for markets for power from the 5,500-MW Churchill Falls plant.

    - High: Nova Scotia can purchase up to 3.5 TWh/year of electricity over the Maritime Link – i.e., up to 500 MW at all times, minus the Base Block (and Supplemental Block in 2018-2022). Purchases are not limited by supply from Newfoundland, but the capacity of the Maritime Link. Nova Scotia is assumed to invest in whatever upgrades are necessary to allow it to absorb up to 500 MW landed at Cape Breton. The cost of these upgrades is not known at this time, but is unlikely to exceed $100 million, so a capital cost of $100 million is added in this scenario.
- Gas prices
    - Low U.S. gas price: Prices at the Dracut hub 20% below the base case
    - High U.S. gas price: Dracut prices 20% above the base case
    - Low Nova Scotia-U.S. differential: Burnertip prices in Nova Scotia are assumed to be below U.S. prices by an amount equivalent to transportation charges and losses between the U.S. border and the Dracut hub in Massachusetts, because Nova Scotia suppliers are charging Nova Scotia consumers what the suppliers would net from shipping their gas to New England for sale.
    - In the base case and high scenarios it is assumed that suppliers have reserved capacity on a take or pay basis and thus would need to recover cost of transportation whether used or not.
- Carbon allowance or CO_2 credit prices: these do not apply in Nova Scotia directly, but do apply in New England, where they have a direct impact on market prices, which affect the price of all imports except the Lower Churchill Base and Supplemental Blocks
    - Low: RGGI-only prices (around $2/tonne in 2012 dollars)
- Coal prices
    - Low: 20% below the base case, including all transportation charges
    - High 20% above the base case, including all transportation charges
- Demand
    - Low: 15% below the base case in all years
    - High: 15% above the base case in all years. It would be unreasonable to expect such a large increase in demand without a corresponding increase in supply. In the Lower Churchill scenario, therefore, it is assumed that Nova Scotia would invest in whatever system improvements were required to allow up to 500 MW of non-firm imports over the Maritime Link, as in the High Maritime Link Market Import case described above; the cost of these improvements, assumed to be $100 million, is included. The Hydro-Quebec contract scenario already includes 500 MW of import capability, and the Domestic Generation scenario assumes that enough wind and gas capacity will be built to meet demand.

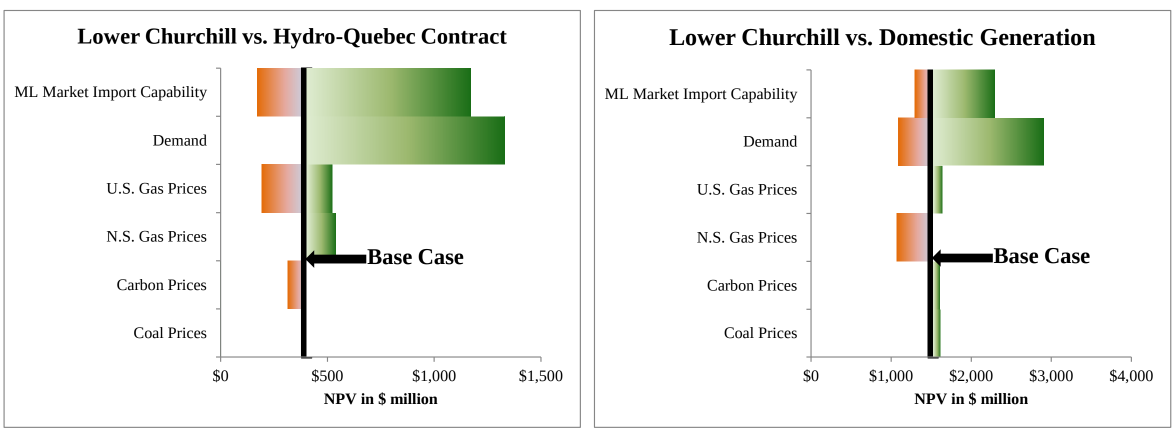
These sensitivity cases are intended to reflect a reasonable range of future market conditions while appropriately testing analysis results. For example, while the low gas price scenario is consistent with 2012 gas prices, these were the lowest prices seen in the last decade. It is unlikely that prices would remain at these low levels for the entire study period. The purpose of the sensitivity cases is to identify factors which could potentially affect the conclusions of this analysis. Results of the sensitivity tests – i.e., the difference between the three primary supply alternatives in net present value terms – are shown in Table 4 and Figure 1. Table 4 shows the results of each of the sensitivity cases in net present value terms, and Figure 1illustrates how these results vary from the base case. The Lower Churchill scenario was found to be the most cost-effective in all sensitivity cases.

