2013 **M05419**

NOVA SCOTIA UTILITY AND REVIEW BOARD

IN THE MATTER OF: ***The Maritime Link Act***, S.N.S. 2012, c.9 and the ***Maritime Link Cost Recovery Process Regulations***, N.S. Reg. 189/2012

- and -

IN THE MATTER OF: An application by NSP Maritime Link Incorporated for approval of the Maritime Link Project

DIRECT TESTIMONY OF JOHN DALTON
ON BEHALF OF THE NOVA SCOTIA DEPARTMENT OF ENERGY

APRIL 17, 2013

I. INTRODUCTION

Q. Mr. Dalton, please state your name, business address, and the nature of your business.

A. My name is John Dalton. I am President of Power Advisory LLC (Power Advisory). My business address is 706 West Street, Carlisle, Massachusetts. Power Advisory is a management consulting firm focusing on the electricity sector and specializing in electricity market analysis and strategy, power procurement, energy policy development, and electricity project feasibility assessment.

Power Advisory's clients include power planning and procurement agencies, regulatory agencies, generation project developers, and electric utilities.

Q. On whose behalf are you testifying in this proceeding?

A. I am appearing on behalf of the Nova Scotia Department of Energy (Department).

Q. What is your professional and academic background?

A. I am an electricity market analyst and policy advisor with over 25 years of experience in the electricity sector. I specialize in energy market analysis, electricity policy analysis and development, power procurement and contracting, generation project evaluation, and strategy development. I am experienced in the evaluation and analysis of electricity markets and the competitiveness and operation of various generation technologies and projects within these markets.

I have evaluated numerous electricity supply alternatives that have been proposed for the Atlantic Canada electricity markets by a wide range of market participants. This includes wind, natural gas, nuclear and hydroelectric projects. I have advised governments in Nova Scotia, New Brunswick and Newfoundland and Labrador on appropriate policies to promote the development of renewable energy in these markets, to enhance the competitiveness of these markets, and to conform to the open access transmission requirements of the US Federal Energy Regulatory Commission (FERC).

I have developed and overseen the development of numerous electricity market price forecasts across North America, including forecasts for the ISO-New England (ISO-NE) market, which is a critical reference pricing point for Atlantic Canada electricity markets. These price forecasts were used to support generation project development efforts, project financings, regulatory policies, and power procurement efforts.

I have reviewed numerous electric utility avoided cost estimates and advised clients on the reasonableness of these estimates and the methodologies for developing them. This includes costs avoided by renewable energy projects in the State of Vermont, avoided costs for the Ontario electricity market, and various avoided cost estimates developed by different New England electric utilities.

I have served as a consultant to the electricity sector for over 25 years with various firms and prior to this served as an economist with the Massachusetts Energy Facilities Siting Council where I reviewed electric utility demand forecasts and supply plans and applications for the construction of new energy facilities including the Phase II High Voltage Direct Current (HVDC) line that connects Hydro-Quebec with New England at Sandy Pond in Central Massachusetts. Prior to this, I served as an economist with the Massachusetts Department of Environmental Protection where I assisted with the costing of emission control initiatives that were targeted at electric utilities and major industrial facilities.

I have a BA in Economics from Brown University and an MBA from Boston University. I have taken courses in resource planning methods and regional planning at the Massachusetts Institute of Technology and Boston University. A copy of my curriculum vitae is attached as Exhibit PA-1.

Q. Please highlight experience relevant to your ability to provide expert testimony relating to the Maritime Link.

A. I have extensive experience evaluating electricity supply alternatives in the Atlantic Canada electricity markets and have performed assessments of major electricity projects in this region for over 15 years. This includes major hydroelectric projects in Newfoundland and Labrador, nuclear projects in New Brunswick, and wind projects in Nova Scotia, New Brunswick and Prince Edward Island. A critical aspect of the development of large electricity projects in this region is understanding the terms of access and the value of surplus energy in the New England market. I have evaluated these issues for over 15 years.

I also have extensive experience evaluating major new inter-jurisdictional transmission projects such as the Maritime Link. These projects include (1) the International Power Line, a 345-kV AC line between New Brunswick and New England, for the Government of New Brunswick; (2) the Western Grid, a proposed HVDC line that would interconnect Manitoba, Saskatchewan and Alberta for a consortium that included the Governments of these three Provinces, TransCanada, the crown utilities in Manitoba and Saskatchewan, and the Alberta Electric System Operator; and (3) an HVDC interconnection between Quebec and Ontario proposed by Hydro One and Hydro-Quebec. In addition, I assisted the Ontario Energy Board evaluate the economic analysis proposed by Hydro One for a series of 230 kV transmission lines that would address the Queenston Flow West constraint. The scope of services provided included performing studies to determine the economic value of the proposed transmission facilities, evaluating the studies performed by third-parties for electricity regulators such as the Utility and Review Board (UARB or Board), and assessing the numerous economic and market barriers to the development of such facilities.

Q. Highlight your experience in Canada, and in Nova Scotia.

A. I have evaluated Canadian electricity markets and advised major market participants in these markets for over 15 years. From 1999 to 2005, I lived in Toronto and focused exclusively on Canadian electricity markets. During this time I assisted

Governments in New Brunswick and Nova Scotia with the development of energy policies and strategies and the reform of their electricity systems.

With respect to Nova Scotia I have assisted electricity project developers understand opportunities offered and challenges posed by its electricity market. In July 2011, Power Advisory was appointed by the Government to serve as the Renewable Electricity Administrator (REA) and develop a request for proposals for at least 300 GWh of renewable energy from Independent Power Producers. I managed Power Advisory's REA team.

Q. Have you testified before a tribunal or court to provide expert evidence?

A. Yes. I have testified in about twenty proceedings across North America and was qualified to speak as an expert in those proceedings on issues ranging from the need for and comparative economics of new electric generating facilities, standard-offer programs for the procurement of renewable energy and capacity, electric utilities' competitive procurement programs, wholesale electricity market prices, transmission pricing policy, and the likely competitiveness of wholesale power markets.

Q. Have you appeared before the UARB?

A. No. I have not formally testified before the Board. However, when serving as the REA, Power Advisory was required to have the power purchase agreement that we developed with the input of stakeholders approved by the Board. In a paper hearing before the Board, I oversaw the development of our initial filing, response to comments filed by stakeholders, and compliance filing that addressed the Board's decision.

II. PURPOSE OF TESTIMONY

Q. What is the purpose of your testimony?

A. Power Advisory was engaged by the Department to assess the economic merits of the Maritime Link and the associated delivery of renewable energy from the Muskrat Falls Hydroelectric (Muskrat Falls) Project under the formal agreements negotiated between Emera Inc. (Emera) and Nalcor Energy (Nalcor) relative to other alternatives, and to assist the Department with its anticipated participation in this UARB hearing regarding the Maritime Link. This testimony presents the findings from this analysis and provides Power Advisory's assessment of the Muskrat Falls project.

III. SUMMARY OF ASSESSMENT OF MARITIME LINK

Q. Have you summarized your assessment of the Maritime Link Project?

A. Yes. My findings are presented in a report titled "Analysis of Proposed Development of the Maritime Link and Associated Energy from Muskrat Falls Relative to Alternatives", dated January 16, 2013 (Report) and an Addendum that evaluated the comparative economics of a low renewables, more natural gas alternative.

Q. Have you undertaken any further assessments of the Maritime Link Project since the filing of these Reports?

A. Yes. On January 28, 2013, Nova Scotia Power Maritime Link (NSPML) filed its Application with the Board for the approval of the Maritime Link Project. In reviewing this Application and the information request responses filed by NSPML, I have refined some of the assumptions in my analysis and updated the results of the analysis. However, there are no substantive changes to my finding that the Maritime Link and associated energy from Muskrat Falls represents the lowest cost alternative available to Nova Scotia customers for addressing the environmental requirements and electricity policy goals adopted by the federal and provincial governments.

An updated copy of this Report is attached as Exhibit PA-2.

Q. Please summarize the analysis that you undertook to prepare the Report.

A. The starting point for the analysis was to accurately represent the Nova Scotia electricity supply system and Nova Scotia customer's electricity demands. As part of this analysis we also reflected Nova Scotia's electricity interconnections and the pricing likely to be available from generation resources available in these interconnected markets. The key assumptions are outlined in Exhibit PA-2.

The model focused on differences in supply costs, rather than total costs, relative to the base case, which assumes that the Maritime Link is built and that Nova Scotia receives the Base and Supplemental Blocks and has access to surplus energy. 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 would be provided by Muskrat Falls, but based on market prices.
- Additional domestic wind and natural gas generation in Nova Scotia, including enough wind (or other domestic renewable energy) to meet federal and provincial emissions and the province's 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 analysis compares the options and identifies the lowest cost option.

Q. What are the major assumptions that have changed from your January 16th Report to the version filed with this Testimony?

A. I have updated the analysis to reflect revised assumptions for transmission losses; the escalation rate for transmission charges; coal unit retirements in Nova Scotia; New England natural gas and energy prices; the cost of carbon dioxide emission allowances in New England under the Regional Greenhouse Gas Initiative; the capacity obligation provided by Hydro-Quebec; and the depreciation period for the transmission investments required by a Hydro-Quebec contract.

Q. Please summarize your analysis results.

A. The table below summarizes the results of Power Advisory's comparison of the value of the Maritime Link relative to the two primary alternatives that we compared it to. On a net present value basis the Maritime Link scenario is projected to be $342 million less expensive (in 2017 dollars) than the Hydro-Quebec Contract scenario, and $1.480 billion less expensive than the Domestic Generation scenario, over the 35-year term of the Lower Churchill Project contract (2017-2052). When the post-contract value is considered assuming an additional 35 years of post-contract operation, these differences increase to $412 million and $2.243 billion respectively. These net present value calculations are based on a discount rate of 6%.

