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Forensic Audit Report to the Commission of Inquiry Respecting the Muskrat Falls Project

Sanctioning Phase – July 16, 2018

Grant Thornton

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July 16, 2018

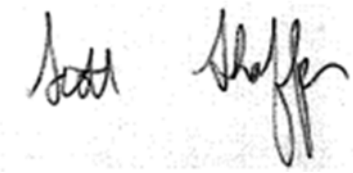
Dear Commissioner LeBlanc:

FORENSIC AUDIT REPORT – SANCTIONING PHASE

We enclose our report of the findings and observations with respect to the forensic audit of the Sanctioning Phase of the Muskrat Falls Project.

We would like to take this opportunity to thank the Commission, Nalcor and the Province for their support throughout this project. We would also like to thank all current and past employees and contractors of Nalcor, other participants and their respective legal counsel for their co-operation throughout this engagement.

Yours sincerely,
Grant Thornton LLP



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Background

In 2007, the Government of Newfoundland and Labrador ("GNL") released the Provincial Energy Plan ("Energy Plan"). The Energy Plan refers to the development of the Lower Churchill as a cornerstone public policy action. The Energy Plan defined its objectives as protecting the environment, developing the Province's resources in the best long-term interest of the people of the province and meeting the electricity needs of the Province with environmentally friendly, stable and competitively priced power.

The Lower Churchill Project ("LCP") was undertaken by Nalcor Energy ("Nalcor") the Newfoundland and Labrador crown corporation which owns Muskrat Falls Corporation with Emera Inc. (a company based in Nova Scotia). The following is a summary of the components of the Muskrat Falls Project ("Project" or "Muskrat Falls"):

- Muskrat Falls Generating ("MFG") facility, an 824 megawatt ("MW") hydroelectric generating facility consisting of two dams and a powerhouse at Muskrat Falls;
- Labrador-Island transmission link ("LIL"), an 1,100 kilometre (km) High Voltage direct current ("HVdc") transmission line from Muskrat Falls to Soldiers Pond on the Avalon Peninsula, including a 35 km subsea cable across the Strait of Belle Isle;
- Labrador transmission assets ("LTA"), two 250 km High Voltage alternating current ("HVac") transmission lines between Muskrat Falls and Churchill Falls; and
- Maritime Link (ML), a 500MW HVdc transmission link between Newfoundland and Nova Scotia.

This report focuses on the components of the Project undertaken by Nalcor, and as such, excludes the ML component which was undertaken by Emera.

At the time the Project was sanctioned in 2012, the capital cost estimate amounted to approximately $6.2 billion (excluding financing costs) with first power from Muskrat Falls scheduled for 2017. To date, excluding financing costs, the capital cost estimate has been revised and is currently in excess of $10.1 billion[1] and first power from Muskrat Falls is not scheduled to occur until 2019 (full power in 2020).[2] Due to the cost overruns, schedule delays and the public's request for greater transparency, the provincial government established the Commission of Inquiry Respecting the Muskrat Falls Project ("Commission").

In February 2018, Grant Thornton was engaged by the Commission to conduct a forensic audit and to prepare a report of the findings ("Forensic Audit").

[1] NAL0020789 – Monthly Construction Report MFG & LTA – December 31, 2017
NAL0020767 – Monthly Construction Report LIL – December 31, 2017
[2] Nalcor – Understanding Muskrat Falls – Stan Marshall, CEO Nalcor Energy – February 15, 2018

Scope of Work

In accordance with our engagement letter with the Commission, our Forensic Audit is divided into two distinct phases:

1 Sanctioning Phase – Decision Gate 2 ("DG2") (November 16, 2010) to the Decision Gate 3 ("DG3") sanctioning decision (December 17, 2012); and

2 Construction Phase - December 18, 2012 to present.

Each phase will have its own report. This report is limited to the Sanctioning Phase. A subsequent report will be issued related to the Construction Phase which will include events occurring after December 17, 2012 including, but not limited to, financial close, third party risk assessments and construction activity.

The period of our analysis covered by this report is as of the date of the DG2 Support Package approval on November 16, 2010, (including where applicable an analysis of the information and supporting documentation referenced therein) up to sanctioning on December 17, 2012 ("Period of Review").

The engagement has been conducted in accordance with the Standard Practices for Investigative and Forensic Accounting Engagements of the Chartered Professional Accountants of Canada and was led and supervised by David Malamed, Forensic Accounting Partner and Scott Shaffer, Managing Director and Construction Advisory Leader.

As per our engagement letter, the Forensic Audit for the Sanctioning Phase was to include the following:

1 The options that were considered by Nalcor to address the electricity needs of Newfoundland and Labrador's Island Interconnected customers;

2 The assumptions or forecasts on which Nalcor's analysis of the options was based; and

3 Nalcor's financial analysis of both the Interconnected Island Option and the Isolated Island Option and selection of the least-cost option for the supply of power to Newfoundland and Labrador's Island Interconnected system over the period 2011-2067.

Generally, as part of our Forensic Audit, we performed the following procedures:

- Identified and reviewed supporting documentation (See Appendix B for a list of documents relied upon);
- Conducted interviews with and/or attended presentations from: Nalcor executives, the past Chair of the Board, senior management, other employees and contractors (all of whom were in their respective roles at the time of sanction); industry experts; concerned citizens; and, past members of the Muskrat Falls Oversight Committee;
- Submitted requests for information including supporting documentation and questions;
- Performed various analyses; and
- Consulted with independent experts.

From the period of DG2 to DG3, various reports were issued by third parties related to the Project. Information from some of these reports has been referenced throughout our report. We have identified the most commonly referenced reports below:

- On September 14, 2011, Navigant Consulting Ltd ("Navigant") issued a report entitled Independent Supply Decision Review (the "Navigant Report").[3]
- On June 17, 2011, the GNL directed the Newfoundland and Labrador Board of Commissioners of Public Utilities (the "P.U.B.") to review and report on whether the Muskrat Falls Project would represent the least-cost option for NL as opposed to the Isolated Island option (the "P.U.B. Review"). The P.U.B. issued its Report to Government on March 30, 2012 (The "P.U.B. Report to Government").[4] As part of the P.U.B. Review, Nalcor issued a submission in November 2011 ("Nalcor P.U.B. Submission").[5]
- As part of the P.U.B. Review, the P.U.B. engaged Manitoba Hydro International ("MHI") as its expert consultant. MHI issued a report dated January 2012 titled Report of Two Generation Expansion Alternatives for the Island Interconnected Electrical System (the "MHI January 2012 Report").[6]
- Subsequent to the P.U.B. Review, MHI was engaged by the GNL to provide an independent assessment of the two generation supply options. MHI issued its report titled Review of the Muskrat Falls and Labrador Island HVdc Link in October 2012 (the "MHI October 2012 Report").[7]

[3] NAL0018800 – Independent Supply Decision Review – September 14, 2011
[4] NAL0019060 - Reference to the Board – Review of Two Generation Expansion Options For The Least-Cost Supply of Power To Island Interconnected Customers For The Period 2011 – 2067 - March 30, 2012
[5] NAL0019056 - Nalcor's Submission to the Board of Commissioners of Public Utilities with respect to the Reference from the Lieutenant-Governor in Council on the Muskrat Falls Project – November 10, 2011
[6] NAL0018916/NAL0018917 - - Manitoba Hydro International: Report on Two Generation Expansion Alternatives for the Island Interconnected Electrical System - January 2012
[7] NAL0018691 - Review of Muskrat Falls and Labrador Island HVdc Link and the Isolated Island Options – October 2012

Restrictions and limitations

We acknowledge that our report will be submitted to the Commission and may become a public document. Our report is not to be reproduced or used for any purpose other than that outlined above without prior written permission in each specific instance. Grant Thornton LLP recognizes no responsibility whatsoever to any third party who may choose to rely on its reports or other material provided to the Commission.

Our scope of work is as set out in our engagement agreement dated February 3, 2018. The procedures undertaken in the course of our review do not constitute a financial statement audit of Nalcor's financial information and consequently, we do not express an opinion or provide any assurance on the financial information provided by Nalcor.

Unless stated otherwise, within the body of this report, Grant Thornton LLP has relied upon information provided by Nalcor and third party sources in the preparation of this report, whom Grant Thornton LLP believe to be reliable. Information was obtained from Nalcor through responses to our specific document requests, written responses prepared by Nalcor, evidence submitted by interviewees, and searches performed in the document management system administered by the Commission.

All analysis, information and findings contained herein are based upon the information made available to Grant Thornton LLP as of the date of this report and are subject to change without notice. We reserve the right, but will be under no obligation, to review and/or revise the contents of this report in light of information which becomes known to us after the date of this report. Additionally we reserve the right to prepare demonstrative exhibits at hearings.

Summary of findings/observations

The following summarizes the findings and observations from the Forensic Audit completed for the Period of Review which may have impacted the selection of the Interconnected Island Option as the least cost option when compared to the Isolated Island Option. For more detail please see the Detailed Findings and Observations Sections throughout this report. This summary is not intended to provide a complete listing of all our findings and observations.

Options Considered

- The option to import power from/via Hydro Quebec did not proceed beyond Phase One screening. Nalcor did not have formal discussions with Hydro Quebec as part of assessing this option.
- The option of waiting until 2041 (i.e. Deferred Churchill Falls option) did not proceed beyond Phase One screening based in part on a conclusion made by Nalcor related to uncertainty around availability of power from the Upper Churchill which we concluded was inconsistent with the findings of the Nova Scotia Utility and Review Board ("NSUARB").

The findings and observations noted above suggest that Nalcor may have inappropriately eliminated the options of importing power from Hydro Quebec or deferring the development of LCP until 2041 when power was available from the Upper Churchill, from proceeding to Phase Two analysis. Further analysis of these options may have led to a different decision.

Planning Load Forecast Methodology/Assumptions

- The industrial customer base was prone to forecast volatility (as evident when considering performance over the previous 10 year period) due to potential load change in customers and sensitivity to economic conditions. The industrial load was held constant over the forecast period without considering the impact of the following: elasticity; Conservation and Demand Management ("CDM"); the loss of any industrial customers; or decrease in load for any industrial customers. We note that the load forecast excluded the addition of any new industrial customers.
- Price elasticity (the effect of price on demand) was not included in Planning Load Forecast for the general service/commercial customer sector of Newfoundland and Labrador Hydro's utility customer (Newfoundland Power).
- CDM incentive based programs were not factored into the load forecast at DG2. To date we have not been provided with any support which demonstrates CDM incentive programs were incorporated into the load forecast used in DG3.
- Nalcor relied on economic forecasts provided by its shareholder's (i.e. GNL) Department of Finance. We determined the forecast for economic indicators used by Nalcor, related to population and housing starts, were different from a forecast published by The Conference Board of Canada ("CBOC") in 2012.

The findings and observations noted above may have resulted in an overstatement of the load forecast used in the sanctioning decision. The Cumulative Present Worth ("CPW") for the Isolated Island Option is more sensitive to changes in load forecast due in part to the impact of fuel costs, therefore a decrease in load forecast would have a greater impact on the CPW (i.e. a reduction in CPW) of the Isolated Island Option compared to the Interconnected Island Option. In addition, an overstatement in load forecast may impact the decision of the need and/or timing of adding generation sources.

Financial Analysis

The following relate to cost estimates of the option that was selected by Nalcor, the Interconnected Island Option (i.e. Muskrat Falls):

- Nalcor excluded approximately $500 million of strategic risk exposure from the capital cost estimate for the CPW calculation. We have been informed by Nalcor's Project Team, that strategic risk exposure was to be funded through contingent equity from GNL.
- Nalcor selected a P50 in calculating the tactical contingency included in their capital cost estimate ("CCE"). A P-factor determines the probability that cost overruns or underruns will occur. The higher the P-factor, the lower the likelihood of cost overruns (and the higher the capital cost estimate). For a Company undertaking a stand-alone project (i.e. not a portfolio of projects), an independent consultant used by Nalcor informed us that P-factors ranging from P70 to P90 are more reasonable. Had Nalcor selected a P90, the capital cost estimate would have increased by approximately $767 million. This would have resulted in a higher CPW.
- Operating and maintenance costs were forecast to be $34 million annually and included in the CPW. These costs are now forecast by Nalcor to be $109 million annually.

These findings and observations indicate a potential understatement of costs at the time of sanctioning of the Interconnected Island Option which in turn would understate the CPW of this option.

Conclusion

Based on the above findings and observations, at the time of sanctioning, there was:

1. A potential overstatement of the CPW for the Isolated Island Option; and
2. A potential understatement of the CPW for the Interconnected Island Option.

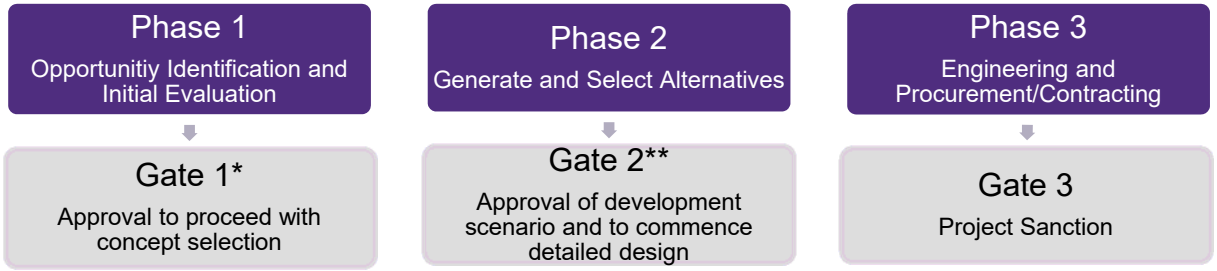
The combination of these potential misstatements may have resulted in the Interconnected Island Option (the option selected by Nalcor) no longer being considered the least cost option at the time of sanctioning.

Detailed Findings and Observations

The DG2 package identifies that the need for undertaking the LCP was to fulfill the requirements of the Energy Plan and generate positive returns for the Province and create future opportunities for the development of other resources within NL Energy Warehouse.[8] In addition, the DG2 package indicates that the need for the LCP is also being driven by Nalcor's Integrated Resource Planning which identified a need for new generation capacity by as early as 2015.[9] During interviews with the former Nalcor CEO, the CFO and the Chair of the Board at the time of sanctioning, we discussed if the development of the LCP was predetermined by the need to execute on the Energy Plan. These three individuals indicated that while Nalcor was tasked with progressing with LCP planning, the decision to proceed was not predetermined and was to be supported by a business case prior to sanction.

Nalcor selected a staged-gate approach to govern the decision making process to focus decision-making at crucial points in the project's lifecycle. Nalcor refers to this as the "Gateway Process"[10]. According to Nalcor the gateway process divides the project into phases where key deliverables are advanced and often completed. At the end of each phase, there is a "gate". In order to move to the next phase the Gatekeeper, (Nalcor CEO) needed to provide final approval prior to moving through the gate. For example, before moving to Phase 3, the gatekeeper needed to approve Gate 2. Prior to the gatekeeper's approval various approvals from Nalcor's executive and project management team were required.

The phases and gates included in the scope of sanction have been summarized in the illustration below.