Table 4: Sensitivity Case Results

(NPV in $ million)		LCP vs. Hydro-Quebec Contract		LCP vs. Domestic Generation	
Factor	**Range**	**Low**	**High**	**Low**	**High**
Base Case		**$402**		**$1,525**	
ML Market Import Capability	0.8* / 3.5 TWh/year	$172	$1,173	$1,300	$2,296
Demand	±15%**	$693	$1,329	$1,094	$2,907
U.S. Gas Prices	±20%	$192	$523	$1,528	$1,642
N.S. Gas Prices	Domestic Supply	$539	n/a	$1,074	n/a
Carbon Prices	RGGI only	$314	n/a	$1,609	n/a
Coal Prices	±20%	$402	$384	$1,503	$1,617

*In the Low ML Market Import Capability case, market import capability varies from 1.5 TWh/year in 2018 (300 MW, minus the Base Block and Supplemental Block) to 0.8 TWh/year in 2040 (194 MW, minus the Base Block), then increases to 1.7 TWh from 2042 on (300 MW, minus the Base block).
**In the High Demand case, ML Market Import Capability is increased to 3.5 TWh/year (500 MW, minus the Base Block; slightly less while the Supplemental Block is available).
Source: Power Advisory

Figure 1: Sensitivity Case Results



In comparing the Lower Churchill and Hydro-Quebec scenarios, the sensitivity cases with the greatest impact were the high market import capacity and high demand cases. Both cases assume that Nova Scotia would invest in whatever system improvements are required to allow up to 500 MW (rather than the base case assumption of 300 MW) to be imported over the Maritime Link at all times, and that such power would be available on a non-firm basis. The low Maritime Link

Import Capability case also has a significant impact. The range of value seen in these three sensitivity cases illustrates the importance of the Maritime Link in providing access to market-priced imports.

As well as sensitivity cases involving changes in the Maritime Link's import capabilities, the various gas price scenarios also had significant impacts, because they directly affect the price of imports and cost of domestic generation. The low carbon price case and the high and low coal price cases had less of an impact.

4.3 Meeting Nova Scotia's Strategic Policy Goals

Section 1.1 above outlines the Government of Nova Scotia's electricity sector strategic policy goals. These include:

- Promoting diversity of supply, in terms of location (geographically distributed across the province), energy source, ownership and contract term;
- Ensuring reliability: the government favours electricity transmission and supply options that offer another connection to electricity supplies and enhance the diversity of supply options. Recognizing the aggressive goal that it has set for renewable electricity, the government also seeks an appropriate balance between firm and intermittent renewable resources and, everything else remaining equal, favours those renewable resources that can be scheduled day-ahead and assist in balancing supply and demand on real time basis;
- Promoting a portfolio of flexible supply options to maintain regionally competitive electricity prices and manage customer costs. This includes access to short-term market-priced clean energy such as natural gas-fired generation and reducing exposure to international coal and oil prices by increasing reliance on local stably-priced electricity resources. This goal can be achieved by reducing dependence on any single energy source including coal, given Nova Scotia's significant reliance on it, and avoiding undue exposure to natural gas prices directly or indirectly, recognizing that imports even if not from natural gas-fired generation are often priced on the basis of natural gas prices; and
- Enabling achievement of GHG emission and other air pollutant obligations and renewable energy commitments in a balanced manner.

Table 5 compares the three primary supply alternatives relative to these strategic policy goals.

- Domestic generation would best satisfy the diversity of supply objective because it would result in the addition of numerous additional supply resources that would be dispersed throughout Nova Scotia. On the other hand, the Lower Churchill Project would just add one additional supply resource, but it would be a fairly large new supply resource that isn't currently available to Nova Scotia. Furthermore, it would create a new transmission path that provides direct access to one of the largest hydroelectric projects in North America (Churchill Falls) and another major hydroelectric project (Gull Island) that has received Environmental Assessment permitting and is seeking markets. A contract with Hydro-Quebec would add an additional competitive supply resource under contract and strengthen the interconnection with New Brunswick, but the transmission path and the generation resources that would utilize it already are available to Nova Scotia so they don't represent a significant increase to the diversity of supply in the same way as Lower Churchill. Therefore, the Hydro Quebec purchase promotes this objective the least.