($ million, in 2017 $)	Net Present Value Contract Period (2017-2052)	 Including Post-Contract Value
Hydro-Quebec Contract vs. Maritime Link	$342	$412
Domestic Generation vs. Maritime Link	$1,480	$2,243

Q. How did you ascertain the terms under which Hydro-Quebec might be willing to sell power to Nova Scotia?

A. I used information regarding terms that Hydro-Quebec had negotiated with other parties to determine the conditions that it would likely seek for a deal with Nova Scotia. The analysis is based on the revenues that Hydro-Quebec would be able to realize from one of its many different export market delivery points, i.e., the Mass Hub in the ISO-New England market. For example, Hydro-Quebec has two interconnections with New Brunswick which is also directly interconnected with New England, two primary interconnections with New England, one interconnection with New York and numerous interconnections with Ontario. The New England and New York electricity markets have locational marginal pricing whereby prices at different nodes (interconnection points) on the transmission network can differ when there is transmission congestion or different marginal losses. Therefore, each of these interconnection points with New England and New York and the interconnections with New Brunswick and Ontario can offer a different price depending on market conditions. Market price differences provide Hydro-Quebec with the opportunity to pick the interconnections which offer the highest net-back price. By assuming that Hydro-Quebec would base its sales price on the market price at one interconnection point, we have understated the net-back price that Hydro-Quebec could realistically expect to receive and would be likely to demand in negotiations.

In addition, we assumed that it would make energy available during all peak hours seven days a week when in fact, given that there are limits on the amount of energy that it can deliver to export markets, given the significant amount of interconnection capability with these other markets Hydro-Quebec is more likely to be interested in concentrating deliveries during hours that offer higher prices.

Q. How does your Report compare to the analysis of alternatives to the Maritime Link project undertaken by NSPML in its application?

A. While there are differences in assumptions between the two analyses, these are generally relatively minor differences. More importantly, the two analyses support the same finding: that the Maritime Link Project is the lowest cost alternative available to Nova Scotia customers for achieving the environmental requirements and electricity policy objectives adopted by the federal and provincial governments. The fact that two separate analyses that evaluated a wide range of potential market conditions indicate that the Maritime Link Project is the lowest cost alternative demonstrates that the project performs well under a wide range of conditions and therefore, the economics of the project are robust. This is significant given the uncertainty associated with future market conditions.

Q. Do you believe that the alternatives that you considered were too narrow and that a wider range should have been considered?

A. No. Nova Scotia will be required to meet the terms of the draft Equivalency Agreement negotiated with the Federal Government which imposes increasingly stringent carbon caps on Nova Scotia Power's (NS Power's) generation fleet. In addition, through a series of regulations the Nova Scotia Government has imposed sulfur dioxide (SO_2), oxides of nitrogen (NO_x), and mercury emission reductions on NS Power. In addition, under the Renewable Electricity regulations 40% of Nova Scotia's total energy requirements are required to be provided by qualifying renewable energy resources. Therefore, any alternative that is considered needs to meet these requirements and there are a limited number of alternatives available that can satisfy these requirements. The two alternatives that we considered are the most viable.

Q. Did the analysis disadvantage the Hydro-Quebec alternative by overstating the appropriate size of the interconnection?

A. No, it did not. By way of background, we assumed that Nova Scotia's interconnection with New Brunswick and New Brunswick's interconnection with Quebec would be reinforced to allow 500 MW of additional energy to be transmitted across these interfaces while we have assumed a firm purchase of only 165 MW, with 154 MW ultimately delivered to Nova Scotia.

We evaluated a 300 MW connection with New Brunswick, and confirmed that a smaller connection offers less value than a 500 MW connection. The larger connection represents a wider pathway for additional energy or capacity when market conditions or reliability requirements warrant the delivery of additional energy or capacity. If there were only 300 MW of additional interconnection capacity with New Brunswick, and Quebec with New Brunswick, the Hydro-Quebec alternative would cost $561million more than the Maritime Link alternative over the 35-year contract period. And this analysis conservatively assumed that there were no foregone economies of scale associated with developing a 300 MW interconnection relative to a 500 MW interconnection, i.e., that the cost of a 300 MW interconnection would be proportionally less than a 500 MW interconnection. The larger connection offers greater value given the greater availability of competitively priced market energy. Therefore, the assumption that the Hydro-Quebec alternative would provide the same transfer capability as offered by the Maritime Link by no means disadvantaged the Hydro-Quebec alternative.

Furthermore, when comparing alternatives it is helpful to ensure to the degree possible that the two alternatives are directly comparable and have similar attributes, e.g., offer the same increase in interconnection capacity. With the Maritime Link having a transfer capability of 500 MW, it is appropriate to consider a 500 MW new connection with New Brunswick for the delivery of energy from Quebec.

Q. Are there other scenarios that you considered?

A. Yes. We considered the possibility that Hydro-Quebec would provide a balancing service similar to that offered by natural gas-fired generation for Nova Scotia's incremental wind generation. This alternative would provide Nova Scotia with a call on energy deliveries from Hydro-Quebec when needed to meet Nova Scotia's energy requirements up to the 154 MW of energy delivered net of losses offered by the Base Block. In essence, Hydro-Quebec would have to reserve 154 MW of generating and transmission capacity for Nova Scotia to meet its firm requirements. However, there would be no corresponding commitment to take energy. Assuming the same total incremental energy requirement, the total amount of energy that would be needed from Hydro-Quebec would be reduced by the incremental amount of wind energy delivered.

Therefore, the cost of transmission upgrades would be amortized over fewer MWh increasing the effective unit cost of the transmission upgrades. Furthermore, Nova Scotia would need to pay a premium to Hydro-Quebec for this service to reflect the opportunity cost associated with having a reservation on this generation and transmission capacity since whenever Nova Scotia calls on this capacity, Hydro-Quebec would be unable to use it to participate in other markets. Therefore, we estimate that this alternative would be more costly than the Hydro-Quebec alternative analyzed in the Report.

Q. Did you evaluate a low renewables, more natural gas alternative where the 40% renewable energy requirement is relaxed?

A. Yes, I evaluated a scenario where the 25% requirement that is covered by renewable resources that are already built or under contract is maintained. The analysis indicated that a less renewables, more natural gas alternative is cheaper than the Domestic Generation alternative which includes wind and natural gas, but is about $1.8 billion more expensive than the Maritime Link when post-contract value is considered. Furthermore, this alternative subjects Nova Scotia customers to greater natural gas and carbon price risks given the volatility of natural gas prices and uncertainty regarding future carbon prices.

Q. Do you have any comments regarding the strategic value of the Maritime Link relative to alternatives?

A. Yes. I believe that there are a number of significant strategic advantages associated with the Maritime Link that distinguish it from the two primary alternatives that I evaluated. First of all, with the development of the Maritime Link, Nova Scotia would no longer be at the end of the North American electric transmission grid. It would be part of an integrated transmission path which runs through Newfoundland and Labrador on to Quebec and New England. Equally important, it represents an interconnection to an area with up to 45 TWh of hydroelectric energy that would be available from Muskrat Falls, Churchill Falls and potentially Gull Island. Directly adjacent to Newfoundland and allowing suppliers to avoid transmission charges in New Brunswick and Nova Scotia, Nova Scotia would be well positioned to purchase this energy, which absent the Maritime Link wouldn't be available to Nova Scotia under the same favourable terms. Furthermore, given short contracting terms in New England and the likely desire of suppliers to maintain a diversity of contract terms, there is likely to be significant amounts of surplus energy available to purchase as a result of the development of the Maritime Link beyond the 35-year contract term. Therefore, the Maritime Link represents a dramatic enhancement in the supply diversity and competitive supply alternatives available to Nova Scotia.

Q. Are there other sources of strategic value that should be considered?

A. Yes. As the analysis shows, the Maritime Link represents a robust strategic supply alternative that performs well under a wide range of market conditions. The Maritime Link provides access to both a block of fixed price energy with favourable operating characteristics given NS Power's dispatchability rights and market-priced energy with no associated emissions. With high market prices the fixed price block of energy is more valuable and under low market prices the market-priced energy is attractive. In addition, the better access to market-priced energy enhances Nova Scotia's ability to respond to unanticipated events including extended generator outages, more stringent environmental requirements, and significant changes in load. This is a significant enhancement to the diversity of supply options available to Nova Scotia.

Q. Do you have any additional comments regarding the strategic value of the Maritime Link?

A. Yes. While the Maritime Link shows broad-based economic benefits when compared to viable alternatives, even if it were to offer an equivalent cost we believe that Nova Scotia would be well served by pursuing the Maritime Link given the significant benefits offered beyond the Base Block term and overall strategic value.

Q. Does this conclude your direct testimony?

A. Yes.

John Dalton

John Dalton
President

Power Advisory LLC
706 West Street
Carlisle, MA 01741
Cell: 978-831-3368
Tel: 978-369-2465

jdalton@poweradvisoryllc.com

Professional History

- Navigant Consulting
- Reed Consulting Group
- R.J. Rudden Associates Inc., 1987-1988
- Massachusetts Energy Facilities Siting Council, 1984-1987
- Massachusetts Department of Environmental Protection, 1981-1984

Education

- Boston University, MBA, 1987
- Brown University, BA, Economics, 1980

A senior electricity market analyst and electricity policy consultant with over twenty five-years of experience in energy market analysis, power procurement, project valuation, and strategy development. Experienced in the evaluation and analysis of electricity markets and the competitive position of generation technologies and projects within these markets including the assessment of the competitiveness of the underlying market, the development of power market price forecasts, the implementation of power procurement processes, and the development and evaluation of renewable energy policies. Frequent speaker on these subjects at energy industry conferences.

Professional Experience

Market Assessment

» Developed and supported numerous market price forecasts for wholesale power markets across North America. Price forecasts were used to support generation project development efforts, project financings and acquisitions, regulatory policy development, and power procurement efforts.

» Demonstrated the need for electric generation projects in filings submitted to various state and provincial regulatory agencies. Evaluated the cost of a wide range of different generation technologies for a number of clients. Defended analyses in prepared and oral testimony before these state agencies.

» Conducted wholesale power market analyses across North America for a wide range of market participants. Analysis included identifying likely competitors and pricing, security provisions, and general terms and conditions of various power supply options. Evaluated pricing required to compete in the market.