**We understand that the objectives of phase one of the project had been completed prior to the Gateway Process being implemented. As a result, Nalcor was unable to provide a formal Decision Gate 1 support package.*

***We understand that Nalcor prepared two Decision Gate support packages in phase 2 of the gateway process. DG2A was completed when the LCP was focused on Gull Island development. Subsequently, the LCP switched focus to Muskrat Falls development first and the DG2 support package was prepared reflecting the change in focus of the project.*

[8] NAL0000195 - Decision Gate 2 Support Package - November 16, 2010
[9] NAL0000195 - Decision Gate 2 Support Package - November 16, 2010
[10] NAL0063739 - Gateway Process – March 24, 2009

The Steering Committee

As part of the decision gate process an external assessment was performed (July 2008) by Independent Project Analysis Inc. ("IPA").[11] Among their recommendations it was noted that the project lacked a formal steering committee[12] and that mega projects without a steering committee have worse team development and poor operability.[13]

Nalcor drafted a Steering Committee Project Charter document (MSD-PM-015) to establish guidelines and requirements of the steering committee in relation to the Lower Churchill Project.[14] The Steering Committee Project Charter defined the agreed purpose, scope and member composition for the LCP Steering committee and noted that the committee will be developed to provide overall guidance and advice to the LCP as it progresses through Gate 2 up to Full Power Delivery (post Gate 4).[15]

In response to Grant Thornton's Question 1.3, Nalcor advised that a DG2 Steering Committee endorsed the acceptance and readiness (step 2) of the DG assessment process. Nalcor also indicated that at DG3 the LCP Executive Committee endorsed the recommendation, endorsement and approval of readiness (step 2) of the DG assessment process.[16] However, during a presentation from the Muskrat Falls Project Team ("Project Team") on May 31, 2018, we were told that the draft Steering Committee Project Charter was never finalized and no overarching steering committee was ever formed.

The LCP Project Team noted that while there was no overarching steering committee, Nalcor's LCP Executive Committee reviewed and signed off on DG3 Support Package.

Nalcor's Third Party Experts

Nalcor's Gateway Process[17] references reviews conducted by third party experts. One of these reviews was the Independent Project Review ("IPR"). The role of the IPR team was to provide a "cold eyes review" of the work performed by the project team to ensure validity and assess the readiness of the package prepared to proceed to the next phase. The IPR team was to include external individuals and permitted Nalcor personnel that were not directly involved in the LCP to be part of the team.[18]

Grant Thornton Procedures

- Gained an understanding of the Gateway Process
- Identified Best Practices through research and discussions with external experts
- Reviewed process and supporting documentation

Findings and Observations

- We note that one of the IPR team members was a founder of Westney Consulting ("Westney"). Westney was also engaged by Nalcor to participate in the risk assessment of the Project. Potentially this could be viewed as a conflict of interest (whether actual or perceived).

[11] NAL0019519 - Independent Project Analysis, Pacesetter Evaluation of the Muskrat Falls Generation Project and Island Link Transmission Project - September 2010
[12] NAL0019519 - Independent Project Analysis, Pacesetter Evaluation of the Muskrat Falls Generation Project and Island Link Transmission Project - September 2010
[13] NAL0019519 - Independent Project Analysis, Pacesetter Evaluation of the Muskrat Falls Generation Project and Island Link Transmission Project - September 2010
[14] NAL0017689 - Project Governance Plan - January 6, 2009
[15] NAL0017689 - Project Governance Plan - January 6, 2009
[16] Nalcor Energy – Response to Grant Thornton Question 1.3
[17] NAL0018156- Gateway Process – June 9, 2011
[18] NAL0017689 - Project Governance Plan - January 6, 2009

- We identified two versions of the IPR presentation dated August 31, 2012 for DG3. We compared both versions and identified differences between both IPR reports. An example of the differences noted is:

  Original – Final: *"the IPR team concurs with the expectations set by the LCP Project Execution and Risk Management Plans that adequate provisions for Management reserve and schedule reserve* ***be included in the Project Sanction costs and schedule****."*[19]

  Revised – Final: *"the IPR team concurs with the expectations set by the LCP Project Execution and Risk Management Plans that adequate provisions for Management Reserve and Schedule Reserve* ***be recognized in the Project Sanction decision making process****."*[20]

We note, that in this example the Original – Final version appears to suggest that the Project budget should include a provision for strategic risk. However, the revised version appears to only suggest an acknowledgement of the strategic risk. In response to our request, Nalcor has not identified any information concerning the differences between the two versions of this report.[21]

Decision Making Process

We reviewed the following publications and sources to determine whether the Gateway process followed by Nalcor was considered best practice:

1. Industrial Megaprojects – Concepts, Strategies and Practices for Success – Edward Merrow – Copyright 2011.
2. Westney Advisor (October 2008) – Are Stages and Gates Destroying Predictability? - The Unintended Consequences of Front End Loading.
3. Other Canadian provinces (i.e. Manitoba and British Columbia) – Need For and Alternatives to Resource Options.
4. The Navigant Report.

We have determined that the Decision Gate process followed by Nalcor is considered a best practice and is commonly used in mega projects globally across a variety of industries including its application to other developments across Canada.

[19] NAL0391751 – Independent Project Review Report – August 31, 2012
[20] NAL0391745 – Independent Project Review Report (Updated) – August 31, 2012
[21] Nalcor Energy - Response to Grant Thornton Question 8.4 – July 6, 2018

1.1 Energy Options

1.1.1 Background

The Nalcor P.U.B Submission noted that due to *"…the negative impacts associated with capacity and energy deficit..." "…NLH began to identify and review a broad range of alternatives for consideration as future sources of electricity."*[22]

This section describes Nalcor's decision making process to assess alternative power supply options. The power supply options available for generation are based on the region's supply of natural resources available to the utility.[23]

The following power supply options were outlined in the Nalcor P.U.B. Submission:[24]

- Nuclear
- Coal
- Biomass
- Solar
- Wave and Tidal
- Island Hydroelectric
- Labrador Hydroelectric
- Electricity Imports
- Natural Gas
- Liquefied Natural Gas
- Wind
- Simple Cycle Combustion Turbine
- Combined Cycle Combustion Turbine
- Oil-Fired Generation (Holyrood)

We understand that Nalcor employed a two phase approach to assessing the generation alternatives:[25]

Phase One

Phase One included benchmarking possible options against screening principles (discussed below). Nalcor has indicated that the *"screening principles were identified from engineering and industry experience."*[26] The following is a summary of screening principles and key considerations as provided in Nalcor's P.U.B Submission.[27]

[22] NAL0019056 - Nalcor's Submission to the Board of Commissioners of Public Utilities with respect to the Reference from the Lieutenant-Governor in Council on the Muskrat Falls Project – November 10, 2011
[23] NAL0018916 - Manitoba Hydro International: Report on Two Generation Expansion Alternatives for the Island Interconnected Electrical System, Volume 1: Summary of Reviews - January 2012
[24] NAL0019056 - Nalcor's Submission to the Board of Commissioners of Public Utilities with respect to the Reference from the Lieutenant-Governor in Council on the Muskrat Falls Project – November 10, 2011
[25] NAL0019056 - Nalcor's Submission to the Board of Commissioners of Public Utilities with respect to the Reference from the Lieutenant-Governor in Council on the Muskrat Falls Project – November 10, 2011
[26] Nalcor Energy - Response to Grant Thornton Question 8.6 – June 17, 2018
[27] NAL0019056 - Nalcor's Submission to the Board of Commissioners of Public Utilities with respect to the Reference from the Lieutenant-Governor in Council on the Muskrat Falls Project – November 10, 2011

Screening Principle	Key considerations
Security of supply and reliability	Nalcor indicated[28] that this was a primary principle in evaluating the energy supply investment. The principle requires: • The use of proven technologies to ensure they can meet the required expectations from security of supply, reliability and operational perspectives. • A high level of certainty that all elements of the plan can be permitted, constructed and integrated successfully with existing operations Nalcor determined that generation technologies which did not meet these two requirements should be excluded from further consideration.
Cost to ratepayers	Nalcor considers maintaining the least cost for ratepayers as a key objective of the company and as a result, this is a stated consideration in their business decisions, expansion plans and overall strategy.
Environmental considerations	Nalcor indicated that options were assessed in the context of adherence to any current environmental restrictions, as well as possible future legislation, due to the long term nature of any generation expansion.
Risk and uncertainty	Risk and uncertainty was expected to be considered throughout the decision making process.
Financial viability of non-regulated elements	Nalcor's consideration of the financial viability of the assessed alternatives in the context of the options ability to generate an adequate rate of return for shareholders. As well, Nalcor indicated that they also considered their ability to obtain debt financing for the project and their subsequent ability to meet debt repayment obligations.

Note: We requested supporting documentation that provides more detail into the screening principles referred to above. However, Nalcor indicated, *"a more detailed discussion of the principles, objectives or topics considered…is not available."*[29]

The following power supply options were excluded as possible sources of energy:

- Nuclear
- Natural gas
- Liquefied natural gas ("LNG")
- Coal
- Biomass
- Solar
- Wave/Tidal

[28] NAL0019056 - Nalcor's Submission to the Board of Commissioners of Public Utilities with respect to the Reference from the Lieutenant Governor in Council on the Muskrat Falls Project - November 10, 2011
[29] Nalcor Energy - Response to Grant Thornton Question 8.6 – June 17, 2018

1.1.2 Nuclear

The Electrical Power Control Act, 1994 Part I Declaration of Policy and Implementation Section 3(f) indicates, "*planning for future power supply of the province shall not include nuclear power*"[30]. In addition, this government policy is reaffirmed in the Energy Plan where is states *"No role is foreseen for nuclear generation in the province. Even if provincial legislation prohibiting nuclear generation were not in place, more cost-effective and flexible hydro alternatives are already available to us and are well understood."*[31]

The Navigant Report concluded that *"Nalcor appropriately excluded nuclear generation in both generation expansion alternatives because of provincial legislation, project capital costs and risk factors."*[32]

1.1.3 Natural Gas ("NG") / Liquefied Natural Gas ("LNG")

In 2001, Pan Maritime Kenny – IHS Energy Alliance ("Pan Maritime Kenny") reviewed the "Technical Feasibility of Offshore Natural Gas and Gas Liquid Development Based on a Submarine Pipeline Transportation System – Off Shore Newfoundland and Labrador." Their report was prepared for the Government of Newfoundland and Labrador. Pan Maritime Kenny noted that the *"...main objective of this study was to establish if the development of natural gas from the Jeanne d'Arc Basin via a marine pipeline was technically and economically feasible and under what conditions."*[33] Pan Maritime Kenny concluded that:

- *"Delivery of gas for domestic use for power generation, industrial, commercial, and residential is not economically feasible without integral development for delivery to Eastern Canada and the US. This is due to the small size of the potential domestic market and the resulting high unit cost of bringing the gas to shore combined with the cost of installing a gas pipeline from the Grand Banks to Come-by-Chance."*[34]

In the Nalcor P.U.B. Submission, Nalcor determined that natural gas from the Grand Banks of Newfoundland is not a viable option to meet the island of Newfoundland's electricity needs[35] due to the identified domestic market being too small to absorb the considerable project risks, capital investment and operating costs of a natural gas development.

The Navigant Report concluded that *"Nalcor appropriately excluded natural gas generation in both generation expansion alternatives because natural gas is not commercially available on the Island and there are, yet, no firm development plans to bring natural gas to the Island"*.[36] Navigant also concluded that Nalcor appropriately excluded LNG generation in both generation expansion alternatives because there was no clear economic advantage to using LNG given the required capital for LNG-related facilities, coupled with the linkage of long term LNG pricing to oil.[37]

As a result, Nalcor concluded that due to the lack of a confirmed development plan for Grand Banks natural gas, the small domestic requirement in comparison to the economic threshold for development, as well as the varying uses by operators, Nalcor screened out domestic natural gas as a supply option.

On February 13, 2012, Dr. Stephen E. Bruneau submitted "discussion points – Natural Gas for Island Electrical Generation" to the P.U.B. for consideration. In this document Dr. Bruneau concluded that *"Grand Banks (probably White Rose) gas is likely the cheapest source of long-term (30 years) dispatchable energy for island electricity generation if good faith bargaining were to take place. Dual-fuelling with oil storage on standby could provide supply security for a new thermal generating facility at or near Holyrood. Of considerable importance to note is the prospect for another fixed platform at or near White Rose. With prior arrangement, this facility may prove to be the ideal launching site for a pipeline to the Island. Many possibilities exist for gas export arrangements including third party ownership and operation of various parts*

[30] Electrical Power Control Act - 1994
[31] NAL0018682 – Government of Newfoundland and Labrador – Energy Plan (2007)
[32] NAL0018800 - Independent Supply Decision Review - September 14, 2011
[33] Pan Maritime Kenny - Technical Feasibility of Offshore Natural Gas and Gas Liquid Development Based on a Submarine Pipeline Transportation System - October 2001
[34] Pan Maritime Kenny - Technical Feasibility of Offshore Natural Gas and Gas Liquid Development Based on a Submarine Pipeline Transportation System – October 2001
[35] NAL0019056 - Nalcor's Submission to the Board of Commissioners of Public Utilities with respect to the Reference from the Lieutenant Governor in Council on the Muskrat Falls Project - November 10, 2011
[36] NAL0018800 - Independent Supply Decision Review - September 14, 2011
[37] NAL0018800 - Independent Supply Decision Review - September 14, 2011

of the gas compression and transmission system. The retirement of Holyrood and the construction of a new gas fired facility may also be a very attractive regulated business proposition for numerous private enterprises."[38]

Subsequently on March 28, 2012, Dr. Bruneau, hosted a moderated discussion session where he presented issues involved with bringing natural gas onshore. His presentation titled "*Grand Banks Natural Gas for Island Electric Generation*"[39] highlighted three objectives for the discussion as:

- *"to demonstrate that Grand Banks Natural gas is technically available and also economically compelling in the time frame and in quantities suitable for our domestic needs."*
- *"provide a discussion of the technical elements, costs and possible scenarios for natural gas delivery and use for domestic electricity generation."*
- *"to answer common questions, expose red herring and point out how natural gas can help meet our common goals."*

In addressing these objectives, Dr. Bruneau concluded the following:

- *"Natural Gas is available for domestic import now and for a long time into the future, but no plans or efforts have been made to access it."*
- *"Natural Gas is being produced at a rate that exceeds our domestic electrical needs – can sustain our requirements for a long time."*
- *"Natural Gas reserves and resources on the Grand Banks are in quantities that exceed domestic electrical requirements for the foreseeable future."*
- *"Capital costs are very low relative to the alternatives presently under consideration for domestic electricity supply."*
- *"The reason for excluding Natural Gas from the expansion alternatives considered by Navigant appears invalid."*
- *"There is a policy-mandated duty to the public to investigate the natural gas option – as described in the Energy Plan."*

Based on these findings Dr Bruneau recommended, *"an independent review of the natural gas-for-domestic-power option be required before a final decision is made (with regards to) committing the public to a 50 year binding agreement to Muskrat Falls."*

Subsequent to Dr Bruneau's commentary, the GNL engaged Ziff Energy Group ("Ziff") to review natural gas as a supply option. Ziff's report titled "Natural Gas as an Island Supply Option" dated October 30, 2012 concluded the following:

- *"Grand Banks pipeline supplied natural gas is not a viable replacement for the current oil-fired Holyrood electric generation facility. While natural gas is physically available offshore Newfoundland and Labrador, it is not available on commercially viable terms for power generation. Current surplus gas production is either injected for use in oil recovery, or stored for later use in oil recovery or for future monetization. Oil and gas companies have evaluated natural gas monetization opportunities and have yet to identify an economic project. The power generation demand on the Island is so small that any investment in offshore infrastructure (facilities, wells and pipeline) plus associated operating costs cannot produce the return(s) on capital required for oil and gas companies."*[40]