- The reliability goal is focused on adding another connection to electricity supplies to support the diversity objective. The Lower Churchill Project best satisfies this goal. With only one relatively weak interconnection with another electricity system (New Brunswick), adding an additional interconnection to another electricity system would offer considerable diversity benefits. Such an additional interconnection would offer significant benefits in terms of the ability to respond to contingencies and this benefit would extend well beyond the study horizon. Both Lower Churchill and Hydro Quebec would offer greater scheduling capability than the additional domestic supply alternative. We assumed that Hydro-Quebec would be willing to provide the same scheduling flexibility as provided by Lower Churchill.

- Both Lower Churchill and Domestic Generation are likely to provide greater flexibility and offer greater price stability than a Hydro-Quebec purchase. Based on other recent long-term transactions (e.g., its sale to the Vermont utilities), Hydro-Quebec has sought a price that was indexed to ISO-NE market prices which are closely tied to natural gas pricing. Our analysis is based on an estimate of future market prices and models tend to understate wholesale market price volatility. Therefore, it is likely that we have understated the prices that Hydro-Quebec would receive under such a contract. This underscores the point that the Hydro-Quebec contract has inherently greater price uncertainty than the other alternatives. Therefore, a Hydro-Quebec contract doesn't perform as well as Lower Churchill. However, the Domestic Generation scenario is forecast to yield costs that are significantly higher than the other two alternatives under all sensitivities and the base case and as a result performed the worst.

- The Lower Churchill and Hydro-Quebec Contract scenarios perform equally well with respect to enabling achievement of GHG emission and other air pollutant obligations and renewable energy commitments, except that there is uncertainty about whether imports from Quebec would qualify as renewable energy under Nova Scotia regulations. For the Domestic Generation scenario, the model was not able to find solutions that met the greenhouse gas emissions cap in the later years of the study period.

Table 5: Ranking of Primary Supply Alternatives

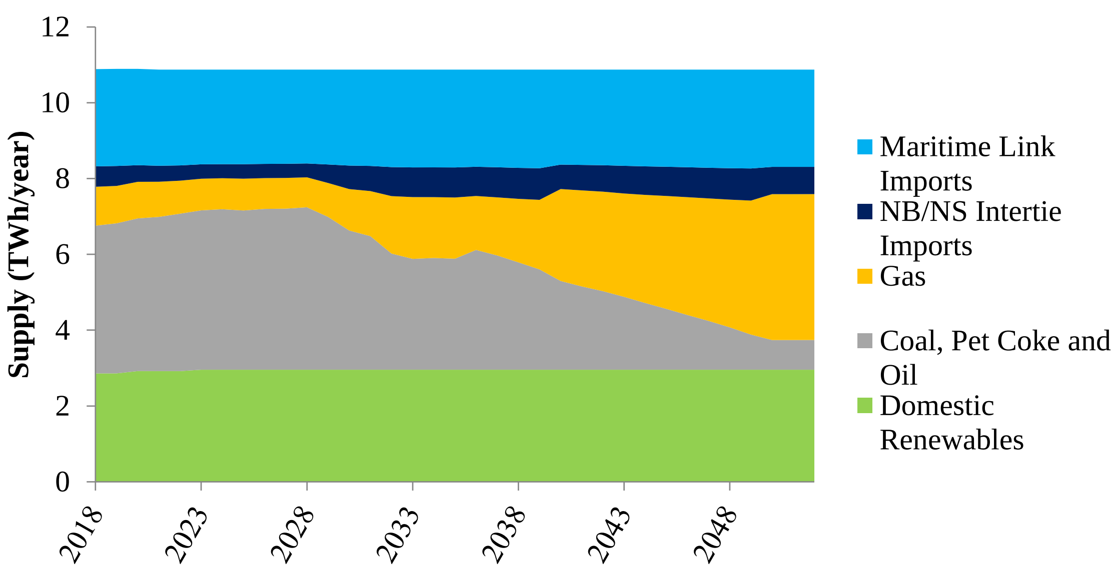
	Lower Churchill Project	Hydro Quebec Contract	Domestic Generation
Diversity of Supply	2	3	1
Reliability	1	2	3
Flexible Supply to Maintain Competitive Prices	1	2	3
Achievement of GHG emission and other air pollutant obligations and renewable energy commitments	1	1	3

Relative ranking: 1 – best meets criteria; 3 – least meets criteria

This comparison suggests that the Lower Churchill Project best satisfies these strategic policy goals.