» Advised the Ontario Electricity Financial Corporation with the management of its non-utility generation contracts. Advice included addressing the policy issues associated with balancing concerns with the sanctity of existing contracts and the desire to minimize stranded debt as well as to use the contracts as a source of competitive discipline for the incumbent provincial electric utility.

» Managed a team that was retained by a large power generation company to develop a market assessment and wholesale power market price forecast for the Alberta market. Our assessment focused on issues affecting the fundamentals of the Alberta power market, including the future demand supply balance, growth in demand, market interconnections, and potential new generation capacity additions.

» Retained by the financial advisors for the developer of a proposed new combined cycle gas turbine project in Alberta to establish the toll between the Corporate entity participating in the income fund and the parent. Defended forecast assumptions and the modelling approach before investors as part of a public offering.

» Directed the use of ProSym in a proceeding before the Alberta Energy and Utilities Board (AEUB) to estimate the costs of transmission congestion and the benefits of increasing the transfer capability of the North South transmission interface. Modeling assumptions and methodology were successfully defended before the AEUB.

» Advised numerous generation project developers across North America on opportunities offered by participating in the relevant wholesale power market and various power supply procurement RFPs. Evaluated market risks and outlined strategies for managing these risks most efficiently.

» Analyzed and critiqued the supply planning methodologies of electric and gas utilities, focusing on the appropriateness of the supply planning models and methods. Provided recommendations for improving supply planning methods which were designed to assist the utilities in addressing the uncertainties associated with long-range planning. Prepared recommendations for the refinement of demand forecasting methods for electric and natural gas utilities. Analyzed and evaluated the statistical and quantitative projection methods used, including end-use and econometric forecasting techniques.

» Evaluated electric generating technologies on the basis of the capital and operating costs, technological risk, and environmental impact, identifying a preferred alternative in light of these considerations. Defended the selection process before a regulatory agency.

» Prepared strategic plan for a number of electric and natural gas market participants which evaluated the state/provincial and federal regulatory climate for cogeneration and generation projects, market prices and risks and recommended a competitive strategy.

Market Structure Development and Evaluation

» Advised the governments of Ontario, New Brunswick, Nova Scotia, Western Australia, and Manitoba regarding the restructuring of their wholesale power markets and possible market structures to achieve a workably competitive wholesale market.

» Responsible officer for market design project for the Province of New Brunswick. Navigant Consulting assisted the Market Design Committee and its subcommittees in providing the Minister of Natural Resources and Energy with recommendations on the implementation of electricity restructuring. Issues addressed included developing a market design that addresses concerns with the potential for the exercise of market power and enables New Brunswick to integrate with its interconnected markets. The Market Design Committee addressed development of the electricity market including its design, structure and rules. Navigant Consulting provided advice on the issues to be addressed, prepared issue papers and presentations, created strawmen for resolution of issues, and developed guidelines and direction for the creation of market design rules and protocols.

» Project manager for an assignment with the Province of New Brunswick to assist with the development of its ten-year energy policy. The cornerstone of this energy policy was the framework for restructuring its wholesale and retail electric markets. Advised regarding developments in other wholesale and retail markets and the prospects for meaningful competition in New Brunswick's wholesale and retail markets. Navigant Consulting advised regarding benefits offered by wholesale and retail competition; strategies for protecting New Brunswick consumers from market dislocations and higher prices; appropriate regulatory frameworks for the wires businesses and the prospects for achieving a workably competitive wholesale market in New Brunswick and the resulting market design requirements; and policies for addressing stranded costs raised by market restructuring.

» Markets and economics expert for a project with Western Power, the state-owned fully integrated utility that serves the vast majority of Western Australia. Advised regarding potential changes to the wholesale and retail electric power markets to enhance the competitiveness of these markets. Alternative market structures were evaluated and assessed in an effort to determine the market structure that offers the greatest societal net benefits. Offered proposed market structure changes that would accommodate government policy objectives of allowing greater levels of retail contestability and new entrants to satisfy the market's need for additional capacity. Evaluated restructuring reforms that had been implemented in a range of different markets that were of a similar size as Western Australia.

» Advised the Energy Strategy Working Group regarding the development of an electricity restructuring policy for the Province of Nova Scotia. Reviewed the experience with respect to the wholesale and retail market restructuring in California, New England, PJM, and Alberta and based on this experience outlined lessons learned and potential implications for electric restructuring Nova Scotia. Outlined the arguments for considering the restructuring of Nova Scotia's electricity market, reviewed contrasting market models, and discussed the critical constraints on wholesale and retail market restructuring in Nova Scotia.

» .Provided numerous presentations regarding the experiences with the restructuring of wholesale power markets and the lessons learned. Markets evaluated have included California, Alberta, New York, New England, PJM, Victoria, and England and Wales.

Project Valuation

» Served as Project Manager for assignments requiring the development of valuation estimates for numerous energy projects. Projects typically entailed modeling revenues and costs to predict cash flows and calculate the cumulative present worth of after-tax cash flows. The overall viability of projects were assessed by reviewing the status of project permitting efforts and financial commitments, the major provisions of power purchase agreements and steam purchase agreements.

» Managed a project to provide an independent valuation of a multi-unit generating portfolio as part of a refinancing for the portfolio. Oversaw and managed the development of an electricity market price forecast and estimate of the fair market value of the proposed portfolio. Defended analyses before credit rating agencies and lenders.

» Completed a comprehensive valuation of an oil-sands cogeneration project. As part of this effort, the team examined various market scenarios and potential spot market volatility and the subsequent impact on the client's electricity commodity costs.

» Performed detailed analyses of numerous generation projects' financial feasibility. Analyses considered alternative financing schemes and identified strategies for enhancing project values.

» Evaluated the economic and financial feasibility of a number of different generation projects for project developers, project hosts, and a gas utility. Assisted in the development of a cogeneration feasibility assessment model.

- Developed an estimate of the capital and operating costs of a wide range of generating technologies as part of a comprehensive assessment of the costs of new entry. Also estimated the appropriate cost of equity using the capital asset pricing model and debt and capital structure based on market information for merchant generators.

- Oversaw the development of numerous electricity distribution company valuation models. Used models to derive an estimate of the fair market value of the LDCs. Defended analysis before utility boards and management.

- Developed quantitative and qualitative analyses of generating assets in support of numerous generation asset acquisitions. Assisted in the management and coordination of multiple facets of the due diligence process, including technical engineering assessments, environmental, fuel supply, etc. Experience includes a broad range of fuels / technologies, including wind and other renewables.

Power Procurement Support

- Advised on the development of over 20 RFPs for power supplies and demand-side resources for electric utilities across North America, serving as project manager for well over half of these RFPs. Support covered the full range of RFP support services including advising regarding the appropriate form of the RFP and evaluation process to secure resources that best satisfy the client's objectives, drafting the RFP, developing the evaluation framework, marketing the RFP process to prospective bidders and negotiating with bidders.

- Advised on commercial issues for power purchase agreements.

- Offered testimony before the Massachusetts Department of Public Utilities on a utility RFP process. Authored reports on the evaluation of proposals.

- Managed numerous competitive solicitations for renewable energy resources and energy efficiency projects. Projects involved the development of frameworks for evaluating these energy alternatives and for comparing them on a consistent basis with conventional electricity supplies. Analyses considered the relative environmental impacts, reliability benefits, and cost-effectiveness of alternatives.

- Acted as Project Manager for several assignments to serve as the independent evaluator of conventional generation, renewable resource and demand-side RFPs. Responsible for determining whether proposals satisfy the threshold requirements in the RFP and for scoring all proposals. Also responsible for identifying the short-list of proposals, conducting bid clarification meetings with shortlisted bidders, and recommending to the selection of winning bidders.

Transmission Facility Review and Pricing Proceeding Support

- Advised the staff of the Ontario Energy Board on the evaluation of the proposal for a 1,250 MW HVDC line between Quebec and Ontario and served as a participating staff member for the Massachusetts Energy Facilities Siting Board's evaluation of the 2,000 MW HVDC interconnection between Massachusetts and Quebec.

- Advised OEB staff on the review of evidence presented by Hydro One in its application for two 240 kV transmission lines to alleviate the Queenston Flow West constraint.

- Advised clients in Saskatchewan, Newfoundland and Labrador, and Alberta on transmission pricing issues. Testified in the Alberta Transmission Congestion Pricing Principles proceeding.

- Led a consulting team that assisted with the preparation of the East-West Electrical Transmission Grid Study. Authored subsequent updates to this study for Natural Resources Canada.

» Advised a client regarding the elements of a comprehensive electricity export policy framework. Advice focussed on economic and social issues arising from the development of export oriented transmission infrastructure to support the development generation for export.

» Provided testimony on Northeast power markets and transmission issues and consequential damages in a civil case in New York. Evaluated the implications of the loss of a transmission facilities on the power system adequacy.

» Advised a number of clients on the issues associated with the development of merchant transmission facilities. Projects included reviewing the status of merchant project development efforts, merchant project structures, key success factors for merchant plant development and a review of merchant plant development opportunities worldwide.

Renewable Energy Policy Development and Evaluation

» Advised governments of Ontario, New Brunswick, Nova Scotia, and Manitoba on policies for the promotion of renewable energy technologies.

» Advised the Ontario Select Committee on Alternative Fuels on the most promising renewable technologies, identified barriers to their development and adoption and proposed policies for overcoming these barriers.

» Directed a project for a group of municipalities in Manitoba that evaluated the economic opportunity offered by wind projects in Manitoba and identified policies to promote the development of Manitoba's wind resources.

» Advised the Ontario Power Authority on the development of a standard offer for renewable energy technologies.

» Delivered a presentation on Canadian policies to promote the development of wind energy projects. Presentation reviewed federal and all relevant provincial programs and policies to promote the development of wind energy projects.

» Developed recommendations for the Manitoba Sustainable Energy Association on policies to promote the adoption of renewable energy technologies in Manitoba. Reviewed the relative advantages and disadvantages of standard offers versus RFPs and made recommendations regarding the appropriate applications of each.