[38] Dr. Stephen E. Bruneau – Submission to PUB "discussion points – natural gas for island electrical generation" – February 13, 2012
[39] Dr. Stephen E. Bruneau - Grand Banks Natural Gas for Island Electric Generation - March 28, 2012
[40] NAL0018671 - Natural Gas as an Island Power Generation Option - October 30, 2012

- *"LNG supplied natural gas for power generation is not a viable alternative to the current oil-fired Holyrood generation of electricity. In order to address utility supply risks, LNG should be sourced under long term contracts which are predominantly oil-indexed. Oil-indexation suggests long term pricing at approximately 80 to 90% of World Oil Prices (Brent). Despite the abundance of shale gas in North America, oil indexation for LNG will be a sustaining commercial model going forward. The low and variable volumes of gas required to produce power at Holyrood are an economic barrier to securing long-term firm LNG Supply. The required investment in Regasification ("Regas") and storage infrastructure, when amortized over such low and variable volumes, renders LNG as an Island power generation option uneconomic. Full cycle LNG supply costs will likely be similar, or in excess of, the current oil-fired power generation at Holyrood and higher than the proposed Muskrat Falls Project."*[41]

As a final step in the analysis of natural gas as a supply option, the Newfoundland and Labrador Department of Natural Resources ("DNR") engaged Wood Mackenzie to review and comment on the analysis that was prepared by Ziff on a pipeline solution for Grand Banks natural gas. Wood Mackenzie's November 2012 report concluded *"Ziff's analysis and conclusions relative to natural gas as a fuel source for Newfoundland to be reasonable in regards to the use of natural gas produced in the White Rose fields. If anything, Wood Mackenzie's estimates of costs in this area would tend to be higher, rather than lower than those determined by Ziff. Additionally, we believe that the Government of Newfoundland may find it difficult to enter a contract for that gas that would make the producers interested in producing the gas for market due to the costs of production and the low level of requirements that Newfoundland will have for power generation."*[42]

1.1.4 Coal

Nalcor recognized that *"historically the benefits of coal-fired generation have been based on economics"* in Nalcor's P.U.B. Submission.[43] They go on to say that *"With an abundant supply of coal resources, the relative ease to transport the resource by rail and/or sea, and the relatively high energy content meant that significant energy potential could be harnessed at relatively low unit costs."*

However, Nalcor also noted that "*Because of uncertainty in costs and feasibility associated with meeting gazetted federal regulations, there is significant risk in pursuing coal-fired generation as a resource option. Carbon capture and storage technology (CCS) would be required for a coal-fired facility to achieve the proposed federal target. This unproven technology is still at the research and development phase and has not been deployed on a commercial scale. Saskatchewan has recently approved a $1.2 billion project to implement CCS demonstration project on the 110 MW Unit 3 of SaskPower's Boundary Dam thermal facility. Given the potential for GHG regulation and the uncertainty and cost associated with CCS coal fired generation was screened out as an alternative source for the Isolated Island alternative."*[44]

The Navigant Report concluded, *"Nalcor appropriately excluded coal-fired generation in both generation expansion alternatives because of its significant environmental risks."*[45]

1.1.5 Biomass (Wood)

Nalcor's P.U.B. Submission notes that *"Biomass energy is derived from many different types of recently living organic matter (feedstock). However, in the context of producing large-scale energy, it is likely that the focus would be on harvesting forestry products as fuel for the biomass generator. Biomass works similar to many other thermally-based generators in that wood or other biomass products are harvested, treated and then transported to the generation plant to be used in place of other solid fuels such as coal to generate*

[41] NAL0018671 - Natural Gas as an Island Power Generation Option - October 30, 2012
[42] NAL0018708 - Review of "Grand Banks Natural Gas As An Island Electric Generation Option" - November 2012
[43] NAL0019056 - Nalcor's Submission to the Board of Commissioners of Public Utilities with respect to the Reference from the Lieutenant-Governor in Council on the Muskrat Falls Project, November 10, 2011
[44] NAL0019056 - Nalcor's Submission to the Board of Commissioners of Public Utilities with respect to the Reference from the Lieutenant-Governor in Council on the Muskrat Falls Project - November 10, 2011
[45] NAL0018800 - Independent Supply Decision Review - September 14, 2011

heat. The heat is then used to produce steam. The steam is in turn fed into a turbine that turns a generator to produce electricity."[46]

Nalcor identified several benefits of using biomass as a power supply. These benefits have been summarized below: [47]

- "biomass is the low GHG production net of the harvesting and transportation operations"
- "biomass is a renewable energy source if forests are properly managed"
- "biomass could also provide increased markets for the province's forestry industry as any new plants would require significant feedstock"
- "biomass plants, which typically operate more efficiently at base load values can load-follow within certain ramp rates"

When assessing this alternative as a power supply option in Newfoundland and Labrador Nalcor noted that:

- "significant development of this industry would be required in order to facilitate the addition of a biomass generator"
- "…it is estimated that the Province may have capacity for electricity produced from wood and spent pulping liquor in the range of perhaps 100 GWh by leveraging the existing infrastructure. This estimate is not the upper limit of electricity production; the Province certainly has significant areas of forest, but the infrastructure (access roads, vehicles and skilled labour) to harvest sufficient biomass to produce more than the estimated 100 GWh does not likely exist"
- "Due to the requirement to harvest a large and steady supply of forestry products, manage and maintain the sustainability of the forest harvest, and transportation costs in getting the harvested material to the generation site, the unit costs for energy from biomass plants is usually much higher than other forms of energy."

As per Nalcor, *"While biomass and other co-generation alternatives, when economically feasible, will be considered as future supply alternatives, they are not considered to be appropriate replacements for large-scale generation requirements due to the significant costs and risks around securing significant supply of feedstock. On this basis, biomass was screened out as an Isolated Island supply alternative."*[48]

The Navigant Report concluded that *"Nalcor appropriately excluded biomass from both generation expansion alternatives because of the relatively limited biomass accessible through NL's existing forestry infrastructure."*[49]

1.1.6 Solar

In Nalcor's P.U.B. Submission discussed solar power as *"the conversion of sunlight into electricity*." In Nalcor's submission they note three concerns with using solar power as a generation source[50]:

- "Solar power is non-dispatchable; when the sun shines, the system has to take the power generated and when the sun is not shining, during the night, or during cloudy periods, other forms of generation have to be available for backup."
- "NLH's peak demand period typically occurs in the winter during the supper hour. At that time, output from solar power will be nil. Thus, solar power will not provide any capacity at time of peak."

[46] NAL0019056 -Nalcor's Submission to the Board of Commissioners of Public Utilities with respect to the Reference from the Lieutenant-Governor in Council on the Muskrat Falls Project - November 10, 2011
[47] NAL0019056 - Nalcor's Submission to the Board of Commissioners of Public Utilities with respect to the Reference from the Lieutenant-Governor in Council on the Muskrat Falls Project - November 10, 2011
[48] NAL0019056 - Nalcor's Submission to the Board of Commissioners of Public Utilities with respect to the Reference from the Lieutenant-Governor in Council on the Muskrat Falls Project - November 10, 2011
[49] NAL0018800 - Independent Supply Decision Review - September 14, 2011
[50] NAL0019056 - Nalcor's Submission to the Board of Commissioners of Public Utilities with respect to the Reference from the Lieutenant-Governor in Council on the Muskrat Falls Project - November 10, 2011

- "Newfoundland and Labrador has one of the lowest rates of solar insolation in Canada, which would result in a low capacity factor and higher unit costs. Even in areas where solar insolation is highest, unit costs for commercial solar energy production are amongst the highest of all generation sources."

Nalcor concluded that "The combination of high cost, lack of availability of power at peak times in winter, lack of dispatchability and the province's low insolation rates resulted in solar being screened out as an Isolated Island supply alternative."[51]

The Navigant Report concluded that "*Nalcor appropriately excluded solar photovoltaic ("PV") generation in both generation expansion alternatives because of Newfoundland's low insolation rates and the cost of power from solar PV installations."*[52]

1.1.7 Wave and Tidal

The Nalcor P.U.B. Submission noted that "*Wave energy technologies work by using the movement of ocean surface waves to generate electricity. Kinetic energy exists in the moving waves of the ocean. That energy can be used to power a turbine. One type of wave generator uses the up and down motion of the wave to power a piston, which moves up and down inside a cylinder. The movement of the piston is used to turn an electrical generator".* [53] Wave energy would be harnessed through the wave and tidal movements to generate kinetic energy which would then power turbines to generate electricity.

When assessing this alternative as a supply option Nalcor noted the following potential concerns with wave and tidal generation:

- "…ocean environment can be harsh on the equipment used in wave and tidal installations. As a result, the equipment used must be built robustly in order to contend with waves and salt water."
- "…wave and tidal generators can cost approximately three to four times more than wind turbines per megawatt"
- "…in order for a tidal generator to work well, a large variation in tidal levels is required. This limits the locations where tidal generation can be installed to produce large amounts of electricity in an efficient manner."

Nalcor concluded that despite some limited successes, neither tidal nor wave power has become a commercial mainstream source of renewable energy. Consequently, Newfoundland and Labrador Hydro ("NLH") screened out the use of wave and tidal power as an alternative supply option for the Isolated Island alternative.

The Navigant Report concluded that "*Nalcor appropriately excluded wave and tidal generation in both generation expansion alternatives because of its unproven commercial viability."*[54]

1.1.8 Simple Cycle Combustion Turbines ("CT")

Nalcor considered simple cycle combustion turbines as a power supply alternative in their energy portfolio. The Nalcor P.U.B. Submission noted that *"simple cycle combustion turbines are capable of producing large amounts of useful power for a relatively small size and weight."* Nalcor noted several benefits of CT's including long mechanical life, low maintenance cost and relatively low capital cost.[55]

However, Nalcor also noted that there are limitations associated with this alternative including high fuel costs, and low simple cycle efficiency. Nalcor noted that CTs are primarily deployed on the island system for system reliability and capacity support for peak demand.

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[51] NAL0019056 - Nalcor's Submission to the Board of Commissioners of Public Utilities with respect to the Reference from the Lieutenant-Governor in Council on the Muskrat Falls Project - November 10, 2011
[52] NAL0018800 - Independent Supply Decision Review - September 14, 2011
[53] NAL0019056 - Nalcor's Submission to the Board of Commissioners of Public Utilities with respect to the Reference from the Lieutenant-Governor in Council on the Muskrat Falls Project, November 10, 2011
[54] NAL0018800 - Independent Supply Decision Review - September 14, 2011
[55] NAL0019056 - Nalcor's Submission to the Board of Commissioners of Public Utilities with respect to the Reference from the Lieutenant-Governor in Council on the Muskrat Falls Project - November 10, 2011

Nalcor concluded that *"Combustion turbine technology is an integral part of the resource mix on the Isolated Island system today. CTs are applicable and necessary supply resource for both the Isolated Island alternative and the Interconnected Island alternative. Consequently, the combustion turbine technology was included in the generation expansion alternatives."*

1.1.9 Combined Cycle Combustion Turbines ("CCCT")

We understand that a combined cycle combustion turbine consists of a simple cycle combustion turbine, a heat recovery steam generator and a steam turbine generator.

The Nalcor P.U.B. Submission noted that *"one of the primary benefits of a CCCT plant is that it can be used as base load power generation. A CCCT generator is more efficient than either a stand-alone combustion turbine or steam turbine. A CCCT plant is essentially an electrical power plant in which combustion turbine and steam turbine technologies are used in combination to achieve greater efficiency than would be possible independently. This high fuel efficiency makes it possible for CCCTs to be competitive for intermediate or base load applications at relatively high price fuels."*[56]

However, Nalcor also noted limitations associated with this alternative including variations associated with fuel costs, and low simple cycle efficiency. Nalcor indicated that CCCTs are primarily deployed on the island system for system reliability and capacity support for peak demand.

Nalcor concluded that *"CCCTs are an applicable supply resource for both the Isolated Island alternative and the Interconnected Island alternative. Consequently, the combined cycle combustion turbine technology was included in the generation expansion alternatives."*

1.1.10 Wind

Wind energy was discussed throughout Nalcor P.U.B. Submission. Specifically, Nalcor defines wind energy as *"the process by which wind turbines convert the movement of wind into electricity."*[57]

Nalcor's submission outlines a number of benefits of wind energy including:

- *"Newfoundland and Labrador has an excellent wind resource"*
- *"wind energy is fueled by the wind, so it's a clean fuel source"*
- *"wind energy does not generate air pollution or produce atmospheric emissions"*[58]

However, Nalcor has also highlighted some drawbacks to the use of wind energy, including:

- *"Electricity generated from wind power can be highly variable at several different timescales: from hour to hour, daily, and seasonally,"*
- *'Wind power forecasting methods are used, but predictability of wind plant output remains low for short-term operation,"*
- *"Because instantaneous electrical generation and consumption must remain in balance to maintain grid stability and ensure the electricity is available when the customer needs it, this variability can present substantial challenges to incorporating large amounts of wind power into the Isolated System."*
- *"Good wind sites are often located in remote locations, far from places where the electricity is needed. Transmission lines must be built to bring the electricity from the wind farm to the places of high demand".*[59]

[56] NAL0019056 - Nalcor's Submission to the Board of Commissioners of Public Utilities with respect to the Reference from the Lieutenant-Governor in Council on the Muskrat Falls Project - November 10, 2011
[57] NAL0019056 - Nalcor's Submission to the Board of Commissioners of Public Utilities with respect to the Reference from the Lieutenant-Governor in Council on the Muskrat Falls Project - November 10, 2011
[58] NAL0019056 - Nalcor's Submission to the Board of Commissioners of Public Utilities with respect to the Reference from the Lieutenant-Governor in Council on the Muskrat Falls Project - November 10, 2011
[59] NAL0019056 - Nalcor's Submission to the Board of Commissioners of Public Utilities with respect to the Reference from the Lieutenant-Governor in Council on the Muskrat Falls Project - November 10, 2011

During their assessment of the use of wind energy within the island grid system, Nalcor references a report that was prepared by NLH's System Planning & System Operations team in October 2004, titled "*An Assessment of Limitations for Non-dispatchable Generation on the Newfoundland Island System*".[60] This report was prepared by NLH to *"define the scope of the opportunity for wind development on the Island of Newfoundland".*[61] This document focuses on two concerns with wind power:

1. *"the ability of wind generators to operate is contingent on…whether or not the wind is blowing…and therefore cannot be turned on at will"*
2. There are times when *"capacity can no longer be absorbed into the system without adverse technical and economic impacts"*

NLH's analysis concluded that up to 80 MW of wind generation could be incorporated into the system.[62] Nalcor relied on this limit in their 2011 submission to the P.U.B. but they noted that *"as load grows, the Isolated Island system should be able to accommodate additional wind generation. It has been suggested that the system should be able to accommodate an additional 100 MW of wind in the 2025 timeframe and a further 100 MW around 2035. NLH will study this prior to Decision Gate 3 (DG3).*[63]