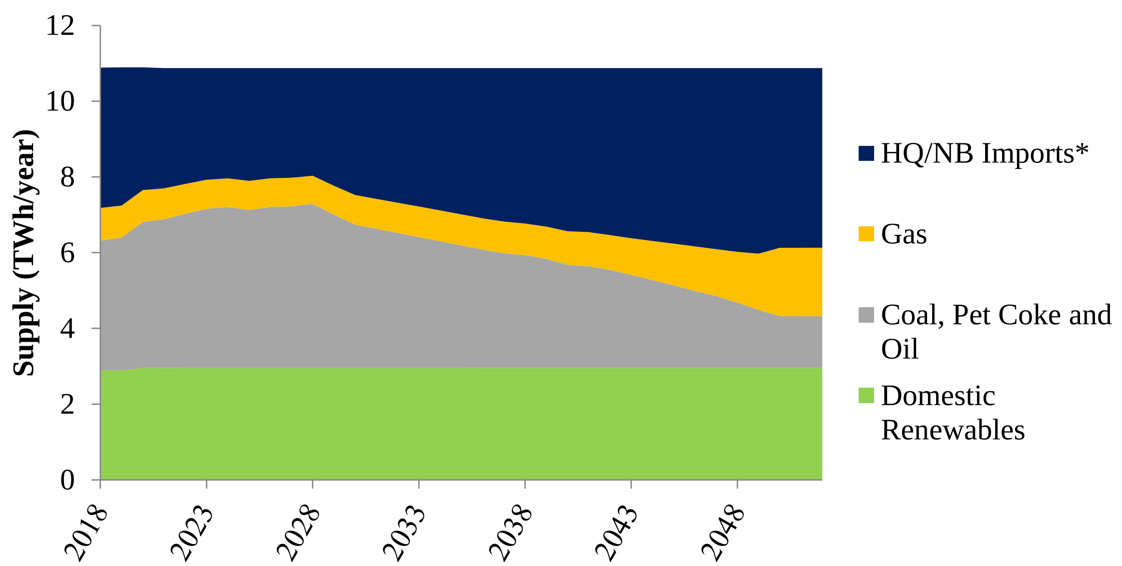
Appendix A: Modeling Results for the Optimal Supply Scenario with Lower Churchill

	2020	2025	2030	2035	2040	2045	2050
Electricity Supply (TWh)							
Coal, Pet Coke and Oil	4.03	4.20	3.67	2.93	2.34	1.61	0.78
Gas	0.96	0.84	1.09	1.62	2.43	2.98	3.85
Domestic Renewables	2.92	2.96	2.96	2.96	2.96	2.96	2.96
Maritime Link Imports	2.54	2.49	2.53	2.58	2.51	2.56	2.57
NB/NS Intertie Imports	0.44	0.38	0.62	0.79	0.64	0.77	0.72
Total	**10.89**	**10.87**	**10.87**	**10.87**	**10.87**	**10.87**	**10.87**
Emissions							
CO2e (million tonnes)	4.85	4.95	4.50	3.67	3.37	2.81	2.25
Sulphur (tonnes)	31,142	27,986	19,496	19,990	19,999	16,156	7,683
Mercury (tonnes)	35	35	30	30	27	19	9
NOx (tonnes)	8,508	8,705	8,088	8,091	7,164	6,754	5,958
Emissions vs. Caps							
CO2e Cap	-35%	-18%	0%	-7%	0%	0%	0%
Sulphur Cap	-14%	0%	-3%	0%	0%	-19%	-62%
Mercury Cap	0%	0%	0%	0%	-11%	-36%	-70%
NOx Cap	-43%	-21%	1%	1%	-10%	-16%	-26%



Appendix B: Modeling Results for the Optimal Supply Scenario with Hydro-Quebec Contract