» Advised numerous electricity generation development companies on the implications and opportunities presented by renewable energy policies. Developed strategic plans for a wide range of renewable energy technologies including large scale wind, landfill gas, biomass, anaerobic digestion, and small hydro.

» Evaluated electricity wholesale market and REC prices that would apply to landfill gas projects and reviewed US federal policies that benefited these projects including the production tax credit.

» Reviewed the general market for the development of renewable energy projects in Canada and contrasted market conditions with those in other countries.

» Led the development of a multi-client study that evaluated the opportunities for wind project development in Ontario under existing federal and provincial programs.

» Contrasted state RPS programs by identifying eligible technologies, eligibility requirements for projects in different jurisdictions, strategies for assessing compliance, RPS targets, and penalty provisions for failure to achieve the target.

Speaking Engagements

» "Strategies for Enhancing the Value of Your Asset", IBC Conference, (November, 1999)

» "Electricity Restructuring Lessons Learned: Implications for Ontario", Ontario Energy Marketers Association (April, 2001)

» "Electricity Power Prices in the Deregulated Ontario Market, 2001 CERI Conference, (October, 2001)

» "Electricity Restructuring in the US and Eastern Canada", World Bank/CREG/CERI Conference, (November, 2001)

» "Prices and Price Volatility in the Ontario Wholesale Power Market" PowerFair 2002, (May, 2002)

» "Pricing Fundamentals in the Ontario Wholesale Power Market" PowerFair 2003, (August, 2003)

» "The Economics of Power Generation in Atlantic Canada", 2003 Atlantic Power Summit (October, 2003)

» "Future Opportunities in the Maritimes", 2003 Ontario Energy Contracts Conference, (November, 2003)

» "A Perspective on Ontario's Evolving Wholesale and Retail Power Market Structures", PowerFair 2004, (May, 2004)

» "Canadian Policies to Promote Wind Project Development" EUCI's 4th Wind Energy and Power Markets Conference (September, 2004)

» "Effectively Navigating Ontario's RFP Processes" Power ON Conference, (October, 2004)

» "Enhancing the Performance of the Maritimes Market", 2004 Atlantic Power Summit, (November, 2004)

» "What Will the Ontario Landscape Look Like?", 2005 Ontario Energy Contracts Conference, (January, 2005)

» "Policies to Promote the Adoption of Renewable Energy Technologies in Manitoba", Manitoba Sustainable Energy Association, (April, 2005)

» "Outlook for Ontario Electricity Supply & Pricing", PowerFair 2005, (May, 2005)

» "Key Risks Affecting Ontario Electricity Consumers", AMPCO General Member Seminar (November, 2005)

» "What Kind of Market Structure Would Spark New Investment?" Canadian Institute's Generation Adequacy in Ontario Conference (April 19, 2006)

» "Where are Electricity Pricing Going" Insight Information, Ontario Power Forum (June 15, 2006)

» "Transmission Planning and Policy Development: An Update", APPrO Conference (November 15, 2006)

» "Recent Developments in Transmission Access and Pricing" Insight Information's Grid Reliability and Competition in the Power Sector (December 12, 2006)

» "Renewables in Ontario" Insight Info Conference (June 14, 2007)

- "Report Card on Ontario's Electricity Market" Ontario Energy Association Annual Conference (September 6, 2007)

- "Opportunities for Selling Renewable Power into the New England Market" Insight Info's 5th Annual Atlantic Power Summit (September 26, 2007)

- "New England Market Opportunities and the Prospects for Increased Inter-Regional Trade" Canadian Institute's Atlantic Energy Conference (May 28, 2008)

- "Cost Recovery and Return on Equity for Transmission Investment in the U.S.", Canadian Electricity Association Transmission Council (February 25, 2009)

- "Ontario's Feed In Tariff in the Context of North American Renewable Energy Policies", 2009 OEA Industry Leaders' Roundtable (April 30, 2009)

- "Transmission as Barrier to Wind Power Exports from the Maritime Provinces to the US Northeast", Canadian Wind Energy Association Wind Matters Conference (May 20, 2009)

- "Electricity Transmission Enhancements to Capitalize on Opportunities for Renewable Resource Development", Renewable Energy Conference 2009 (May 28, 2009)

- "Lessons Learned in the Design of Standard Offer and Feed-in Tariff Programs" Vermont Public Service Board Standard Offer Workshop (July 10, 2009)

- "Impact of the Current Economic Climate on North American Renewable Energy Investment", Rothesay Energy Dialogue 2009 (July 14, 2009)

- "Evaluation of Opportunities and Barriers to Wind Power Exports from the Maritime Provinces to the US Northeast", CanWEA 2009: Infinite Possibilities (September 21, 2009)

- "Stakeholder Conference Presentation on the Cost of Capital", Ontario Energy Board (September 22, 2009)

- "Opportunities Offered by the New England Power Market", Insight Info's 7th Annual Atlantic Canada Power Summit (October 5, 2009)

- "Assessment of Ontario's Green Energy Act and its Implications for Ontario", PowerLogic ION Users Conference 2009 (October 23, 2009)

- "Securing Regulatory Support for Smart Grid Investments", Canadian Electricity Association Customer Council (November 24, 2009)

- "Creating a Policy Environment that Supports New Transmission Development", Canadian Institute's Transmission and Integrating New Power into the Grid, (April 19, 2010)

- "Policies for Facilitating Transmission Investment" 2010 OEA Energy Leader's Roundtable, (April 21, 2010)

- Clean Energy Dialogue Conference, U.S. Department of Energy and Natural Resources Canada, (May 20, 2010)

- "Providing Revenue Stability for Offshore Wind: PPAs, RFPs and FITs", Insight Info's Freshwater Wind 2010 (July 19, 2010)

- "Market and Economic Barriers to Electricity Storage", Canadian Electricity Association Generation Council Meeting,, (September 16, 2010)

- "Opportunities Offered by the New England Power Market", Canadian Wind Energy Association: Growing Wind Energy in Atlantic Canada, (September 22, 2010)

- "Considerations for Implementing Feed in Tariffs in Atlantic Canada", 8th Annual Atlantic Canada and US NE Power Summit (October 26, 2010)

- "The Role of Cross Border Trade in Achieving Regional Renewable Energy Objectives", Council of State Governments Energy Plenary (August 8, 2011)

- "Overview of RFP Process for the Procurement of 300 GWh of Renewable Energy from IPPs", The Nova Scotia Feed In Tariff Forum (September 22, 2011)

- Procuring Renewable Electricity under Long-Term Contracts: Balancing Customer and Developer Interests, Atlantic Canada and NE US Power Summit 2011 (October 20, 2011)

- Assessing the Competitiveness of Atlantic Canada's Renewable Energy Sector, Rothesay Energy Dialogue (October 26, 2011)

- Nova Scotia's 2012 Renewable Energy RFP: Delivering Value for Customers 8th Canadian German Wind Energy Conference (February 23, 2012)

- Employing Competition to Procure Transmission: Lessons Learned from Other Markets, IPPSA 18th Annual Conference (March 12, 2012)

- Future Opportunities for IPPs in Atlantic Canada, Halifax 2012 FIT Forum (September 24, 2012)

- Procurement Programs for Long-term Contracts for Renewable Energy Projects in New England, Northeast Energy and Commerce Association, 10th Annual Renewable Energy Conference, (March 28, 2013)

List of Expert Testimony

Vermont Public Service Board, Investigation into the Development of Standard Offer Prices for Sustainably Priced Energy Enterprise Development (SPEED) Program, (Docket No. 7874), (January 2013)

Vermont Public Service Board, Investigation into the Establishment of a Standard Offer Prices for Baseload Renewable Power under the SPEED Program (Docket No. 7782), (May 2012)

Vermont Public Service Board, Investigation into the Establishment of a Standard Offer Prices for certain existing Hydroelectric Plants under the Sustainably Priced Energy Enterprise Development (SPEED) Program (Docket No. 7781), (February 2012)

Vermont Public Service Board, Investigation into the Review of a Standard Offer

Prices for Qualifying Sustainably Priced Energy Enterprise Development (SPEED) Resources (Docket No. 7780), (November 2011)

New Hampshire Public Utilities Commission, Concord Steam Corporation, Application of Public Service Company of New Hampshire for Approval of the Power Purchase Agreement with Laidlaw Berlin BioPower LLC (Docket DE 10-195), (December 2010)

Province of Quebec Superior Court, Churchill Falls (Labrador) Corporation Limited v. Hydro-Québec, Expert Report on Evaluation of the Power Purchase Contract for the Churchill Falls Project when Negotiated and under Current Market Conditions, (October 2010)

Ontario Energy Board, Hydro One Networks Inc. 2010-2011 Electricity Transmission Revenue Requirement and Rates Application, (Docket EB-2010-0002), (September 2010)

Vermont Public Service Board, Investigation Re: Establishment of a Standard Offer Program for Qualifying Sustainably Priced Energy Enterprise Development ("SPEED") Resources (Docket No. 7533), (December 2009)

United States District Court for Eastern California, Global Ampersand, LLC v. Crown Engineering & Construction, Inc., Damage Cost Analysis for Chowchilla and El Nido Biomass Projects (July 2009)

Florida Public Service Commission: Florida Power & Light Company Application for Approval of Standard Offer Contract and Tariff (Docket NO. 080193-EQ), (December 2008)

Louisiana Public Service Commission: Application of Entergy Louisiana, LLC for Approval to Repower Little Gypsy Unit 3 Electric Generating Facility and for Authority to Commence Construction and for Certain Cost Protection and Cost Recovery (Docket No. U-301922) (September 2007)

Alberta Energy and Utilities Board: Transmission Congestion Management Principles Proceeding, testified on behalf of TransAlta Corporation (EUB 2002-099)

New Brunswick Public Utilities Board: Generic Proceeding on the Need for Proposed Facilities, testified on behalf of New Brunswick Power Corporation Re: forecast of electricity market prices in New England (2001)

New Jersey Board of Public Utilities: Proceeding regarding the competitive implications of restructuring electricity markets on behalf of Orange and Rockland Utilities (1998)