Based on the information available to Nalcor at the time of their submission to the P.U.B. they concluded that *"the use of a large-scale wind farm to replace the firm continuous supply capability of the Holyrood generating plant is not operationally feasible and therefore was not considered in the generation expansion analysis."*[64] Nalcor goes on to say "*Wind power has a place in the electricity generation mix on the island and due to its low environmental footprint, it will be incorporated whenever economically viable. However, technical and operational considerations limit the amount of wind generation that can be operated on the system".*[65]

Subsequently, Nalcor engaged Hatch to perform *"a study to assess how much additional non-dispatchable wind generation can be added, economically and technically, to the Island of Newfoundland's power system."*[66] The results of this study are outlined in the *"Report for Wind Integration Study – Isolated Island"* prepared as of August 7, 2012. Hatch concluded that *"for an isolated Newfoundland power system, increased wind generation will be used to decrease the use of thermal generation as much as possible without affecting voltage and frequency support, and without unduly increasing spill and causing significantly less efficient dispatch of the hydro generating units".*[67] Based on their analysis, Hatch recommended that *"a maximum of 300 MW during the extreme light load conditions for 2035 to prevent violation of stability criteria. Similarly, the wind generation penetration level should not exceed 500 MW during the peak load conditions to avoid transmission line thermal overloads".*[68]

In addition to the analysis performed for Nalcor and their external consultants, the Government of Newfoundland and Labrador engaged MHI to provide a review, opinion and commentary on the reasonableness of the reports provided by Nalcor Energy on the subject of wind in the Isolated Island Option.[69] The results of their analysis is outlined in MHI's report "Review of the Wind Study for the Isolated Island of Newfoundland" dated October 2012. The goals of MHI's report were:

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[60] NAL0018880 - An Assessment of Limitations for Non-dispatchable Generation on the Newfoundland Island System – October 2004
[61] NAL0018880 - An Assessment of Limitations for Non-dispatchable Generation on the Newfoundland Island System – October 2004
[62] NAL0018880 - An Assessment of Limitations for Non-dispatchable Generation on the Newfoundland Island System – October 2004
[63] NAL0019056 - Nalcor's Submission to the Board of Commissioners of Public Utilities with respect to the Reference from the Lieutenant-Governor in Council on the Muskrat Falls Project - November 10, 2011
[64] NAL0019056 - Nalcor's Submission to the Board of Commissioners of Public Utilities with respect to the Reference from the Lieutenant-Governor in Council on the Muskrat Falls Project - November 10, 2011
[65] NAL0019056 - Nalcor's Submission to the Board of Commissioners of Public Utilities with respect to the Reference from the Lieutenant-Governor in Council on the Muskrat Falls Project - November 10, 2011
[66] NAL0018669 – Report for Wind Integration Study – Isolated Island – August 7, 2012
[67] NAL0018669 – Report for Wind Integration Study – Isolated Island – August 7, 2012
[68] NAL0018669 – Report for Wind Integration Study – Isolated Island – August 7, 2012
[69] NAL0018692 - Review of the Wind Study for the Isolated Island of Newfoundland - October 2012

1 *1 "Complete a due diligence review of the studies provided by Nalcor to determine if the study goals have*
2 *been met.*

3 *2 Utilizing information provided by Nalcor, and other literature as appropriate, provide a narrative that*
4 *addresses the following questions: "In an isolated island scenario, can sufficient wind be developed to*
5 *replace the Holyrood Thermal Generating Station and meet future demands? Is this a technically feasible*
6 *and economic alternative to Muskrat Falls and the Labrador Island Link?"*

7 MHI concluded that: [70]

8 – *"Two reports on the development of wind for the Isolated Island of Newfoundland were reviewed;*
9 *Hatch's Wind Integration Study – Isolated Island and Nalcor's Wind Integration – Voltage Regulation*
10 *and Stability Analysis. Both reports are technically sound and meet their study goals... In MHI's*
11 *opinion, Nalcor has incorporated the maximum amount of wind generation in the Isolated Island*
12 *Option based on the result of these studies."*

13 – *"Based on these screening level study findings (at an AACE Class 4 estimate), and the inherent*
14 *technical risks in such a massive wind development, MHI does not recommend that the wind options*
15 *beyond a 10% penetration level, the level recommended by the 2012 Hatch Study and adopted by*
16 *Nalcor for the Isolated Island Option, be pursued at this time."*

17 – *"Investment in the Muskrat Falls Interconnected option provides a firm supply, and an opportunity to*
18 *monetize the excess energy once another interconnection is made. The wind power scenarios do not*
19 *provide the same value for the $11.86 or $17.43 billion costed over the study period. One must note*
20 *that the wind scenarios theorized are still largely a thermal generation resource plan once the*
21 *Holyrood Thermal Generation Station is replaced."*

22 – *"MHI finds that large scale wind development, as a replacement to Holyrood Thermal Generation*
23 *Station, is not a least cost option and does not represent a good utility practice at this time."*

24 1.1.11 Findings and Observations

25 – Nalcor's decision to eliminate nuclear energy as a power supply option was based on the conclusion
26 of their external consultants review and the legislative environment at the time of their decision.
27 Nothing has come to our attention which would suggest this decision was unreasonable at the time
28 the decision was made.

29 – Nalcor's decision to eliminate NG and LNG as a power supply option was based on an expert review
30 dated from 2001 (10 years old at the time of their submission to the P.U.B.). At the time of the P.U.B.
31 review, there were public submissions which opposed this conclusion. The GNL engaged external
32 experts that supported their decision. Based on our review nothing has come to our attention which
33 would suggest that excluding natural gas and LNG was unreasonable.

34 – Nalcor's decision to eliminate coal as a power supply option was based on the conclusion of their
35 external consultants review and the uncertainty of future environmental legislation at the time of their
36 decision. Nothing has come to our attention which would suggest this decision was unreasonable at
37 the time the decision was made.

38 – Nalcor's decision to eliminate biomass as a power supply option was based on the conclusion of their
39 external consultants review and the status of the forestry industry in Newfoundland at the time of their
40 decision. Nothing has come to our attention which would suggest this decision was unreasonable at
41 the time the decision was made.

42 – Nalcor's decision to eliminate solar generation as a power supply option was based on the conclusion
43 of their external consultants review and the solar insulation rates in Newfoundland. Nothing has come

[70] NAL0018692 - Review of the Wind Study for the Isolated Island of Newfoundland - October 2012

to our attention which would suggest this decision was unreasonable at the time the decision was made.

- Nalcor's decision to eliminate wave and tidal generation as a power supply option was based on the conclusion of their external consultants review and the maturity of wave and tidal generation technology. Nothing has come to our attention which would suggest this decision was unreasonable at the time the decision was made.
- During our review, nothing has come to our attention which would suggest that Nalcor's decision to include simple cycle turbines as an alternative in their system generation planning was unreasonable at the time the decision was made.
- During our review, nothing has come to our attention which would suggest that Nalcor's decision to include CCCT's, as an alternative in their system generation planning was unreasonable at the time the decision was made.
- Nalcor's decision to eliminate the use of a large-scale wind farm to replace the Holyrood generating plant is consistent with their underlying analysis and supported by analysis from third party experts. Subsequent to the decision, the GNL engaged an external expert to review the matter. They concluded that large scale wind development, as a re-placement to Holyrood Thermal Generation Station, is not a least cost option and does not represent a good utility practice at this time. Nothing has come to our attention which would suggest Nalcor's treatment of wind as an alternative energy source was unreasonable at the time of sanction.

1.1.12 Phase Two

Once an alternative successfully passed the phase one screening principles we understand that Nalcor entered the second phase of their analysis. During the phase two screening process Nalcor enters the power supply alternatives into Strategist with key inputs such as load forecast, capital cost estimates etc. Strategist develops generation expansion plan scenarios which are then used in Nalcor's expansion decision making. A more detailed discussion of Strategist and the CPW analysis is included later in this report.

1.1.13 DG2 - 2010 Financial Analysis

The November 16, 2010 board support package for the Nalcor Energy Board of Directors includes a slide presentation titled "Island Energy Supply and Lower Churchill – Option Evaluation and Recommendation". This document outlined five alternatives to supply energy to the Island as summarized below:[71]

1. **Isolated Island Option** – this alternative includes a phased approach using wind, island hydroelectric, combustion turbines and environmental upgrades to Holyrood Thermal Generating Station.
2. **LCP – Gull Island** – this alternative includes an initial investment in a combustion turbine, the construction of 2,250 MW Gull Island Generation Station, construction of a 900MW HVdc transmission link to the island, and the shutdown of the Holyrood Thermal Generating Station.
3. **LCP – Muskrat Falls** - this alternative includes an initial investment in a combustion turbine, the construction of 824 MW Muskrat Falls Generation Station, construction of a 900MW HVdc transmission link to the island, and the shutdown of the Holyrood Thermal Generating Station.
4. **Imports from/via Hydro Quebec at Churchill Falls** – this alternative includes an initial investment in a combustion turbine, the construction of a 900MW HVdc transmission link to the island, and the shutdown of the Holyrood Thermal Generating Station. There is no investment in additional generation, as Nalcor would purchase power from or via Hydro Quebec at Churchill Falls for market prices.
5. **Imports from New England Independent System Operator (NEISO) via 900MW Maritime Link** – this alternative includes an initial investment in a combustion turbine, the construction of a 900MW

[71] NAL0019237 – Board Package to 33rd Board Meeting, Island Energy Supply and Lower Churchill – Option Evaluation and Recommendation – November 16, 2010

transmission link to the Maritimes, and the shutdown of the Holyrood Thermal Generating Station. There is no investment in additional generation, as Nalcor would purchase power through Nova Scotia or New Brunswick at the regional market price.

The following table summarizes the information presented to the Board on each of the previously mentioned alternatives.

	Isolated Island	LCP Gull Island	LCP Muskrat Falls	Imports from/via Hydro Quebec	Import from NEISO via ML
CPW of revenue requirement ($M)	$12,272[72]	$10,114	$10,114[73]	$11,559[74]	$11,657[75]
Capex ($M 2010)	$8,074	$6,582	$6,582	$6,945	$6,748
Risks	Fuel cost Environmental	Environmental approval/schedule Capital cost control Schedule Heavy spill over project life	Environmental approval/schedule Capital cost control Schedule	Ability to secure long-term firm supply Market price volatility	Project execution for complex multi-jurisdictional link Market price volatility
Reliability	No interconnection to North American Grid	Interconnected to the North American Grid via Churchill Falls	Interconnected to the North American Grid via Churchill Falls	Interconnected to the North American Grid however, continuity of supply not assured	Interconnected to the North American Grid however, continuity of supply not assured
Rate of return on non regulated	N/A	5.7% IRR assuming no monetization of spill	8.4% IRR assuming no monetization of spill	N/A	N/A

Summary of information presented in NAL0019237 – Board Package to 33rd Board Meeting, Island Energy Supply and Lower Churchill – Option Evaluation and Recommendation – November 16, 2010

(1) *The above chart shows the cost of Gull Island and Muskrat Falls were the same based on NAL0019237. However we understand that the actual costs to develop Gull Island would have been greater than the cost estimate for Muskrat Falls due to the scale of the project.*

[72] Nalcor Energy - Response to Grant Thornton Question 8.10 – OutputComparison.PLF10Init.Base.Oct27v2.xls – July 10, 2018

[73] Nalcor Energy - Response to Grant Thornton Question 8.10 – OutputComparison.PLF10Init.Base.Oct27v2.xls – July 10, 2018

[74] Nalcor Energy - Response to Grant Thornton Question 8.10 – July 10, 2018

[75] Nalcor Energy - Response to Grant Thornton Question 8.11 – July 10, 2018

In addition, the Board was provided with a summary of the five alternatives comparing each of them to the screening principles, as follows:

Criterion	Isolated Island	LCP - Gull Island	LCP-Muskrat Falls	Imports from/via HQ	Imports from NEISO via ML
Reliability	No interconnection to NA grid	Interconnected	Interconnected	Assurance of long term firm supply?	Assurance of long term firm supply?
Cost to Ratepayers	Reference Case	Assumed same as Muskrat; would be unaffordable if full costs recovered	Better than reference case long term; similar short term	Higher than LCP-Muskrat	Higher than LCP-Muskrat
Environment	Petroleum Based	Renewable to maximum extent	Renewable to maximum extent	Ultimate power source unknown	Ultimate power source unknown
Risk and uncertainty	Fuel price Enviro costs	Heavy spill over project life	Schedule and approvals; capital cost control	No assurance of firm supply; price volatility	No assurance of firm supply; price volatility
Financial viability of non-regulated elements	N/A	IRR with spill less than cost of shareholder borrowing; debt financing problematic	IRR exceeds cost of shareholder's associated borrowing	N/A	N/A

The above table is an excerpt from NAL0019237 – Board Package to 33rd Board Meeting dated November 16, 2010 – Island Energy Supply and Lower Churchill – Option Evaluation and Recommendation – Page 99

Based on this analysis referred to above Nalcor concluded that proceeding with LCP – Muskrat Falls is the preferred option, supported by the following:

- Strong reliability profile
- A solution internal to NL – no complications with external jurisdictions
- Lowest long term cost to ratepayer
- Environmentally sound
- Lower supply and price risk than import scenarios; no exposure to fuel price volatility as island isolated
- Potential for attractive shareholder returns if export volume can be achieved, but viable if not
- Advances objectives of the Energy Plan[76]

1.1.14 Isolated Island Option

In Nalcor's P.U.B. Submission, it noted that the Isolated Island Option involves the further development of island hydroelectric facilities, additional wind supply and a combination of replacement capital for existing

[76] NAL0019237 – Board Package to 33rd Board Meeting – Island Energy Supply and Lower Churchill – Option Evaluation and Recommendation – November 16, 2010

thermal facilities and the construction of new thermal resources utilizing fossil fuels purchased in the global oil markets.

The expansion plan for the Isolated Island Option would include the development of Portland Creek, Island Pond and Round Pond as additional hydro developments, wind generation within constraints, and both simple and combined cycle combustion turbines. An assessment of the CPW of this option is provided in this report.

1.1.15 Interconnected Island Option

Interconnected Island Option involves the development of a hydroelectric facility on the Lower Churchill River and a transmission link to the Island of Newfoundland and Labrador. In 2007, "*LCP included both generation sites at Gull Island and Muskrat Falls, as well as the transmission system required to enable power export to the Island, Quebec and Maritimes."*[77] The scope of the LCP included a focus on developing Gull Island first with Muskrat Falls to be developed as phase two of the LCP.

1.1.16 Gull Island ("GI")

In the Nalcor P.U.B. Submission Gull Island is discussed as follows:

"Gull Island is a 2,250 MW hydroelectric generation project on the Churchill River with an average annual energy capability of 11.9 TWh. Located 225 kilometers downstream from the existing Churchill Falls power plant, Gull Island has been extensively studied over the years and the engineering work completed has led to a high level of confidence in the planned design and optimization of the facility. Gull Island is the larger of the two Lower Churchill sites. While offering more favourable economies of scale than Muskrat Falls, and therefore a lower unit cost per MWh of production, if all of the output was assumed sold or used, Gull Island requires significantly greater capital investment. The scale of Gull Island output creates a requirement to either negotiate with neighbouring utilities for export contracts, attract investments in energy intensive industries, or to participate directly in regional wholesale markets to attain the full utilization unit cost. If such opportunities do not exist, and island supply is the only available market, then the total cost for Gull Island has to be spread over a smaller block of utilized energy. This makes the actual unit cost of Gull Island greater than Muskrat Falls."