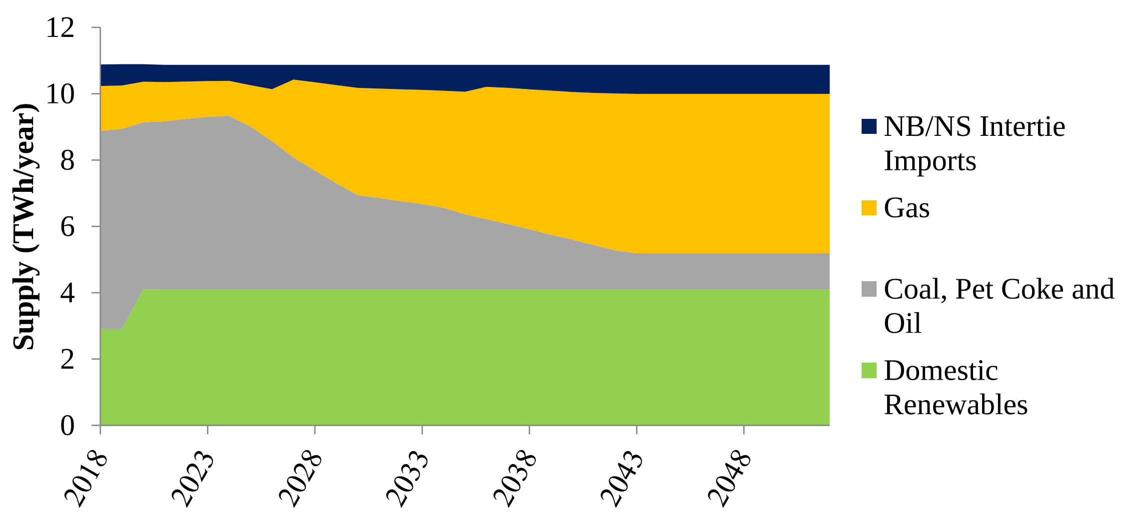
	2020	2025	2030	2035	2040	2045	2050
Electricity Supply (TWh)							
Coal, Pet Coke and Oil	3.85	4.17	3.78	3.24	2.72	2.18	1.36
Gas	0.84	0.77	0.79	0.82	0.89	1.10	1.81
Domestic Renewables	2.96	2.96	2.96	2.96	2.96	2.96	2.96
HQ/NB Imports*	3.24	2.98	3.35	3.86	4.31	4.64	4.74
Total	**10.89**	**10.87**	**10.87**	**10.87**	**10.87**	**10.87**	**10.87**
Emissions							
CO2e (million tonnes)	4.67	4.94	4.50	3.94	3.29	2.81	2.25
Sulphur (tonnes)	33,546	27,982	19,734	19,590	20,012	19,590	15,766
Mercury (tonnes)	35	35	30	30	30	29	19
NOx (tonnes)	8,628	9,258	8,475	7,366	6,478	5,856	4,934
Emissions vs. Caps							
CO2e Cap	-38%	-18%	0%	0%	-2%	0%	0%
Sulphur Cap	-7%	0%	-1%	-2%	0%	-2%	-21%
Mercury Cap	0%	0%	0%	0%	0%	-5%	-37%
NOx Cap	-42%	-16%	6%	-8%	-19%	-27%	-38%



*HQ/NB Imports includes imports over both the existing NB/NS intertie and the new 500-MW intertie. Imports are assumed to be sourced primarily from Hydro-Quebec.

Appendix C: Modeling Results for the Optimal Supply Scenario with Domestic Generation

	2020	2025	2030	2035	2040	2045	2050
Electricity Supply (TWh)							
Coal, Pet Coke and Oil	5.04	4.91	2.84	2.27	1.50	1.09	1.09
Gas	1.22	1.25	3.23	3.70	4.45	4.81	4.81
Domestic Renewables	4.10	4.10	4.10	4.10	4.10	4.10	4.10
NB/NS Intertie Imports	0.53	0.61	0.69	0.81	0.82	0.88	0.88
Total	**10.89**	**10.87**	**10.87**	**10.87**	**10.87**	**10.87**	**10.87**
Emissions							
CO2e (million tonnes)	6.16	6.01	4.50	3.93	3.37	3.12	3.12
Sulphur (tonnes)	36,245	27,548	19,500	19,021	17,077	12,729	12,729
Mercury (tonnes)	35	35	29	30	20	15	15
NOx (tonnes)	11,476	11,235	8,927	8,931	7,778	7,449	7,449
Emissions vs. Caps							
CO2e Cap	-18%	0%	0%	0%	0%	11%	38%
Sulphur Cap	0%	-2%	-2%	-5%	-15%	-36%	-36%
Mercury Cap	0%	0%	-3%	-1%	-32%	-49%	-49%
NOx Cap	-23%	2%	12%	12%	-3%	-7%	-7%



Appendix D: Abbreviations and Definitions

MMBtu (million British Thermal Units): A measure of the energy contained in a volume of natural gas.

MWh, GWh or TWh: These are all measures of electricity energy. One GWh (gigawatt-hour) is 1,000 MWh (megawatt-hour). One TWh is 1,000 GWh or 1,000,000 MWh.

MW (megawatt): This is a measure of electric power, or the rate of energy provided. It is often used to measure the maximum capacity that a plant or transmission line can provide.

Firm and Non-Firm Transmission Capacity: Firm transmission capacity is guaranteed at all times, and can be used in planning to serve peak demand. There are no guarantees on the availability of non-firm capacity and it may or may not be available when it is most needed (for example, during peak demand). Non-firm transmission capacity can be important in planning the supply of energy (electricity use over a full year) but not in planning capacity (electricity use at extreme times).