New York Public Service Commission: Proceeding regarding competitive implications of restructuring electricity markets on behalf of Orange and Rockland Utilities (1997)

Federal Energy Regulatory Commission: Review of Competitive Implications of Proposed Merger between Delmarva Power & Light and Atlantic City Electric, testified on behalf of Delmarva Power & Light and Atlantic City Electric (1996)

Rhode Island Energy Facilities Siting Board: Application of Aquidneck Power Ltd. To Build a Natural Gas-fired Generating Facility (1995)

Massachusetts Department of Public Utilities: Review of the Commonwealth Electric Company's Competitive Procurement Process for Demand-Side Resources, testified on behalf of Commonwealth Electric Company (91-234)

Massachusetts Energy Facilities Siting Council: Review of Application by MassPower to build an electric generating facility, testified on behalf of MassPower on the Need and Impacts relative to alternative generation technologies of the proposed project (20 DOMSC 301 (1990))

Massachusetts Energy Facilities Siting Council: Review of Application by Northeast Energy Associates to build an electric generating facility, testified on behalf of Northeast Energy Associates on the impacts and costs relative to alternative generation technologies (16 DOMSC 335 (1987))

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

Prepared for:

Nova Scotia Department of Energy

April 17, 2013

Power Advisory LLC

poweradvisoryllc.com
978 369-2465

Table of Contents

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 0.9 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 per 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, at the emissions intensity level of natural gas combined cycle technology, for new coal-fired units 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 *Federal 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 Agreement* or revert to federal

[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

regulations. Regardless of which path 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 (the Maritime Link scenario).
- 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 (the Hydro-Quebec Contract scenario). 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 (the Domestic Generation scenario).

[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 Maritime Link scenario is less expensive than either of the two alternatives. On a net present value basis, as shown in Table ES- 1, the Maritime Link scenario is projected to be $342 million less expensive (in 2017 dollars) than the Hydro-Quebec Contract scenario, and $1.480 billion less expensive than the Domestic Generation scenario, over the 35-year life of the Lower Churchill Project contract (2017-2052). When a post-contract value is included assuming an additional 35 years of post-contract operation, these differences increase to $412 million and $2.243 billion respectively. 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 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 Maritime Link scenario) may be somewhat higher.

Table ES- 1: Relative Cost of Primary Supply Alternatives above the Cost of Maritime Link

($ million, in 2017 $)	Net Present Value Contract Period (2017-2052)	Including Post-Contract Value
Hydro-Quebec Contract vs. Maritime Link	$342	$412
Domestic Generation vs. Maritime Link	$1,480	$2,243

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 test the robustness of the results and assess whether there are factors which could potentially affect the conclusions of the 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 Maritime Link scenario was found to be the most cost-effective in all sensitivity cases. In comparing the Maritime Link 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 system improvements to allow up to 500 MW (rather than the base case assumption of 300 MW) to be imported over the Maritime Link, and that such power would be available on a non-firm basis.

In addition to sensitivity cases based on changes in external factors, such as demand and fuel prices, two sensitivity cases were run based on variations in the alternative supply scenarios. Decreasing the size of the expansion of the Quebec-New Brunswick-Nova Scotia interties in the Hydro-Quebec Contract scenario from 500 MW to 300 MW was found to increase the cost of this scenario to $973 million when the post-contract value is considered. While there would be a reduction in the cost of the transmission upgrades, this would be more than offset by the reduction in value from the reduced ability to import market priced energy.

If Nova Scotia's regulations were changed to require that only 25% of electricity demand come from renewable sources, rather than 40% after 2020, the cost of the Domestic Generation scenario would decrease by $472 million when the post-contract value is considered. However, the Domestic Generation scenario would still be $1.77 billion more costly than the Maritime Link scenario and would have even greater difficulty in meeting the emissions requirements.

Only the post-contract analysis considers the significant 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. The lack of a firm transmission path from Muskrat Falls through Quebec and the transmission arrangements negotiated with Emera are likely to cause Nalcor to use the Maritime Link to access the New England market rather than the Hydro-Quebec TransEnergie transmission network. 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)		ML vs. Hydro-Quebec Contract				ML vs. Domestic Generation			
		2017-2052		2017-2087		2017-2052		2017-2087	
Factor	Range	Low	High	Low	High	Low	High	Low	High
Base Case		**$342**		**$412**		**$1,480**		**$2,243**	
ML Market Import Capability	1.7* / 4.4 TWh/year	$119	$1,077	$189	$1,612	$1,257	$2,215	$2,020	$3,444
Demand	±15%**	$616	$1,215	$729	$1,789	$1,019	$2,972	$1,861	$4,123
U.S. Gas Prices	±20%	$171	$494	$304	$510	$1,430	$1,563	$2,252	$2,229
N.S. Gas Prices	Domestic Supply	$647	n/a	$882	n/a	$1,084	n/a	$1,729	n/a
Carbon Prices	RGGI only	$286	n/a	$353	n/a	$1,513	n/a	$2,280	n/a
Coal Prices	±20%	$381	$385	$422	$513	$1,433	$1,521	$2,130	$2,277
HQ Transmission Capacity	300 MW	$560	n/a	$973	n/a	n/a	n/a	n/a	n/a
Renewables Requirement	25%	n/a	n/a	n/a	n/a	$1,050	n/a	$1,771	n/a

*In the Low ML Market Import Capability case, market import capability varies from 2.6 TWh/year (300 MW at all times) in 2018 to 1.7 TWh/year (194 MW at all times) in 2040 , then returns to 2.6 TWh/year in 2042 on.
**In the High Demand case, ML Market Import Capability is increased to 4.4 TWh/year (500 MW at all times).

Source: Power Advisory

In addition, these analyses may be understating Maritime Link'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; 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.[6] 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 from the Sable Offshore Energy Project and Deep Panuke Project 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 Maritime Link scenario is the most cost-effective of the three alternatives under the full range of 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 Maritime Link 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 Maritime Link 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 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 Contract promotes this objective the least.

- The reliability goal is focused on adding another connection to electricity supplies to support the diversity objective. The Maritime Link best satisfies this goal. The Maritime Link would offer greater scheduling capability than the Hydro-Quebec Contract and Domestic Generation alternatives. We assumed that Hydro-Quebec would be willing to provide on-peak deliveries seven days a week. 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.

[6] In fact, NS Power indicated that it contacted Hydro-Quebec to assess their interest in providing a long-term fixed price for renewable power similar to what has been offered by Nalcor and "concluded that there was no long-term fixed price energy available from Hydro-Québec." See Exhibit M-11, NSPML Response to NSUARB Information Request, IR-51.

- Both the Maritime Link 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 in all sensitivity cases 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 performs the worst and the Hydro-Quebec Contract scenario doesn't perform as well as the Maritime Link.

- The Maritime Link 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

	Maritime Link	**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.[7] In addition to committing the province to having renewables provide 25% of all electricity by 2015%,[8] 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 2011 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 per 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* is strengthening security through diversity.[9] 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.

[7] http://www.gov.ns.ca/energy/renewables/renewable-electricity-plan/
[8] This commitment was codified in Regulation by the *Renewable Electricity Regulations* (N.S. Reg. 155/2010), s.6.
[9] Nova Scotia Department of Energy, April 2010, page 8.

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 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 recognizes 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, NS Power's sulphur dioxide (SO_2) emissions will be reduced by 75% relative to its initial SO_2 cap;
- By 2020, NS Power's oxides of nitrogen (NO_x) emissions will be reduced by 44% from a 2000 baseline:
- By 2020,mercury emissions will see a 84% reduction from the baseline;[10] and
- The Province of Nova Scotia is exploring new reductions after 2020 for air pollutants 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 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.

[10] 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 and 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*.[11]

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.

[11] 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.

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* identifies 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 NS Power 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 set rates later this year.[12]

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 developed 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 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, thus promoting 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

[12] 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%).[13] 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 per year). This subsea transmission (the Maritime Link) would be 100% owned by Emera through a regulated utility (NSP 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 per 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*).[14] 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

[13] The ultimate ownership percentages may vary depending on the relative costs of Muskrat Falls and the Maritime Link.
[14] http://gazette.gc.ca/rp-pr/p2/2012/2012-09-12/html/sor-dors167-eng.html

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 to 2030.

The Government of Canada also intends to develop regulations for natural gas-fired electricity. While it is not yet know 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 further 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 new reductions after 2020 for 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 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 (the Maritime Link scenario).
- 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 (the Hydro-Quebec Contract scenario). 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.
- 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 (the Domestic Generation scenario).

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,*[15] updated based on events that have occurred since the release of this report in June 2012. The

[15] 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".[16] 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.
- 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 120 MW, except in the Maritime Link scenario. The Maritime Link will supply power to Nova Scotia's transmission network at a point close to the location of the Lingan plant.
- The remaining coal units (including Lingan 3 in the Maritime Link scenario) may be retired if and when they are replaced by similar quantities of gas-fired Combined Cycle Gas Turbine (CCGT) generating units. The decision to add CCGTs and retire coal plants is part of the model's optimization process.
- 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] http://www.nsuarb.ca/index.php?option=com_content&task=view&id=73&Itemid=82 , Docket #: M04972 Exhibit #: N-103 PDF pages 6-8

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 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 regulation service or operating reserves may be 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 regulation service and 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.[18] 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 combined federal and provincial corporate tax rate in Nova Scotia (31%), long term bond interest rate (assumed to be 5% for most capital investments, and 4% for the Maritime Link 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 Maritime Link due to the federal loan guarantee). Fixed operating and maintenance costs are also included in these annual costs. The net present value was calculated based on a societal discount rate of 6%.

[17] $10/MWh is the estimate in the 2009 IRP Update Basic Assumptions that were developed jointly by NS Power and UARB staff and consultants, 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.

[18] This is based on Power Advisory's review of flows on this intertie.

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: Maritime Link

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 Newfoundland, and between Newfoundland and Nova Scotia. Nova Scotia will pay 20% of the project's costs, estimated to be $1.5 billion[19], 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 is projected to be in excess of $100M.