Nalcor concluded:

"As a result of the high unit cost of energy without external sales or other new usage compared to Muskrat Falls, the absence of firm transmission access to export markets at this time and the difficulty of arranging financing in such an environment, Gull Island did not advance past the Phase 1 screening of alternatives."

The GNL Department of Natural Resources also considered the public's question "Why Not Develop Gull Island First?" The results of their analysis was published it their report "Why Not Develop Gull Island First?" in November of 2012. This report concluded that "*the Gull Island development has not proceeded to date because of the inability to obtain transmission access across Quebec. The Provincial Government plans to develop Gull Island, but only if Newfoundland and Labrador is the principal beneficiary of development – not another jurisdiction. Without transmission access to export markets, it is not economically viable to develop Gull Island. Higher than forecast electricity demand in Newfoundland and Labrador would improve the prospects for development, but external markets remain critical for the project."*[78]

Nothing has come to our attention which would suggest that Nalcor's decision to eliminate the development of Gull Island in Phase one of their analysis was inappropriate at the time the sanction decision was made.

[77] Muskrat Falls Project – Summary of Pre-Sanction – Briefing Note as Requested by Nalcor Legal Counsel McInnes-Cooper
[78] NAL0018695 – Gull Island: Why Not Develop Gull Island First – November 2012

1.1.17 Muskrat Falls ("MF")

During 2010, the scope of the LCP changed with the development of Muskrat Falls hydroelectric generating facility and the Labrador Island Transmission Link referred to as the first phase of the LCP. At this time, the development of Gull Island was deferred. Nalcor would still have the option of developing a hydroelectric generating facility at the Gull Island site but this would be beyond the scope of the decision to sanction the development of Muskrat Falls. This option would utilize the Holyrood Thermal Generating Station until 2021 at which following that it would not be required to maintain operation.[79]

Throughout our report we reference the term "Interconnected Island Option". In the context of Nalcor's December 2012 sanction decision the term Interconnected Island Option refers to the development of the Muskrat Falls Generation Facility coupled with the development of a Labrador-Island Link and the development of transmission assets from Muskrat Falls to Churchill Falls.

1.1.18 Electricity Imports

Nalcor considered electricity imports as an alternative to supply the power needs of the province prior to Muskrat Falls being sanctioned. This alternative included two potential sources.

1) Imports from/via Hydro Quebec
2) Imports from/via New England Independent System Operators

Both alternatives are addressed in the November 16, 2010 Nalcor board support package and revisited in Nalcor's submission to the PUB in November 2011. In these documents Nalcor considers the following matters:

- **Price volatility** – Nalcor determined that there is a strong correlation between electricity market prices and natural gas prices which are exposed to volatility;
- **Security of supply** – Nalcor noted that at the time of their analysis "plant retirements and/or de-rating across the region have implications for the availability and price of supply and are risks which are introduced as a result of relying on imports as a long-term supply source to the province"; and
- **Potential market structure** – Nalcor indicated that the process of transmitting power from the market to an external customer is complicated as there were no long-term physical transmission rights in place.

Based on their analysis Nalcor concluded *"as a result of the risks outlined on price volatility, security of long-term supply, and transmission impediments, the reliance on electricity imports as a long-term supply option for the island was not considered further following phase 1 screening".*[80]

In addition to Nalcor's analysis the GNL also considered electricity imports as an alternative to developing the province's resources to meet its electricity demand and displace thermal production at the Holyrood Generating Station. The results of their analysis was published by the Department of Natural Resources in "Electricity Imports" published on July 2012.[81] This document outlined several findings as follows:

- *"Importing power to meet the province's long-term electricity needs is not a viable alternative;*
- *There are significant issues related to: insufficient transmission capacity in New England/Maritimes; lack of long-term transmission rights in New England and New York markets; and reliability concerns;*
- *There is a concern about security of supply for both the Maritimes and the New England and New York markets;*

[79] NAL0019056 - Nalcor's Submission to the Board of Commissioners of Public Utilities with respect to the Reference from the Lieutenant-Governor in Council on the Muskrat Falls Project - November 10, 2011
[80] NAL0019056 - Nalcor's Submission to the Board of Commissioners of Public Utilities with respect to the Reference from the Lieutenant-Governor in Council on the Muskrat Falls Project - November 10, 2011
[81] Department of Natural Resources – Electricity Imports – July 2012

- *As electricity prices in both New England and New York are historically tied to natural gas prices, imported electricity from either market would be subject to price volatility;*
- *In addition to paying the market price for the electricity, other costs would be factored in to the final price including transmission tariffs and a premium to secure a long-term contract;*
- *As compared to the Muskrat Falls alternative, Nalcor estimates that the QC import option is $1.4 billion more expensive, and the Maritime import option is $1.5 billion more expensive; and*
- *Importing electricity from another jurisdiction would provide limited benefits to the people of the province in terms of employment, income and business opportunities; particularly when compared with the Muskrat Falls alternative."*

During the P.U.B. Muskrat Falls Review Nalcor noted that it *"…did not enter into discussions with Hydro Quebec for long term electricity supply …"*[82] During our interviews with Nalcor executives it was confirmed that there were no formal procedures initiated with Hydro Quebec.

We recognize that Nalcor completed an analysis of electricity imports as a supply option. However, we have noted that Nalcor made assumptions regarding the purchase price of power without engaging in formal discussions with Hydro Quebec.

1.1.19 Other Options Considered

Nalcor also considered two options that were not included in the November 16, 2010 board support package.

1.1.20 Deferred Churchill Falls

Another option considered by Nalcor was the *"continuation of Holyrood operations and additional thermal generation as required for another three decades, and then to commission a transmission interconnection between Labrador and the island to avail of electricity production from the Churchill Falls hydroelectric generating facility in 2041 when the current long-term supply contract with Hydro Quebec terminates."*

Nalcor's P.U.B. Submission noted that this option did not advance beyond phase one screening for several reasons including:

1) uncertainty around availability of supply from Churchill Falls in 2041 because of the difficulty in determining the environmental and policy frameworks that will be in place 30+ years out;
2) significant risk associated with maintaining reliable supply through continued life extension measures for Holyrood generating station through to 2041;
3) deferral of the LIL would result in significantly higher rates for island consumers between now and 2041. This would not provide rate stability to island consumers as rates would be tied to highly volatile fossil fuel prices for the first 30+ years of the study period;
4) customers will remain dependent on fossil fuel generation for the first 30+ years of the study resulting in continued and increasing greenhouse gas emissions; and
5) the prospect of requiring additional investment to extend Holyrood's service beyond what was contemplated increases the probability that this option will be more expensive than projected.

We note that Nalcor's submission to the P.U.B., summarized above, is contrary to NSUARB's findings related to availability of supply.

> **Nalcor Submission:** *"uncertainty around guaranteeing the availability of supply from Churchill Falls in 2041 because it is difficult to determine the environmental and policy frameworks that will be in place 30+ years out"*

[82] Nalcor Energy - Response to CA/KPR-Nalcor-32 – Muskrat Falls Review

> **2013 NSUARB 154 – MO5419:** *"while legitimate questions remain about the availability of Market-priced Energy from Nalcor over the first 24 years of the Maritime Link, the evidence clearly shows that there should be no shortage of Market-priced Energy when the Churchill Falls arrangement with Hydro Quebec comes to a conclusion in 2041."*

Subsequent to Nalcor's decision not to advance the deferral of the LCP beyond phase one screening, the GNL Department of Natural Resources released "Upper Churchill: Can we wait until 2041?"[83] in November 2012. This report concluded that the power contract between NL and Hydro Quebec expires in 2041. At that time the province will obtain much more control over Upper Churchill power than currently exists. However, DNR highlights that Upper Churchill power is not exclusively owned by GNL. Consequently GNL may not have control over the resource. DNR concludes that there will be no free power available to the province. In addition DNR concludes that there will be limited rights to recall power after the power contract expires. DNR's position was that waiting until 2041 is not a viable alternative for several reasons:

- Maintaining the isolated Island system until that time, followed by the construction of a transmission link with Labrador, is more expensive than developing Muskrat Falls;
- There is also considerable risk and uncertainty regarding security of supply and reliability, the cost to ratepayers, and environmental compliance;
- Deferring the project also means deferring the province's ability to fully capitalize on the value of its tremendous energy resources; and
- Deferring the Muskrat Falls development represents a more costly approach to supplying power and adds a layer of cost and uncertainty as power for domestic customers will be tied to fossil fuel prices as well as the ability to extend the life of the Holyrood Generating Station to provide reliable power within potential future GHG regulatory guidelines.

The overall conclusion of the DNR analysis was that "waiting for available Upper Churchill power in 2041 is not a practical, economical, or sensible alternative to Muskrat Falls."

Nalcor's decision to eliminate the deferred 2041 option was supported in part by a rationale which was inconsistent with a finding of the NSUARB in relation to the ML portion of the Muskrat Falls Project.

1.1.21 Recall Power

In Nalcor's P.U.B. Submission they state that under the existing power contract between Hydro Quebec ("HQ") and Churchill Falls (Labrador) Corporation ("CFLCo"), there is a provision for a 300 MW block of power which can be recalled for use in Labrador. The 300 MW block is sold to NLH in its entirety. NLH meets the needs of its customers in Labrador first and then sells any surplus energy into export markets. This explanation is supported by the GNL Department of Natural Resources "Upper Churchill: Can we wait until 2041?" report also discusses the concept of a recall block of power available from Upper Churchill.

In 2010, Nalcor indicated, "approximately 38 percent of the energy available under the 300 MW recall contract was sold in Labrador, with the unused balance being sold into short term export markets. On average in the winter almost 220 MW of power is used to meet demand in Labrador. With only 80 MW of recall power available in the winter, there is insufficient firm capacity and energy available to meet the island's electricity needs and to displace the Holyrood Plant, which generates almost 500 MW at the time of highest (winter) need for the province.[84] Because of the insufficient firm capacity, Nalcor screened the recall block of power out of their options to displace Holyrood.

Nothing has come to our attention which would suggest that Nalcor's decision to eliminate the recall block of power from their options to address the forecasted energy shortfall was inappropriate at the time the sanction decision was made.

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[83] NAL0018694 – Upper Churchill: Can we wait until 2041? - November 2012
[84] NAL0019056 - Nalcor's Submission to the Board of Commissioners of Public Utilities with respect to the Reference from the Lieutenant-Governor in Council on the Muskrat Falls Project - November 10, 2011

1.2 Planning Load Forecast Methodology and System Generation

1.2.1 Background – Load Forecasting

Planning load forecast ("PLF") is the process of the utility's system planning department to project the energy requirements and electricity demands for Newfoundland and Labrador's future periods. [85]

The first step in the planning process was to identify the island's electricity requirements and energy demands. NLH develops a 20 year load forecast on an annual basis. The forecast is used by NLH's system planners to ensure sufficient generation resources are available to reliably meet consumers' energy requirements.[86]

Energy requirements and electricity demands for the system are comprised of industrial load and utility load, which includes domestic and general service customers on the island. The industrial load forecast is developed with direct input from the customers, whereas the domestic and general service customer loads are based on projected modelling (i.e. econometric). [87]

NLH's load forecasting considered the following data inputs: [88]

- Macro-economic forecast provided by the GNL Department of Finance which included:
  - Gross domestic product;
  - Personal income levels;
  - New housing starts; and
  - Population growth.
- Oil production from Hebron beginning in 2017 to 2030
- Corner Brook Pulp & Paper ("CBPP") and North Atlantic Refining continuing as going concerns
- New start-ups (i.e. Vale starting in 2013)
- Other factors (i.e. weather, efficiency gains and historical use from late 1960s)

Nalcor's 2012 PLF's were for 56 years.[89] The load forecast subsequent to the 20th year was estimated using the last five years of the 20 year forecast. The extended forecast (an additional 36 years) was selected to coincide with the estimated service life of the Labrador-Island Link transmission line. No additional or reduction of industrial customers was considered in the forecast. [90]

[85] NAL0019056 - Nalcor's Submission to the Board of Commissioners of Public Utilities with respect to the Reference from the Lieutenant-Governor in Council on the Muskrat Falls Project - November 10, 2011
[86] NAL0018957 - Nalcor's Final Submission to the Board of Commissioners of Public utilities with respect to the reference from the Lieutenant-Governor In Council on the Muskrat Falls Project - March 2, 2012
[87] NAL0019056 - Nalcor's Submission to the Board of Commissioners of Public Utilities with respect to the Reference from the Lieutenant-Governor in Council on the Muskrat Falls Project - November 10, 2011
[88] NAL0019056 - Nalcor's Submission to the Board of Commissioners of Public Utilities with respect to the Reference from the Lieutenant-Governor in Council on the Muskrat Falls Project - November 10, 2011
[89] NAL0018691 – Review of Muskrat Falls and Labrador Island HVdc Link and the Isolated Island Options – October 2012
[90] NAL0019056 - Nalcor's Submission to the Board of Commissioners of Public Utilities with respect to the Reference from the Lieutenant-Governor in Council on the Muskrat Falls Project - November 10, 2011

We noted that both MHI and Navigant reported on the 2010 Planning Load Forecast. Findings by both Navigant and MHI are discussed further below. We noted that MHI commented on the 2012 Planning Load Forecast in the MHI October 2012 Report. In the 2012 report MHI concluded that both the Interconnected and Isolated Island load forecasts were considered to be well founded and appropriate as an input into the DG3 process.[91]

The summary conclusion by Navigant was that Nalcor's load forecast methodology was consistent with generally accepted utility practice and the base forecast for demand and energy growth was considered reasonable.

1.2.2 Findings and Observations

Methodology and Process

The MHI January 2012 Report stated that best utility practices would incorporate a combination of regression and end-use modelling techniques into the forecasting process for domestic customers, so that electricity growth can be quantified for all major domestic end-use of electricity.[92]

End-use modelling is determining energy needs based on detailed customer billing, survey analysis, and calculated using a bottom up approach, meaning that the forecast is an aggregate of the energy associated with each of the major domestic end-use (i.e.: electric space heating, dishwasher).[93]

MHI noted that the domestic forecast methodology implemented by Nalcor is acceptable in practice, but not best utility practice for this sector[94]. According to MHI, best utility practice would incorporate end-use methodology for the forecasting process for this sector, but increased accuracy is not guaranteed because any forecast is dependent on the accuracy of the assumptions on which it is based. MHI noted that other jurisdictions also applied a combination of regression and end-use modelling including Ontario, Manitoba and BC.

The Navigant report did not explicitly address the domestic customer methodology but concluded that Nalcor's forecasting methodology is consistent with generally accepted utility practice and the base forecast for demand and energy growth being reasonable during DG2[95].