This investment will entitle Nova Scotia to receive a "Base Block" of about 900 GWh per 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)
- 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 per year as 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 associated transmission lines. These are estimated to amount to 1% of

[19] 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

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, up to 300 MW of power that is delivered through the Maritime Link can remain in Nova Scotia without system upgrades.[20] 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 (with a portion supplied to Nova Scotia as the Supplemental Block in the first five years only). This represents approximately 1.8 TWh per 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 5,428-MW Churchill Falls project. Nova Scotia could purchase power from either Nalcor (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 or Labrador.

The cost of these extra imports is assumed to be based on "netback" market prices at the time – i.e., prices at ISO-New England's Mass Hub, adjusted for transmission charges and losses

[20] NSPML, Maritime Link Project Application, p. 135

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 at the point where the Hydro-Quebec TransEnergie's lines interconnect with these markets, 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 for the Phase I/II line, plus transmission charges and losses through New Brunswick.[21]

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.

After the Maritime Link contract period ends in 2052, it is assumed that Nova Scotia will no longer receive the Base Block. Instead, Nova Scotia is assumed to be able to purchase up to 300 MW from Newfoundland on a non-firm basis at market prices. In order to ensure that the electricity system has adequate capacity to replace the Base Block, a 160-MW gas turbine plant is assumed to be built in Nova Scotia.

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

[21] Under locational marginal pricing marginal loss differentials are embedded in LMPs so the losses on these facilities would be reflected in the LMP at the node where they interconnect with the ISO-NE market.

- 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.[22]
- 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.[23]
- Availability: Although Hydro-Quebec appears to be open to long-term contracts,[24] they appear to favour market-based pricing rather than the long-term 35-year price certainty offered by Nalcor.[25]
- 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 153.6 MW of firm baseload capacity and associated energy between 7 am and 11 pm each day, with a daily volume of 2.46 GWh and an annual volume of 0.9 TWh, the same as the Maritime Link Base Block. Unlike the Base Block, contract supply from Hydro-Quebec is not assumed to be dispatchable.
- Upgrades that would secure sufficient transmission capacity between Quebec and Nova Scotia have been estimated to cost $1.05 billion, but Nova Scotia might not be entirely responsible for these costs.[26] Quebec and New Brunswick could derive some benefit from these upgrades (replacing aging infrastructure, improving system reliability, etc.) and could presumably share in the cost. WKM Energy provided two estimates of what Nova Scotia's share of these costs could be.. In the "maximum cost allocation" scenario, Nova Scoatio would pay an estimated $150 million for work in Nova Scotia itself and $838 million for work in New Brunswick through a direct capital contribution to NB Power, as well as paying New Brunswick transmission charges. In the "least cost allocation" scenario, some of the benefit of the upgrades is assumed to be attributed to New Brunswick and Quebec, leaving Nova Scotia responsible for $150 million for costs

[22] 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.
[23] WKM Energy Consultants Inc., "An Assessment of the Costs and Issues Associated with the Delivery of a Purchase from Hydro Quebec", December 2012.
[24] 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 power is reportedly under negotiation, but the general terms have not been disclosed.
[25] 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.
[26] 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".

within Nova Scotia itself, plus a direct capital contribution of $365 million, plus transmission charges.[27] The "least cost allocation" scenario is assumed for modelling purposes, so the total up-front cost to Nova Scotia is estimated to be $515 million (in 2015 dollars). 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.

- This cost allocation is based on the assumption that Nova Scotia will secure 500 MW of transmission service between Quebec and Nova Scotia, with the cost based on estimates by WKM Energy Consultants Inc.[28] 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 Maritime Link scenario. Purchases under Nova Scotia's contract with Hydro-Quebec are assumed to be subject to a fixed transmission charge, as estimated by WKM Energy Consultants Inc.; the energy price therefore factors in New Brunswick transmission losses but not transmission charges. Market-priced imports are assumed to be subject to New Brunswick transmission charges and losses.
- 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 154 MW of firm capacity under contract.
- 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 or renewable energy.[29] For example, there are likely to be periods when the

[27] 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.
[28] WKM Energy Consultants Inc., p. 20.
[29] Interestingly, Connecticut has proposed establishing a new class of renewable energy which would include large scale hydro from Canada and be eligible for long-term contracts. This suggests that assuming

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.

The term of the Hydro-Quebec contract is assumed to match that of the Maritime Link contract. After the contract period ends in 2052, it is assumed that Nova Scotia will no longer receive power from Hydro-Quebec under contract. Instead, Nova Scotia is assumed to be able to purchase up to 600 MW (500 MW over the new intertie and 100 MW over the existing one) from Quebec or other sources on a non-firm basis at market prices. In order to ensure that the electricity system has adequate capacity to replace the Hydro-Quebec contract, a 160-MW gas turbine plant is assumed to be built in Nova Scotia.

As a sensitivity case, we have included a variation on the Hydro-Quebec Contract scenario based on a smaller transmission path from Quebec, through New Brunswick, to Nova Scotia: 300 MW instead of 500 MW. This means that market imports are limited to 146 MW (plus 100 MW over the existing intertie) when contract energy is being supplied. The cost of the required transmission upgrades is assumed to be 60% of the costs in the primary scenario. This may be optimistic, as there are likely to be economies of scale in constructing a 500-MW transmission path relative to a 300-MW path.

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 that could be attributable to additional gas generation on this scale requiring substantial upgrades to the gas pipelines connecting Nova Scotia to the rest of eastern North America, once the gas in the Sable Offshore Energy Project and Deep Panuke Project runs out. Upgrading or twining these gas lines could cost many hundreds of millions of dollars.

---

no premium for the renewable attributes offered by the Hydro-Quebec Contract may understate its true market value and that Hydro-Quebec may require such a premium to enter into a long-term contract. http://www.dpuc.state.ct.us/DEEPEnergy.nsf/c6c6d525f7cdd1168525797d0047c5bf/67d62db9c92d7f6885257b320066e509?OpenDocument

As a sensitivity case, we have included a variation on the Domestic Generation scenario in which Nova Scotia's requirement for renewable electricity supply is kept at 25% of demand, instead of increasing to 40% in 2020. This means that no additional wind would be needed at that time. Instead, gas-fired CCGTs are built. Some additional wind is built in this scenario, but based on it being the more economical source of supply, rather than due to government regulation. This "Low Renewables" scenario is not included as a primary scenario because it does not meet all of Nova Scotia's regulatory requirements.

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). For natural gas, the forecast used was for the electric power sector in New England.[30] 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:

- Gas transmission and delivery costs between New England (specifically, 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.

- 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

[30] The EIA natural gas forecast for 2017 is $4.98/MMBtu, which is $0.81/MMBtu, 14%, below the April 8th futures price for Tennessee at Dracut.

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 $/MMBtu	NS Pet Coke $/MMBtu	NE Gas $/MMBtu	NS Gas $/MMBtu	NS Diesel $/MMBtu	NE Carbon $/tonne	NE Energy $/MWh	NE Capacity $/kW-yr
2017	$5.43	$4.07	$5.21	$6.81	$27.25	$3.43	$48.63	$43.70
2018	$5.55	$4.16	$5.64	$7.27	$28.21	$3.50	$51.99	$50.37
2019	$5.66	$4.25	$5.89	$7.56	$29.25	$3.57	$54.06	$59.17
2020	$5.81	$4.36	$6.11	$7.82	$30.29	$11.12	$58.87	$68.31
2021	$5.97	$4.47	$6.25	$7.99	$31.40	$11.34	$60.11	$77.79
2022	$6.14	$4.61	$6.56	$8.34	$32.53	$11.57	$62.66	$82.75
2023	$6.31	$4.73	$6.82	$8.64	$33.73	$11.80	$64.79	$84.40
2024	$6.48	$4.86	$7.10	$8.96	$34.96	$12.03	$67.00	$86.09
2025	$6.65	$4.99	$7.32	$9.22	$36.29	$12.27	$68.84	$87.81
2026	$6.83	$5.12	$7.75	$9.69	$37.58	$12.52	$71.98	$89.57
2027	$7.01	$5.26	$7.95	$9.92	$38.93	$12.77	$73.69	$91.36
2028	$7.20	$5.40	$8.20	$10.22	$40.33	$13.03	$75.79	$93.19
2029	$7.39	$5.54	$8.47	$10.54	$41.78	$13.29	$77.98	$95.05
2030	$7.60	$5.70	$8.76	$10.87	$43.24	$13.55	$80.29	$96.95
2031	$7.79	$5.84	$9.14	$11.29	$44.74	$13.82	$83.17	$98.89
2032	$7.99	$5.99	$9.45	$11.64	$46.26	$14.10	$85.62	$100.87
2033	$8.19	$6.15	$9.81	$12.05	$47.93	$14.38	$88.43	$102.89
2034	$8.41	$6.31	$10.29	$12.59	$49.72	$14.67	$92.10	$104.95
2035	$8.65	$6.49	$10.85	$13.20	$51.65	$14.96	$96.22	$107.05
2036	$8.88	$6.66	$11.50	$13.90	$53.68	$15.26	$100.90	$109.19
2037	$9.12	$6.84	$12.07	$14.53	$55.76	$15.57	$105.21	$111.37
2038	$9.36	$7.02	$12.85	$15.37	$57.60	$15.88	$110.73	$113.60
2039	$9.60	$7.20	$13.34	$15.91	$59.81	$16.20	$114.44	$115.87
2040	$9.85	$7.39	$14.04	$16.67	$61.99	$16.52	$119.42	$118.19
2041	$10.05	$7.54	$14.32	$17.00	$63.23	$16.85	$121.80	$120.55
2042	$10.25	$7.69	$14.61	$17.34	$64.49	$17.19	$124.24	$122.96
2043	$10.45	$7.84	$14.90	$17.69	$65.78	$17.53	$126.73	$125.42
2044	$10.66	$8.00	$15.20	$18.04	$67.10	$17.88	$129.26	$127.93
2045	$10.88	$8.16	$15.50	$18.40	$68.44	$18.24	$131.84	$130.49
2046	$11.09	$8.32	$15.81	$18.77	$69.81	$18.60	$134.48	$133.10
2047	$11.32	$8.49	$16.13	$19.15	$71.20	$18.98	$137.17	$135.76
2048	$11.54	$8.66	$16.45	$19.53	$72.63	$19.35	$139.91	$138.47
2049	$11.77	$8.83	$16.78	$19.92	$74.08	$19.74	$142.71	$141.24
2050	$12.01	$9.01	$17.12	$20.32	$75.56	$20.14	$145.57	$144.07
2051	$12.25	$9.19	$17.46	$20.73	$77.07	$20.54	$148.48	$146.95
2052	$12.49	$9.37	$17.81	$21.14	$78.62	$20.95	$151.45	$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 allowance program: New England carbon prices from 2020 on are based on RGGI (around $3 per metric tonne in 2012 dollars).
- 20% lower coal prices.
- 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 (tonnes)	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	11,500	40%
2026	5.70	28,000	35	11,500	40%
2027	5.40	28,000	35	11,500	40%
2028	5.10	28,000	35	11,500	40%
2029	4.80	28,000	35	11,500	40%
2030	4.50	20,000	30	8,800	40%
2031	4.39	20,000	30	8,800	40%
2032	4.28	20,000	30	8,800	40%
2033	4.16	20,000	30	8,800	40%
2034	4.05	20,000	30	8,800	40%
2035	3.94	20,000	30	8,800	40%
2036	3.83	20,000	30	8,800	40%
2037	3.71	20,000	30	8,800	40%
2038	3.60	20,000	30	8,800	40%
2039	3.49	20,000	30	8,800	40%
2040	3.38	20,000	30	8,800	40%
2041	3.26	20,000	30	8,800	40%
2042	3.15	20,000	30	8,800	40%
2043	3.04	20,000	30	8,800	40%
2044	2.93	20,000	30	8,800	40%
2045	2.81	20,000	30	8,800	40%
2046	2.70	20,000	30	8,800	40%
2047	2.59	20,000	30	8,800	40%
2048	2.48	20,000	30	8,800	40%
2049	2.36	20,000	30	8,800	40%
2050	2.25	20,000	30	8,800	40%
2051	2.25	20,000	30	8,800	40%
2052	2.25	20,000	30	8,800	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 Maritime Link 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 Maritime Link scenario is projected to be $342 million less expensive (in 2017 dollars) than the Hydro-Quebec Contract scenario, and $1.480 billion less expensive than the Domestic Generation scenario. The net present value calculations are based on a societal discount rate of 6%.[31] 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 Maritime Link scenario) may be somewhat higher. This is discussed in more detail below.