During the DG3 process, Nalcor continued to apply the same methodology applied in DG2. MHI made no comments regarding the methodology used for domestic forecasting.[96]

1.3 Nalcor's Assumptions

1.3.1 Domestic Customers

During DG2 MHI stated that best utility practices would incorporate a combination of regression and end-use modelling techniques in forecasting domestic customer load. According to MHI end-use modeling would have allowed Nalcor to:[97]

- Quantify load growth by end-use;
- Quantify energy-efficiency by end-use;
- Incorporate new end-uses;

[91] Nalcor Energy - Response to Grant Thornton Question 5.3
[92] NAL0018917 - Manitoba Hydro International: Report on Two Generation Expansion Alternatives for the Island Interconnected Electrical System, Volume 2: Studies - January 2012
[93] NAL0018917 - Manitoba Hydro International: Report on Two Generation Expansion Alternatives for the Island Interconnected Electrical System, Volume 2: Studies - January 2012
[94] NAL0018916 - Manitoba Hydro International: Report on Two Generation Expansion Alternatives for the Island Interconnected Electrical System, Volume 1: Summary of Reviews - January 2012
[95] NAL0018800 – Independent Supply Decision Review, Navigant Consulting Ltd. - September 14, 2011
[96] NAL0018691 – Manitoba Hydro International – Review of the Muskrat Falls & Labrador Island HVAC Link and the Isolated Island Options - October 2012
[97] NAL0018917 - Manitoba Hydro International: Report on Two Generation Expansion Alternatives for the Island Interconnected Electrical System, Volume 2: Studies - January 2012

- Improve the design of conservation demand programs; and
- Improve the defensibility of the load forecasting process.

The P.U.B. Report to Government stated it is possible that end-use modeling would be of benefit in relation to some of the concerns that were noted during the review related to the potential impacts of conservation and demand management programs.[98]

In addition, the P.U.B. stated that "*Given that end-use modeling is best practice and the current model appears to have an inherent bias, it seems advisable to adopt end-use modeling before making a determination in relation to a large incremental increase in capacity such as the Interconnected Option."*[99]

In P.U.B.-NLH-058[100] Nalcor noted that end-use modeling techniques were attempted in the early 1990s but stopped as it was difficult to resource, had significant level of judgement, Newfoundland Power ("NP") would need to be involved for the process given their customer base, and there are operating cost considerations. NLH chose to discontinue adopting an end-use forecasting approach and instead continue with the econometric approach.

Two post Sanction reviews completed by Ventyx in 2014[101] and Power Advisory LCC[102] in 2015 concluded that there was not a clear justification for NLH to adopt an end-use forecasting system. Based on Ventyx's experience, the complexity and time to generate an end-use forecast would not significantly improve the demand forecast in the mid-term. The Power Advisory review concluded that end-use models are likely not justified for the NL system, given the incremental cost.[103]

We understand that the commitment to adopt end-use modelling requires additional resources, time, data, and the cooperation of Newfoundland Power. Econometric modelling techniques Nalcor uses is an accepted load forecasting methodology however, best practices suggest end-use modelling techniques.

1.3.2 General Service Customer

The general service customer includes rural customers served by NLH and customers served by Newfoundland Power, similar to the domestic sector. MHI noted that Nalcor's general service methodology is a combination of regression modelling and linear extrapolation techniques and that they have performed extremely well in the past.[104]

No issues have come to our attention regarding the general service customers forecast used.

1.3.3 Industrial Customers

In 2012, industrial customers included three large customers: CBPP, Come-by-Chance oil refinery ("North Atlantic Refining") and a cooper mine at Duck Pond ("Teck Resources Limited").

Duck Pond operations were forecast to shut down in 2014, with Praxair and Vale operations forecast to begin during 2013 to 2015 operations respectively.

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[98] NAL0019060 – Reference to the Board – Review of Two Generation Expansion Options For The Least-Cost Supply of Power To Island Interconnected Customers For The Period 2011 – 2067 - March 30, 2012
[99] NAL0019060 – Reference to the Board – Review of Two Generation Expansion Options For The Least-Cost Supply of Power To Island Interconnected Customers For The Period 2011 – 2067 - March 30, 2012
[100] Newfoundland and Labrador Hydro - 2014 Investigation and Hearing into Supply Issues and Power Outages on the Island Interconnected System, PUB-NLH-058 - 2014
[101] Nalcor Energy – Response to Grant Thornton Question 5.2 – Nalcor Response - GT RFI Q5.2_2014 Newfoundland and Labrador Hydro Planning Process Review – VENTYX FINAL March 21.docx – March 21, 2014
[102] Nalcor Energy - Grant Thornton RFI 5.2 – Power Advisory – Review of NL Electricity System – 2015 – October 26, 2015
[103] Nalcor Energy – Response to Grant Thornton Question 5.2 – Nalcor Response – June 8, 2018
[104] NAL0018917 - Manitoba Hydro International: Report on Two Generation Expansion Alternatives for the Island Interconnected Electrical System, Volume 2: Studies - January 2012

MHI concluded that Nalcor's case-by-case methodology is reasonable considering the small industrial customer base on the island, but noted that the amount of variability due to load variations is high and could materially impact CPW results.[105]

The following observations were noted from other provinces for industrial customers:

- Utilities in Alberta rely on industrial load input similar to NLH approach. This means that the utilities projection for industrial load would be based on input from its customers;
- Utilities in British Columbia as per Site C report from Deloitte[106] stated that forecasting is based on projection of current and potential customers, including assumptions made on major capital projects; and
- In its preferred development plan, MHI discussed a two "pronged" approach – short term 3 to 5 year forecast for each industrial customers and a "Potential Large Industrial Loads" which encompasses sector growth, additional and loss of customers.[107]

The industrial customer has high risk of forecast error and prone to volatility due to potential load change in customers and sensitivity to economic conditions, especially given only four customers represent approximately 20% of the total energy requirements of the island.

For example if CBPP closes, load forecast would likely be overstated as it is the largest customer on island with approximately 50% of all industrial energy use during the forecast period to 2067. Additionally during sanctioning proceedings, the P.U.B. noted that without CBPP there would be no energy deficit during 20 year planning period.

1.3.4 Other Observations

- The load forecast projected in 2001 for 2010 resulted in a 124% overstatement due to the closure of two pulp and paper mills[108].
- Price elasticity was not included in Planning Load Forecast for NLH industrial customers.[109] Price elasticity means that as the price increases the demand will decrease which may have reduced the forecasted need;[110]
- Conservation and demand management ("CDM") program adjustments over the long term were not factored into the load forecast. Marbek Resource Consultants Ltd. issued a report in 2008.[111] The objective of this report was to identify potential contribution of CDM technologies to the residential, commercial and industrial sectors. This report notes that industrial customers have the potential to achieve substantial savings in CDM;
- The 2011 Annual Report for Vale S.A.[112] includes a projected exhaustion date for Voisey's Bay open pit of 2023. Nalcor's load forecast did not incorporate the impact of this information, which may have decreased the industrial load forecast. We note that in 2018, Voisey's Bay extension from an open pit to underground mining project was announced, however this life extension related to a key industrial customer was not confirmed at the time of sanctioning.

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[105] NAL0018917 - Manitoba Hydro International: Report on Two Generation Expansion Alternatives for the Island Interconnected Electrical System, Volume 2: Studies - January 2012
[106] Deloitte LLP - British Columbia Hydro and Power Authority – British Columbia Utilities Commission Inquiry respecting Site C – Project No. 1598922 – September 8, 2017
[107] The Public Utilities Board – Report on the Needs For an Alternative To (NFAT), Review of Manitoba Hydro's Preferred Development Plan - June 2014
[108] NAL0018916 - Manitoba Hydro International: Report on Two Generation Expansion Alternatives for the Island Interconnected Electrical System, Volume 1: Summary of Reviews - January 2012
[109] Nalcor Energy - Grant Thornton Question 2.6 – Nalcor Response – May 29, 2018
[110] Ausgrid – Appendix 5 Price Elasticity of Demand, November 2015 and RAND Corporation -Bernstein and Griffin, "Regional Differences in the Price-Elasticity of Demand for Energy (2005)
[111] Marbek Resource Consultants Ltd. – Conservation and Demand Management (CDM) Potential Newfoundland and Labrador, Residential, Commercial and Industrial Sectors - January 31, 2008
[112] Vale S.A. 2011 Annual Report - 2011

Price elasticity and CDM were excluded from the forecast which may have resulted in an overstatement of the industrial forecast during the projected period.

1.3.5 Review of macro-economic inputs and other sources

Nalcor applied numerous macro-economic variables within their econometric model, such as gross domestic product ("GDP"), personal disposable income ("PDI"), population and average housing starts.[113]

We compared forecasts prepared by the CBOC, an independent and evidence-based group of experts in forecasting and economic analysis[114] with Nalcor's forecasts prepared during the same time.

1.3.6 Findings and Observations

We note the following:

- CBOC projected housing starts during 2027 to 2031 from 826 to 530 units[115] (36% decrease) respectively, while Nalcor has projected 1,505 to 1,230 units[116] (18% decrease) respectively.
- Population projected from CBOC for the period 2027 to 2031 decreased (approximately) 498,000 to 486,000 (2% decrease) respectively,[117] while Nalcor maintained consistent projections (approximately) 513,000 population per year since 2018. [118]

1.3.7 Statistics Canada

We compared the 2012 Statistics Canada[119] (four medium population projection scenarios prepared for 2009 to 2036 for all Canadian provinces) with Nalcor's projections. Newfoundland and Labrador's average population projections per Statistics Canada's forecast is approximately 1% lower per year for the period 2027 to 2031 than applied by Nalcor in their load forecasting.

1.3.8 The National Energy Board

The National Energy Board ("NEB") is an independent federal regulator. According to NEB, its purpose is to promote safety and security, environmental protection and efficient infrastructure and markets in the Canadian public interest within the mandate set by Parliament for the regulation of pipelines, energy development, and trade. In November 2011 the NEB released a report entitled *Canada's Energy Futures: Energy Supply and Demand Projections to 2035* ("NEB report").[120] The NEB report provided a national and provincial energy market assessment including an outlook for supply and demand to 2035. Because of differences in methodology and reporting of electricity projections between the NEB report and Nalcor's Interconnected Island PLF, a detailed comparison is not possible.

It appears that Nalcor has followed good utility practice regarding the use of macro-economic data sources; however, we note that there were alternatives sources of information at that time (i.e. CBOC and Statistics Canada). We understand that the macro-economic data was provided to Nalcor by the GNL - Department of Finance. Additional sources of information (i.e. CBOC and Statistics Canada) does not appear to have been utilized.

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[113] NAL0019056 - Nalcor's Submission to the Board of Commissioners of Public Utilities with respect to the Reference from the Lieutenant-Governor in Council on the Muskrat Falls Project - November 10, 2011
[114] The Conference Board of Canada - https://www.conferenceboard.ca/about-cboc/default.aspx?AspxAutoDetectCookieSupport=1
[115] The Conference Board of Canada – Provincial Outlook 2012 - Long-term Economic Forecast - 2012
[116] NAL0107072 – Department of Finance Economic Forecast for NL – April 2012
[117] The Conference Board of Canada - Provincial Outlook 2012 – Long-Term Economic Forecast - 2012
[118] NAL0107072 – Department of Finance Economic Forecast for NL – April 2012
[119] Statistics Canada – Population Projections for Canada, Provinces and Territories, 2009 to 2036 – June 2010
[120] NAL0107315 - National Energy Board - Canada's Energy Futures: Energy Supply and Demand Projections to 2035, - November 2011

1.4 Historical Accuracy

Determining load projections is a difficult task as variations between actuals and forecasted results must be expected. During DG2 phase, MHI examined the accuracy of the planning load forecasts prepared by NLH for the 10 year period 2001 to 2010[121] to assess if Nalcor's load forecasts were *"conducted with due diligence, skill, and care consistent with acceptable utility practices."*[122]

1.4.1 Findings and Observations

- Ten year history average variance of 8.9% overstated load forecast (including all customers); and
- Ten year history average variance by customer (i.e. domestic, general service, industrial) had a range between -5% (domestic was more than forecast) to 61.1% (industrial was less than forecast)

1.4.2 Peak Demand

"The system peak is the maximum hourly demand placed on the Interconnected system".[123] The system peak is made up of four sub-groups, which are Newfoundland Power peak demand, NLH rural peak demand, industrial demand and NLH transmission peak demand. Historically, the system peak demand forecasts have been projected higher than actuals, which is tied to the decrease in industrial customer loads during this time.[124] The 2001 PLF to 2010 PLF resulted in a low, high, and average of approximately 0, 15, and 6 percent respectively from forecasted and actual loads.

The 2012 PLF for the Interconnected Island Option on average compared to actuals is approximately 1% lower per year than forecasted. This variance falls in line with MHI's recommended 1% variance per year from forecast.[125]

1.5 Oversight and Quality Control

The load forecast was prepared by Nalcor's Senior Market Analyst.[126] According to the Senior Market Analyst "*there is no official QC process, except that it's (I guess) the process is you are forecasting performance….There is no formal process of saying yes that forecast is a good forecast or that forecast is approved."*[127]

Nalcor's Manager of System Planning indicated the following regarding his review of the load forecast:

"I would review it but I mean I'm not a load forecaster. There would have to be something grossly wrong with it for me to you know. We put faith in people that we have there. The methodologies that we use have been reviewed by people that know – and accept it as being reasonable. If I had to sit down and do a load forecast – no, I wouldn't know where to start."[128]

During our audit, we asked Nalcor to describe the internal review process of the load forecast conducted. The following response was provided by Nalcor:

"The development and completion of long term planning load forecasts resided within the System Planning Department's Market Analysis Section at the time of completion of the 2010 Planning Load Forecast (PLF)

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[121] NAL0018802 - Exhibit 103: Island Interconnected Requirements - Actual and Forecasts – Muskrat Falls Review
[122] NAL0018916 - Manitoba Hydro International: Report on Two Generation Expansion Alternatives for the Island Interconnected Electrical System, Volume 1: Summary of Reviews - January 2012
[123] NAL0018917 - Manitoba Hydro International: Report on Two Generation Expansion Alternatives for the Island Interconnected Electrical System, Volume 2: Studies - January 2012
[124] NAL0018917 - Manitoba Hydro International: Report on Two Generation Expansion Alternatives for the Island Interconnected Electrical System, Volume 2: Studies - January 2012
[125] NAL0018916 - Manitoba Hydro International: Report on Two Generation Expansion Alternatives for the Island Interconnected Electrical System, Volume 1: Summary of Reviews - January 2012
[126] Nalcor's Senior Market Analyst - Interview – April 11, 2018
[127] Nalcor's Senior Market Analyst – Interview - April 11, 2018
[128] Nalcor's Manager of System Planning – Interview – April 12, 2018

and the 2012 PLF... As such, there was no formal review and acceptance of the load forecast but instead, an open communication and discussion of load forecast results between the analysts involved."[129]

There is a lack of quality control review surrounding the load forecasting process. The lack of such review creates a risk that an error in the load forecasting process would go undetected.

1.6 Price Elasticity of Demand

Good utility practice for determining load forecast would include consideration regarding price elasticity factors to adjust for the effects of increasing electricity prices on electricity demand. NLH has included price elasticity factors in its forecast but not for all customers.

We asked Nalcor to confirm if price elasticity was included in the 2010 and 2012 PLFs and if not included to explain the rationale for not including. Nalcor's response is as followings:

"It is confirmed that both 2010 Planning Load Forecast model and the 2012 Planning Load Forecast model for the Island system included price elasticity factors. Within both 2010 PLF and 2012 PLF models, price elasticity factors were included for the following load sectors:

- *Residential electricity consumption sector of Newfoundland Power's service territory;*
- *Residential electricity consumption sector of Hydro's Island Rural service territory;*
- *General service/commercial electricity consumption sector of Hydro's Island Rural service territory.*

Neither the 2010 PLF nor 2012 PLF models included electricity price elasticity factors for:

- *General service/commercial electricity consumption sector of Newfoundland Power; or*
- *Hydro's Island industrial customers.*

A price elasticity factor for the general service\commercial electricity consumption sector of Newfoundland Power was not included because a statistically significant relationship between electricity price and electricity consumption levels for this customer group was not able to be analytically established. The lack of statistical significance for this customer group has always been interpreted to be indicative of an inelastic or low price elasticity that was not measureable.