The Maritime Link and the Quebec-New Brunswick-Nova Scotia transmission upgrades assumed in the Hydro-Quebec Contract scenario would remain in service after the associated contracts end, and would continue to offer the opportunity for market-priced imports. To capture the post-contract value of these assets, costs were extrapolated for an additional 35 years (i.e., 2053-2087). In both the Maritime Link and Hydro-Quebec Contract scenarios, a 160-MW gas turbine plant was added to replace the 154 MW of firm contract capacity. With the post-contract values included, the Maritime Link scenario's advantage increased to $412 million compared to the Hydro-Quebec Contract scenario, and $2.243 billion compared to the Domestic Generation scenario.

Only the post-contract analysis considers the significant 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. The lack of a firm transmission path from Muskrat Falls through Quebec and the transmission arrangements negotiated with Emera are likely to cause Nalcor to use the Maritime Link to access the New England market rather than the Hydro-Quebec TransEnergie transmission network. 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 the Maritime Link'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.

[31] 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.

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 Offshore Energy Project and Deep Panuke Project 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 Maritime Link scenario is the most cost-effective of the three alternatives under the full range of market conditions evaluated which represent a reasonable range of future market conditions.

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, replacing Lingan with a gas-fired CCGT in the same area would require a substantial gas transmission investment.

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 model results indicate 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 in the Domestic Generation scenario, particularly between 2030 and 2035. 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 Maritime Link 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 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 2.6 TWh per year (i.e., 300 MW at all times, including the Base Block and, during the first five years, the Supplemental Block)
    - Low: Electricity available for import (either under contract or through purchase at market rates) from Newfoundland falls from 2.6 TWh per year in 2018 to 1.7 TWh per year by 2040 (i.e., 194 MW at all times, including 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 import up to 4.4 TWh per year of electricity over the Maritime Link – i.e., up to 500 MW at all times, including the Base Block (and Supplemental Block in 2018-2022). Imports 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 assumed to be $100 million, which is $30 million higher than Emera's low end estimate.[32]
- 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 Maritime Link Base and Supplemental Blocks.
    - Low: RGGI-only prices (around $3/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

[32] NSPML Response to NS Department of Energy Information Request, IR-8 b.

- 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 Maritime Link scenario, therefore, it is assumed that Nova Scotia would invest in system improvements 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 test the robustness of the results and assess whether there are factors which could potentially affect the conclusions of the 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 Maritime Link scenario was found to be the most cost-effective in all sensitivity cases.

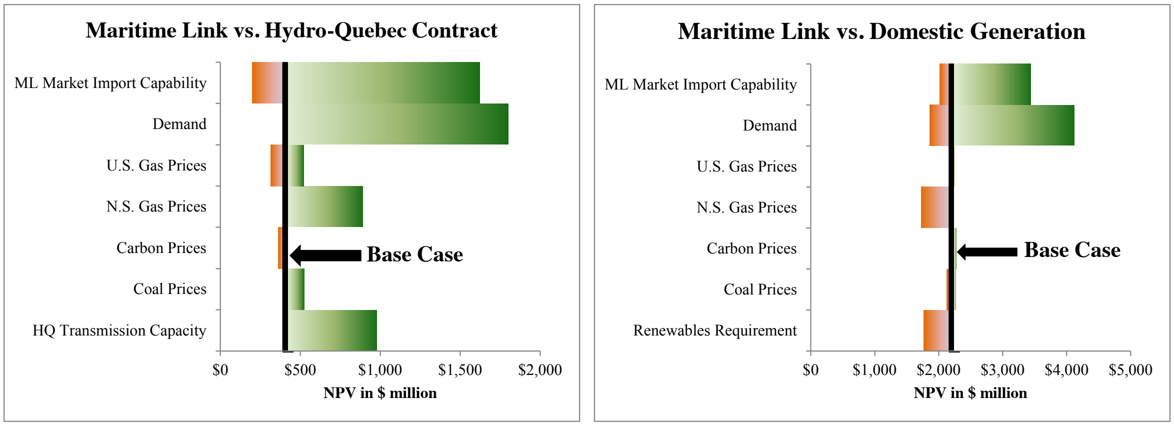
Table 4: Sensitivity Case Results

(NPV in $ million)		ML vs. Hydro-Quebec Contract				ML vs. Domestic Generation			
		2017-2052		2017-2087		2017-2052		2017-2087	
Factor	Range	Low	High	Low	High	Low	High	Low	High
Base Case		$342		$412		$1,480		$2,243	
ML Market Import Capability	1.7* / 4.4 TWh/year	$119	$1,077	$189	$1,612	$1,257	$2,215	$2,020	$3,444
Demand	±15%**	$616	$1,215	$729	$1,789	$1,019	$2,972	$1,861	$4,123
U.S. Gas Prices	±20%	$171	$494	$304	$510	$1,430	$1,563	$2,252	$2,229
N.S. Gas Prices	Domestic Supply	$647	n/a	$882	n/a	$1,084	n/a	$1,729	n/a
Carbon Prices	RGGI only	$286	n/a	$353	n/a	$1,513	n/a	$2,280	n/a
Coal Prices	±20%	$381	$385	$422	$513	$1,433	$1,521	$2,130	$2,277
HQ Transmission Capacity	300 MW	$560	n/a	$973	n/a	n/a	n/a	n/a	n/a
Renewables Requirement	25%	n/a	n/a	n/a	n/a	$1,050	n/a	$1,771	n/a

*In the Low ML Market Import Capability case, market import capability varies from 2.6 TWh/year (300 MW at all times) in 2018 to 1.7 TWh/year (194 MW at all times) in 2040 , then returns to 2.6 TWh/year in 2042 on.
**In the High Demand case, ML Market Import Capability is increased to 4.4 TWh/year (500 MW at all times).

Source: Power Advisory

Figure 1: Sensitivity Case Results 2017-2087



In comparing the Maritime Link 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 system improvements 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.

Decreasing the size of the expansion of the Quebec-New Brunswick-Nova Scotia interties in the Hydro-Quebec Contract scenario from 500 MW to 300 MW would increase the cost of this scenario to $973 million when the post-contract value is considered. While there would be a reduction in the cost of the transmission upgrades (assumed to be 40%, though this may be optimistic), this would be more than offset by the reduction in value from the reduced capability to import energy at market prices.

If Nova Scotia's regulations were changed to require that only 25% of electricity demand come from renewable sources, rather than 40% after 2020, the cost of the Domestic Generation scenario would decrease by $472 when the post-contract value is considered. However, the Domestic Generation scenario would still be $1.77 billion more costly than the Maritime Link scenario and have difficulty meeting emissions requirements.

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.
- 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 Maritime Link 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.[33] 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 that the Maritime Link does. Therefore, the Hydro Quebec Contract promotes this objective the least.

- The reliability goal is focused on adding another connection to electricity supplies to support the diversity objective. The Maritime Link 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

[33] In fact, the Maritime Link would also provide access to energy from Churchill Falls including the 300 MW that is available to Nalcor under the Recall Block.

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 the Maritime Link and a Hydro-Quebec contract would offer greater scheduling capability than the additional domestic supply alternative.

- Both the Maritime Link scenario and the Domestic Generation scenario are likely to provide greater flexibility and offer greater price stability than a Hydro-Quebec Contract. The Maritime Link provides access to both a block of fixed and market-priced energy. Offering access to energy under two distinct pricing regimes ensures that the Maritime Link is competitively priced under a wide range of market conditions, causing it to be a robust supply alternative. Under high energy prices the fixed price block would be more valuable and with low energy prices the market-priced energy would be attractive. 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 the Maritime Link. 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 Maritime Link 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

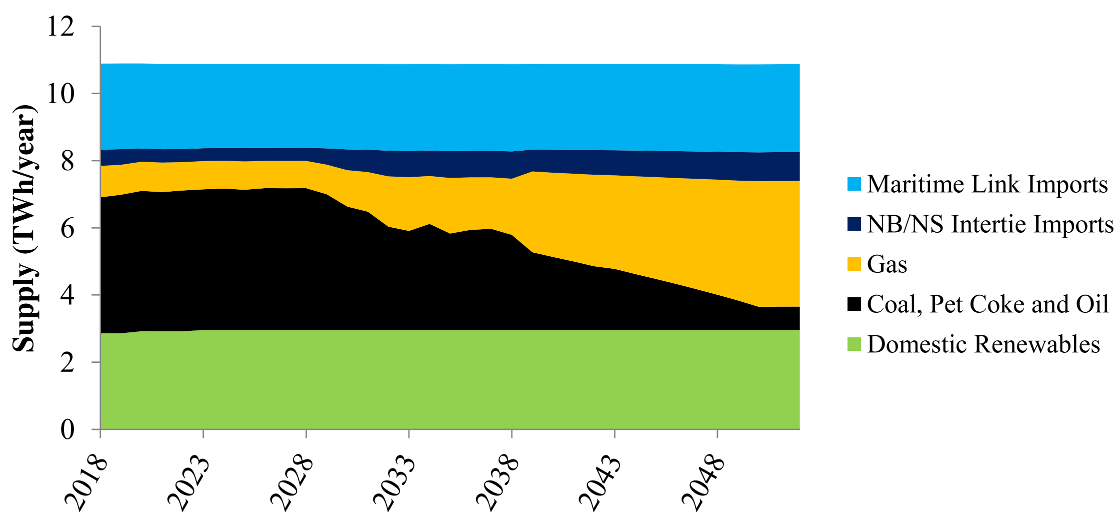
	Maritime Link	Hydro Quebec Contract	Domestic Generation
Diversity of Supply	2	3	1
Reliability	1	2	3
Flexible Supply to Maintain Competitive Prices	1	2	3
Achievement of GHG emission and other air pollutant obligations and renewable energy commitments	1	1	3

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

This comparison suggests that the Maritime Link Project best satisfies these strategic policy goals.

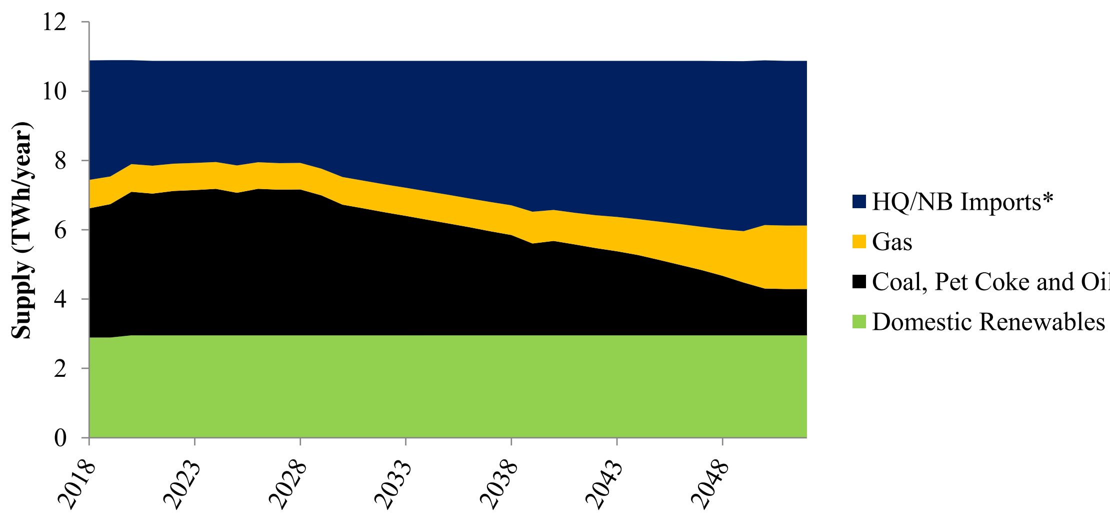
Appendix A: Modeling Results for the Optimal Supply Scenario with Maritime Link

	2020	2025	2030	2035	2040	2045	2050
Electricity Supply (TWh)							
Coal, Pet Coke and Oil	4.18	4.18	3.68	2.87	2.18	1.52	0.69
Gas	0.87	0.84	1.08	1.65	2.51	3.03	3.74
Domestic Renewables	2.92	2.96	2.96	2.96	2.96	2.96	2.96
Maritime Link Imports	2.53	2.50	2.54	2.59	2.55	2.58	2.62
NB/NS Intertie Imports	0.39	0.40	0.62	0.80	0.68	0.78	0.86
Total	**10.89**	**10.87**	**10.87**	**10.87**	**10.87**	**10.87**	**10.87**
Emissions							
CO2e (million tonnes)	4.96	4.93	4.50	3.64	3.37	2.81	2.25
Sulphur (tonnes)	32,627	27,999	19,541	20,011	18,043	14,323	7,172
Mercury (kg)	35	35	30	30	20	17	9
NOx (tonnes)	8,650	8,654	8,068	8,045	6,466	6,167	6,052
Emissions vs. Caps							
CO2e Cap	-34%	-18%	0%	-8%	0%	0%	0%
Sulphur Cap	-10%	0%	-2%	0%	-10%	-28%	-64%
Mercury Cap	0%	0%	0%	0%	-32%	-45%	-72%
NOx Cap	-42%	-25%	-8%	-9%	-27%	-30%	-31%



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

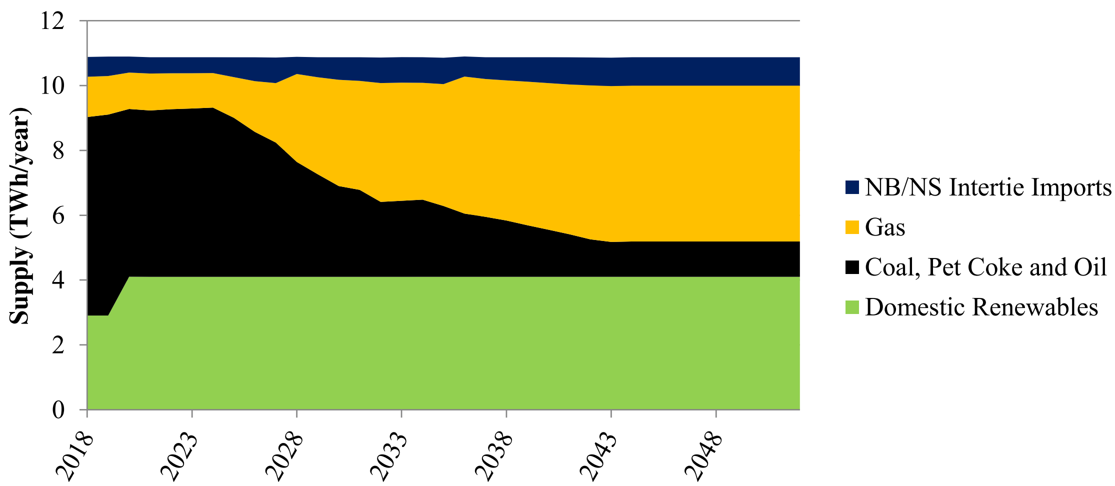
	2020	2025	2030	2035	2040	2045	2050
Electricity Supply (TWh)							
Coal, Pet Coke and Oil	4.14	4.11	3.77	3.23	2.72	2.18	1.35
Gas	0.80	0.79	0.80	0.83	0.89	1.10	1.83
Domestic Renewables	2.95	2.95	2.95	2.95	2.95	2.95	2.95
HQ/NB Imports*	3.00	3.02	3.35	3.86	4.30	4.64	4.75
Total	**10.89**	**10.87**	**10.87**	**10.87**	**10.87**	**10.87**	**10.89**
Emissions							
CO2e (million tonnes)	4.96	4.90	4.50	3.94	3.35	2.81	2.25
Sulphur (tonnes)	36,021	27,995	19,737	19,566	20,000	19,512	15,132
Mercury (kg)	35	35	30	30	30	29	18
NOx (tonnes)	9,209	9,147	8,448	7,344	6,431	5,844	4,781
Emissions vs. Caps							
CO2e Cap	-34%	-18%	0%	0%	-1%	0%	0%
Sulphur Cap	-1%	0%	-1%	-2%	0%	-2%	-24%
Mercury Cap	0%	0%	0%	0%	0%	-5%	-40%
NOx Cap	-38%	-20%	-4%	-17%	-27%	-34%	-46%



*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	5.17	4.90	2.80	2.18	1.45	1.09	1.09
Gas	1.12	1.26	3.28	3.76	4.52	4.81	4.81
Domestic Renewables	4.10	4.10	4.10	4.10	4.10	4.10	4.10
NB/NS Interie Imports	0.49	0.61	0.69	0.81	0.80	0.88	0.88
Total	**10.89**	**10.87**	**10.87**	**10.86**	**10.87**	**10.87**	**10.87**
Emissions							
CO2e (million tonnes)	6.25	6.00	4.50	3.94	3.38	3.12	3.12
Sulphur (tonnes)	36,230	27,564	19,384	19,092	16,008	12,705	12,705
Mercury (kg)	35	35	28	27	19	15	15
NOx (tonnes)	11,673	11,235	9,323	9,451	7,517	7,446	7,446
Emissions vs. Caps							
CO2e Cap	-17%	0%	0%	0%	0%	11%	39%
Sulphur Cap	0%	-2%	-3%	-5%	-20%	-36%	-36%
Mercury Cap	0%	0%	-7%	-9%	-37%	-49%	-49%
NOx Cap	-22%	-2%	6%	7%	-15%	-15%	-15%



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).