A price elasticity factor for Hydro's Island industrial customers was not included because the limited number of customers and diverse nature of the industrial customer's business precluded the ability to statistically measure a single electricity price elasticity factor for this customer group. According to Nalcor, this limitation was compensated for by doing a sensitivity analysis case based on the loss of an industrial customer."[130]

Grant Thronton would expect the Newfoundland Power General Service/Commercial customer and Industrial Customers to respond to price increases similar to other customer sectors and the load forecast should include price elasticity effects.[131]

At DG2, the load forecast was used for both the Isolated Island Options and the Interconnected Island Option. Each alternative was based on the same customer electricity rate projections.

At DG3 different customer rate projections were used. As customer rates were forecast higher for the Isolated Island option, the effect would be a greater load reduction due to demand elasticity.

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[129] Nalcor Energy - Response to Grant Thornton Question 3.2 – May 29, 2018
[130] Nalcor Energy Response to Grant Thornton Question 2.6
[131] Energy Information Administration, Steven Wade, "Price Responsiveness in the AEO2003 NEMS Residential and Commercial Building Sector Models" and RAND Corporation, Bernstein and Griffin, "Regional Differences in the Price-Elasticity of Demand for Energy (2005)

Based on our review we noted that Nalcor does not include price elasticity factors in its NP General Service customers or Industrial customers. We would expect these customers to respond to price increases similar to other customer sectors.

1.7 Conservation and Demand Management

Nalcor included Conservation and Demand Management ("CDM") as an alternative option but it was dismissed early as not viable to meet the growing demand stating it did not have much history with CDM and participant rates are low.[132]

In Nalcor's report filed in November 2011 to the P.U.B., Nalcor states that it has not explicitly incorporated utility sponsored CDM programs savings targets into its planning load forecast due to the uncertainty of achieving dependable firm outcomes. According to Nalcor in this report the response to CDM programs and initiatives has been modest and lagging targets.

Navigant,[133] and Marabek Resource Consultants Ltd.[134] promote the consideration of CDM.

Findings and Observations

- Nalcor took into account technological improvements that reduce energy demands in their econometric modelling technique. CDM incentive based programs were not factored into the load forecast at DG2. To date we have not been provided with any support which demonstrates CDM incentive programs were incorporated into the load forecast used in DG3;
- Navigant concluded that Nalcor could consider the impact of a longer term CDM initiative;
- MHI stated that CDM should be included as a supply side option;[135]
- The Marbek Resource Consultants Ltd in 2008 (pre-sanctioning) and ICF International in 2015 (post-sanctioning) reports that there is a potential for CDM incentive programs;[136]
- Other jurisdictions of utility mega-capital projects consider CDM programs in load forecast or as a resource option; and,
- Newfoundland Power includes the impact of CDM programs in its energy sales forecast.

CDM incentive based programs appears not to have been included as a factor in load forecasting, either as a load reduction or as a resource option. As a result, load forecast may have been overstated.

1.8 System Planning

1.8.1 Background – System Planning Generation and Transmission

Identifying the need and timing for new sources of reliable generation is essential for utility systems to meet the energy requirements and energy demands identified through load forecasting. NLH's System Planning department is responsible for ensuring the island's generation capability will meet the projected load forecast.

During DG3, NLH had established criteria related to the appropriate reliability at the generation level for the island's electricity system which sets the timing of generation course additions. These criteria established

[132] NAL0018957 - Nalcor's Final Submission to the Board of Commissioners of Public utilities with respect to the reference from the Lieutenant-Governor In Council on the Muskrat Falls Project - March 2, 2012
[133] NAL0018800 – Navigant consulting Ltd. Independent Supply Decision Review - September 14, 2011.
[134] Marabek Resource Consultants Ltd. – Conservation and Demand Management ("CDM") Potential Newfoundland and Labrador Residential, Commercial and Industrial Sectors Summary Report - January 31, 2008.
[135] ICF International – Newfoundland and Labrador Conservation and Demand Management potential Study - 2015, June 2015.
[136] ICF International –Residential Sector Final Report (June 2015), Industrial Sector Final Report (June 2015), Commercial Sector Final Report (August 2015)

the minimum level of capacity and energy installed in the system, to ensure an adequate supply to meet consumer firm requirements at the designated level of reliability.[137]

1.8.2 System Reliability

NLH's plan was to have sufficient generating capacity for a targeted Loss of Load Hours ("LOLH") of no more than 2.8 hours per year and sufficient generating capability to supply all of its firm energy requirements with firm system capability.[138] The capacity criterion of LOLH is a "*probabilistic assessment of the risk that the electricity system will not be capable of serving the system's firm load for all hours of the year."*[139] NLH used Strategist to calculate the LOLH.

NLH reviewed the need for additional capacity within the island's system to ensure reliable supply for their customers in the situation of an unplanned failure that may require reserves for power generation assets. The process of determining the appropriate reserve capacity for the island's system is a common approach used in the utility industry, and the P.U.B. has reviewed and accepted this practice[140].

Subsequent to the sanctioning phase for the Muskrat Falls project, The Liberty Consulting Group ("Liberty") filed a July 6, 2015 report regarding to Review of Prudence Issues, which discussed supply planning process and several issues within NLH. The following was noted by Liberty:

"Using an LOLH calculation certainly reflects good practice. Good planning, however, also requires examination of the reserve levels that result, in relation to the kinds of supply contingencies that merit consideration[141]."

Therefore, consideration of maintaining the LOLH criterion, in addition to planning for reserve levels is consistent with good practice.

Based on our review Hydro's generation planning criteria of LOLH of 2.8 hours per year appears consistent with good utility practice. However we noted that subsequent to sanctioning, P.U.B.'s expert (Liberty) in the Outage Inquiry found there was a lack of focus on reserve levels regarding its system planning processes. This may result in employing generation resources sooner to meet demand.

1.8.3 System Needs Identification

We reviewed Nalcor's analysis of system need identification. Our procedures focused on reviewing the existing island grid capacity and firm energy and comparing to Decision Gate 3 load forecasts.

We reviewed the energy balance deficits calculated by Nalcor in Decision Gate 3, based on a LOLH of 2.8 hours per year, and found no discrepancies.

We reviewed the system capability filed by NLH in their 2013 General Rate Application[142] and compared it to the evidence in Decision Gate 3 for consistency. Based on our review, there were no discrepancies between the system capabilities presented in each document.

1.8.4 Additional Issues Identified

We reviewed system planning matters that were raised in the MHI January 2012 Report , related to North American Electric Reliability Corporation ("NERC") compliance; transmission reliability – return period; and reliability assessment – use of probabilistic model. [143]

Based on our review, the issues identified during Decision Gate 2 appear to have been addressed by Nalcor.

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[137] NAL0000197 – Lower Churchill Project Phase 1- Decision Gate 3 Support Package
[138] NAL0000197 – Lower Churchill Project Phase 1- Decision Gate 3 Support Package
[139] NAL0000197 – Lower Churchill Project Phase 1- Decision Gate 3 Support Package
[140] NAL0000197 – Lower Churchill Project Phase 1- Decision Gate 3 Support Package
[141] The Liberty Consulting Group - Prudence Review of Newfoundland and Labrador Hydro Decisions and Actions Final Report – July 6, 2015
[142] Newfoundland and Labrador Hydro - 2013 General Rate Application - 2013
[143] NAL0018916/NAL0018917 - - Manitoba Hydro International: Report on Two Generation Expansion Alternatives for the Island Interconnected Electrical System - January 2012

2.1 Financial Analysis of Two Options

2.1.1 Cumulative Present Worth ("CPW") Analysis

Background and methodology

Nalcor completed a CPW analysis for both the Interconnected Island Option and the Isolated Island Option.

As defined in Nalcor's Submission to the P.U.B. in March 2012, *"Cumulative present worth refers to the present value of all incremental utility capital and operating costs incurred to meet a specified load forecast in a manner that complies with a prescribed set of reliability criteria."*[144] The calculation of CPW considers only incremental capital expenditures, fuel costs, power purchase costs and other operating costs and does not consider the future cash in-flows related to revenues.[145]

CPW was calculated based on the service life of the Labrador-Island Transmission Link.[146]

Nalcor used a computer modelling software, Ventyx Strategist ("Strategist"), to prepare the CPW, in order to identify the least-cost option.

Strategist evaluates all of the various combinations of resources and produces a number of generation expansion plans, including the least cost plan which supplies the load forecast within the context of the power system reliability criteria.[147] The generation expansion plan from Strategist determines the generating assets, such as combustion turbines, wind, hydro and refurbishments to the Holyrood generation station that was required under both options to meet demand.

Key inputs incorporated into Strategist for the CPW analysis included:

- Existing generation capacity and energy capability;
- Load forecast;
- Capital cost estimates;
- Fuel cost;
- Operating and maintenance expenses; and
- Discount rate.

2.1.2 Benchmarking

As noted in the introduction to this report, the complete Muskrat Falls Project included a 500MW HVdc transmission link between Newfoundland and Nova Scotia – referred to as the ML. The ML portion of this project was beyond the scope of our engagement. However, in reviewing the methodology and assumptions used by Nalcor in its CPW analysis it was determined that a comparison of key assumptions used by Emera's subsidiary, NSP Maritime Link Incorporated ("NSPML"), in its filing on January 28, 2013 to the NSUARB for approval of the Maritime Link Project, would provide useful information. Below are comparisons of several inputs into both projects:

- Methodology – NSPML used a net present value analysis, which considers cash outflows over the duration of the analysis. Nalcor used a cumulative present worth analysis, which considers incremental cash outflows only. As such, both analysis were completed based on cash outflows only;
- Period of study – The NSPML analysis used a time period of 35 years which matched the period in which NSPML would own the Maritime Link transmission asset. The total useful life of the asset was estimated to be 50 years, with ownership transferring to Nalcor for the final 15 years;

[144] NAL0019055 - Nalcor's Final Submission to the Board of Commissioners of Public Utilities with respect to the Reference from the Lieutenant-Governor in Council on the Muskrat Falls Project - March 2, 2012
[145] NAL0019060 - Review of Two Generation Expansion Options for the Least-Cost Supply of Power to Island Interconnected Customers for the period 2011-2067 - March 30, 2012
[146] NAL0000197 - Lower Churchill Project Phase 1- Decision Gate 3 Support Package
[147] NAL0106812 – System Planning outline material PUB Review v3.docx

- Capital Structure – NSPML utilized a capital structure of 70/30 to 65/35, compared to 75/25 capital structure utilized in Nalcor's CPW analysis;
- Strategist – NSUARB incorporated the long-term generation planning tool Strategist developed by Ventyx and retained Ventyx to conduct their analysis. Nalcor applied Strategist as well, but performed the analysis themselves;
- Discount Rate – NSPML utilized a discount rate of 5.95% in their study, based on a cost of equity of 9.0% and a cost of debt of 4.0%. In Nalcor's CPW analysis, it used a discount rate of 7%, which was based on its WACC, utilizing a cost of equity of 9.25% and a cost of debt of 6.25%;
- Transmission losses – NSUARB utilized transmission losses of 9.2%. This was higher than the transmission losses of 5.15% used in Nalcor's CPW analysis. Based on our analysis, 5.15% was considered acceptable; however, the impact of using higher transmission losses up to 10% would have resulted in a possible increase to the CPW of the Interconnected Island Option;
- Capital cost estimates – NSUARB provided capital cost estimates using P50, P90 and P97 factors in their contingency for inclusion of capital cost estimates, but based the capital cost for the Maritime Link facilities under a P50 estimate. The P-factor used is consistent with Nalcor's determination of contingency in the capital cost section, however, Nalcor never presented capital cost estimates using various P-factors for information purposes; and
- Fuel – NSPML forecast natural gas and oil prices to increase an average of 2% to 4% per year from 2015 to 2040. This is consistent with Nalcor's approximate average increase of 2% yearly from 2012 to 2067 for fuel.

2.1.3 Least-Cost Option

CPW was calculated for both options for identifying the least-cost option. In the DG3 Support Package, the Interconnected Island option had the lowest CPW and was considered the least-cost option. The schedule below summarizes the CPW for both options[148]:

Comparison of CPW Estimates for the Two Supply Options					
	Interconnected Island Option		Isolated Island Option		Differences
	CPW ($ 000s)	%	CPW ($ 000s)	%	CPW ($ 000s)
Fixed Charges	319,400	3.8	2,555,943	23.7	(2,236,543)
Operating Costs	258,939	3.1	752,448	7.0	(493,509)
Fuel	1,320,530	15.8	6,706,178	62.2	(5,385,648)
Power Purchases	6,467,127	77.3	763,770	7.1	5,703,357
Totals	**8,365,997**		**10,778,339**		**(2,412,342)**

As per the schedule above, the major input categories of the CPW calculation for each option included[149]:

- Fixed charges – included depreciation expense on capital expenditures (excluding the capital cost estimate of the Muskrat Falls generating asset, Labrador transmission assets, and Labrador Island transmission link);
- Operating costs – included fixed and variable operating and maintenance costs for each asset that is included in fixed charges;
- Fuel costs – included two types of fuel; Number 2 fuel used in CT and CCCT generating units and Number 6 fuel (which can include 0.7% sulphur or 2.2% sulphur) used only at the Holyrood Thermal Generating Station; and
- Power Purchase Costs – for the Isolated Island option, power purchase costs represented the power purchased from non-utility generators. For the Interconnected Island Option, power purchase costs included recovery of costs related to Muskrat Falls generating facility, Labrador transmission assets and the Labrador-Island HVdc transmission link.

2.1.4 CPW and Strategist Procedures

Prior to reviewing the inputs incorporated into the CPW, we completed the following procedures to gain an understanding of the CPW methodology and process to identify best practice:

- Reviewed the CPW methodology used to determine the least cost option;
- Benchmark the time period of study against other projects in the utilities industry; and
- Gained an understanding of Strategist, the inputs and assumptions used in the CPW analysis.

[148] NAL0018691 - Manitoba Hydro International Review of the Muskrat Falls and Labrador Island HVdc Link and the Isolated Island Options - October 2012

[149] NAL0018691 - Manitoba Hydro International Review of the Muskrat Falls and Labrador Island HVdc Link and the Isolated Island Options - October 2012

2.1.5 Findings/Observations – CPW and Strategist

During the P.U.B. Review, MHI agreed that Nalcor's use of Strategist and CPW was reasonable in identifying the least-cost option. The Consumer Advocate accepted MHI's finding that the CPW analysis was completed using best practice[150].

Prior to DG3, MHI was engaged by the Government to review the analysis of the Isolated Island and Interconnection options and to determine the least cost. MHI noted, *"the CPW approach is an acceptable method by which to measure the present worth of alternative options. It focuses only on costs, including capital expenditures for the construction of new facilities, operating costs, fuel costs, financing costs and the cost of purchased power."*[151]

CPW methodology in assessing the lowest cost option is both used and considered acceptable practice in the utilities industry.

2.1.6 Time Period of Study

Per Nalcor, CPW was calculated using a 50 year term (from 2012 to 2067) which matched the Labrador Island Link service life.

We have noted that:

- Matching the number of years in the analysis to the service life of a significant asset in the analysis is common in the utilities industry; and
- Balance is required as there is inherent risk in long term forecasts. In particular, the load forecast and fuel forecast are more difficult to predict the longer the forecasted period. Risk mitigation can be performed using sensitivity analysis and understanding the impact of key inputs into the analysis and decision.

The time Period of Study used by Nalcor in assessing the least-cost option is within acceptable utilities industry practice.

2.1.7 Strategist & CPW Process

To gain an understanding of Strategist and the CPW analysis performed by Nalcor Grant Thornton attended a presentation that walked through the process performed at Nalcor (presented on April 20, 2018). The presentation included:

- An explanation of the software and process in capturing data; and
- Financial models identified that re-calculated the CPW for both options at DG3. The financial models were used for sensitivity analysis of both options.

We reviewed the CPW models to identify key inputs (and possible exclusions) into the CPW analysis completed by Nalcor at DG3.

The DG3 support package refers to assumptions and costs that have not been included in the CPW analysis.[152] Nalcor excluded inputs that they considered the same under both options and would have the same impact on the CPW for both options. For example, annual operating and maintenance costs for the existing hydroelectric plants on the island, including those owned by Hydro, Newfoundland Power, and Deer Lake Power.

[150] NAL0019060 - Review of Two Generation Expansion Options for the Least-Cost Supply of Power to Island Interconnected Customers for the period 2011-2067 - March 30, 2012
[151] NAL0018691 - Manitoba Hydro International Review of the Muskrat Falls and Labrador Island HVdc Link and the Isolated Island Options - October 2012
[152] NAL0000197 - Lower Churchill Project Phase 1- Decision Gate 3 Support Package

2.1.8 CPW Inputs

As noted above, CPW inputs included:

- Existing generation capacity and energy capability;
- Load forecast;
- Capital cost estimates ("CCE");
- Fuel cost;
- Operating and maintenance expenses; and
- Discount rate

2.1.9 Existing Generation Capacity and Energy Capability

The island's existing system energy capability and future deficits were discussed previously in this report. Refer to this noted section for additional procedures completed.

2.1.10 Procedures-Existing Generation Capacity and Energy Capability

To gain comfort of the appropriate incorporation of the existing system's capacity and capability we performed the following procedure:

- Determined the island's existing generation capacity and energy capability system was properly incorporated for both options during DG3 CPW scenarios.

2.1.11 Findings/Observations – Existing Generation Capacity and Energy Capability

In addition to the work performed as described in the system planning section of our report we performed additional procedures specifically related to the CPW analysis at DG3. Our procedures included confirming if the existing capacity and capability in the DG3 support package was included for both options in Strategist.

2.1.12 Load Forecast

The load forecasts developed between 2012 and 2067 for both alternatives is used to determine the total island's energy requirements and electricity demands for the period. The projections inputted into Strategist develop generation expansion plan scenarios to optimize the least cost option to satisfy the total island's energy requirements and electricity demands.

2.1.13 Procedures – Load Forecast

In addition to the procedures noted in the Load Forecast section of the report, the following procedures were also completed with respect to the CPW:

- Confirmed existing generation system was incorporated into Strategist.
- Confirmed the planning load forecasts at Decision Gate 3 were incorporated into Strategist.
- Compared the Strategist output report showing the generation expansion plans (assets and years placed into and out of service) to the CPW calculation.

2.1.14 Findings/Observations – Load Forecast

Load forecasting methodology and process for both the Interconnected Island Option and Isolated Island Option was discussed in the above Load Forecasting section of this report.

As part of the CPW analysis at DG3, load forecasts developed for each alternative were applied in Strategist separately to develop generation expansion plan scenarios to meet the energy requirements and electricity demands from the load forecasts.

Grant Thornton compared the 2012 PLF total island energy requirements to the Strategist output report and confirmed the generation expansion plans under both alternatives met the 2012 PLF requirements.

During the DG2 process, MHI reviewed the CPW and noted the following:

"A major input to the cumulative present worth analysis is the load forecast, and as a result any large changes in the load would have a significant impact. For example, should the existing pulp and paper mill

cease operations, and its generation capacity be available for use on the system, and should the capital costs of both the Muskrat Falls Generating Station and Labrador-Island Link HVdc project increase by 10%, the cumulative present worth for the two Options would be approximately equal."[153]

Based on MHI's analysis of the inputs within the CPW, the risks with regards to the load forecast are further magnified considering the 50 plus year period.[154]

2.1.15 Capital cost estimate and fixed charges

Fixed charges are based on investments in additional generating assets required between 2012 and 2067 in order to meet demand. The fixed charges included in the CPW model consist of the following:

- Depreciation expense of capital expenditures based on the in-service cost of the assets spread over their useful lives;
- Return on Rate Base assuming a return of 7% on the undepreciated portion of the assets;
- Insurance which had been calculated assuming a rate of 0.03% on the in-service capital costs of the assets over their useful lives;

The fixed charges total in the CPW is significantly higher under the Isolated Island option due to the fact the capital cost of the Muskrat Falls Generation, Labrador Transmission Assets and the Labrador-Island Transmission Link have been included in the Power Purchases total in the CPW. Since the majority of power generation will come from Muskrat Falls, less additional generating assets are required under the Interconnected Island option.

See the section in the report titled "Capital Cost Estimate" for a detailed discussion.

2.1.16 Background – Interconnected Island Option

For the Interconnected Island option power generation comes from the following assets over the 50 year period:

- Muskrat Falls Generating facility and LTA through a Power Purchase Agreement ("PPA"), which is included in the Power Purchases total of the CPW;
- The LIL through a Cost of Service model, which is also included in the Power Purchases total of the CPW; and
- Additional generating assets required to meet demand. The additional generating assets required consists of ten 50MW CTs, one CCCT, and ten Holyrood CPs. These assets are included in the fixed charges total of the CPW.

2.1.17 Background – Isolated Island Option

For the Isolated Island option the following generating assets were required over the 50 year period:[155]

- Fifteen – 50MW Combustion Turbines ("CTs") at $72.1 million each;
- Seven - Combined Cycle Combustion Turbines ("CCCTs") ranging from $261.9 million to $292.5 million each;
- There are three Holyrood electrostatic precipitators ("ESPs") and flue gas desulphurization systems, also known as "scrubbers," and low NOx burners to be installed at the Holyrood generating station. The total capital costs for these units included in the CPW is $569.9 million. In 2008, Stantec issued a report on the estimated cost of these assets and noted NLH "*are currently exploring the options to reduce the particulate and sulphur dioxide emissions at the station. To meet this objective,*

[153] NAL0018916 - Manitoba Hydro International: Report on Two Generation Expansion Alternatives for the Island Interconnected Electrical System, Volume 1: Summary of Reviews - January 2012
[154] NAL0018916 - Manitoba Hydro International: Report on Two Generation Expansion Alternatives for the Island Interconnected Electrical System, Volume 1: Summary of Reviews - January 2012
[155] NAL0000197 - Lower Churchill Project Phase 1- Decision Gate 3 Support Package
NLH – Cumulative Present Worth Analysis – PLF 2012 Iteration #1 August – Isolated Island Alternative

electrostatic precipitators ("ESP") and a common flue gas desulphurization ("FGD") system would need to be installed at the station"[156] *Stantec also highlighted "the environmental equipment was selected based on this design fuel case and on the basis of meeting the requirements of Newfoundland and Labrador Regulation 39/04 – Air Pollution Control Regulations, 2004 under the Environmental Protection Act (O.C. 2004 – 232)".;*

- Refurbishments to extend the life of the Holyrood generating station are required between 2013 and 2032. There are four refurbishments each spanning a five year period, for a total of $417.5 million;
- Hydro facilities including Island Pond, Portland Creek and Round Pond; and
- Twenty seven wind farms ranging from $61.3 million for a 25MW wind farm to $66.2 million for the 27MW wind farms.

2.1.18 Procedures - Fixed Charges

To gain an understanding of fixed charges we performed the following procedures:

- Identified and reviewed asset additions for the Interconnected Island option and the Isolated Island option;
- Reviewed the reasonability of cost determination; and
- Where possible, compared the total capital cost included in the CPW to supporting studies.

2.1.19 Findings/Observations - Fixed Charges

2.1.20 Interconnected Island Option

We reviewed the addition of assets under the Interconnected Island Option and agreed to support, where applicable. Additionally, see the section titled "Capital Cost Estimate" for a detailed discussion.

[156] NAL0018877 – Precipitator and Scrubber Installation Study Holyrood Thermal Generating Station – November 20, 2008

2.1.21 Isolated Island

We reviewed the addition of assets under the Isolated Island option and agreed to support, where applicable. There were no exceptions noted except with regards to the refurbishments required to the existing Holyrood generation station. In 2012, AMEC completed a study indicating a total cost of $353 million for the refurbishments.[157] Nalcor included $418 million in the CPW calculation and informed us the difference was due to Nalcor including an 18% contingency.[158]

2.1.22 Operating and maintenance costs

Background

Operating and maintenance costs were included in the CPW calculation for both options summarized as follows:[159]

Interconnected Island – Operating costs	Isolated Island – Operating costs
$258.9 million	$752.4 million

The operating cost is higher under the Isolated Island option due to more generating assets required under this option.

For the Interconnected Island Option, there are also additional operating costs on the Muskrat Falls Generation and the LIL assets. While these operating costs have been discussed in this section, they are not included in the $258.9 million of operating costs. Instead, they are included in the CPW in the Power Purchases total, as they are incorporated through a Power Purchase Agreement.

Fixed and/or variable operating costs on all generating assets and the LIL were calculated based on the inputs determined by Nalcor as follows[160].

Facility	Fixed Annual O&M Cost $/kW (2012$)	Variable O&M Cost $/kW (2012$)
Island Pond	$16.92	N/A
Portland Creek	$19.46	N/A
Round Pond	$21.15	N/A
Wind (new)	$32.78	$6.20
Holyrood CCCT	$15.00	$5.80
Greenfield CCCT #1	$15.00	$5.80
Greenfield CCCT #2	$15.00	$5.80
Holyrood Existing 3 Units	$43.49	$1.40
CTs Existing	$11.01	N/A
CTs New	$11.01	$5.62
Holyrood FGD and ESP	$12 – 16 million per year	
Muskrat Falls	$10 million (2018) to $33 million (2067) nominal	
Labrador Island Transmission	$18 million (2017) to $57 million (2067) nominal	

[157] NAL1013367 – AMEC – Nalcor Holyrood Generating Station Life Extension Review – April 25, 2012
[158] Nalcor Energy – Response to Grant Thornton Request S.56
[159] NAL0018691 – MHI Review of Muskrat Falls and Labrador Island HVdc Link and the Isolated Island Options – October 2012
[160] NAL0000197 - Lower Churchill Project Phase 1- Decision Gate 3 Support Package

In June 2017, Stan Marshall (Nalcor's current CEO) noted that the operating and maintenance costs for Muskrat Falls were updated from $34 million annually to $109 million annually, starting in 2020 when the project is completed. This update included $9 million related to environmental monitoring[161].

2.1.21 Procedures - Operating and Maintenance Cost

- Considered whether in the operating and maintenance costs included in the CPW were reasonably determined and whether they would have an impact on the overall decision.
- Inquired with Nalcor on the reason for the increase in operating and maintenance costs on Muskrat Falls in 2017 and considered whether this would have impacted the decision if operating costs in the CPW were understated.

2.1.22 Findings/Observations - Operating and Maintenance Cost

In relation to the Operating and Maintenance Cost on the MFG facility and the LIL, we noted that the costs used in the power purchase model and the cost of service model was consistent with those noted in the table above. However, as noted above, the projected Operating and Maintenance costs for Muskrat Falls were re-evaluated in 2017 and found to be understated at that time.

We asked Nalcor the following question in relation to the increase in operating costs announced by Stan Marshall in 2017, to determine the potential impact at the time of sanction:

"In reference to a presentation on June 23, it notes on slide 14 that annual O&M costs were adjusted from $34 million to $109 million to be consistent with the industry standard of $100 million. Based on this, please confirm that O&M costs were understated in the CPW analysis at the time of sanctioning and if so, what was the cause of the understatement. In addition, please provide the approximate impact on the CPW analysis (i.e. if O&M was adjusted to industry standard at that time)."[162]

Nalcor's response stated that the cost estimate at sanctioning was based on the information available and the operating philosophy for the LCP assets established at the time. They noted that "the update to the operating and maintenance cost in June 2017 increased because of a reassessment of the basis of estimate, and considered the following:

- *"Current industry benchmarks relating to operating and maintenance costs as a percent of installed asset base and HVdc staffing models;*
- *The decision in 2016 by Nalcor to create a functionally-separate Power Supply organization to manage non-regulated electricity assets independently of regulated Hydro assets;*
- *An evolution to an operating philosophy for the LCP assets to support a high degree of reliability and availability to island customers, given these assets will be the single largest source of capacity and energy to the island; and*
- *The knowledge obtained regarding the operating and maintenance requirements of the assets installed."*[163]

We have not calculated the impact to the CPW related to the increase in operating and maintenance costs from $34 million to $109 million.

2.1.23 Fuel

Fuel cost is a key input into the CPW analysis. The Isolated Island option uses fuel as an input for thermal power generation. Different types of fuel are used in the various thermal generation stations. More generating assets requiring fuel were needed for the Isolated Island option, resulting in higher fuel cost.

Nalcor engaged PIRA Energy Group (PIRA) to develop fuel price forecasts. PIRA is an international energy consulting firm based in New York which provides analysis and price forecasting services for world energy prices. PIRA was founded in 1976 known for its comprehensive and detailed research and market analysis

[161] Nalcor Energy - Muskrat Falls Project Update – June 23, 2017
[162] Nalcor Energy - Response to Grant Thornton Question 7.1 – June 5, 2018
[163] Nalcor Energy - Response to Grant Thornton Question 7.1 – June 5, 2018

of energy markets. PIRA's clientele includes all of the world's major private integrated oil companies, and over 80% of both the oil producers and oil refiners in North America. PIRA provides services to over 80% of the U.S. gas and electric companies and over 90% of the gas and power marketers.[164,] S&P Global Platts acquired PIRA in August 2016.[165]

Fuel cost was estimated using the May 2012 PIRA forecast from 2012 to 2030 and subsequently increased fuel price estimates 2.0% per year, compounded until 2067. [166] The May 2012 PIRA forecast includes four price classifications of each type of fuel referred to as Low, Reference, High, and Expected Value. Nalcor used the Reference price in their fuel forecast.

Nalcor engaged Westney, a global provider of project risk management consulting services, to provide an expert opinion on which of the PIRA forecasts was most reasonable for use in the CPW calculations.[167]

Strategist develops generation expansion plans using generation sources (i.e.: thermal, hydraulic, and other) to optimize the least cost scenario and fulfil the total island energy requirements and electricity demands. The fuel volumes determined by Strategist based on energy production from thermal sources are multiplied by a conversion ratio approved to determine the amount of fuel required over the total load forecast period.

2.1.24 Procedures - Fuel

We performed the following procedures:

- Determined if the use of PIRA was consistent with other public utilities and determine if other fuel forecast sources were consistent with the PIRA forecast used;
- Determined how Nalcor applied the PIRA forecast; and
- Reviewed the expert opinion prepared by Westney Consulting regarding fuel price forecasts.

2.1.25 Findings/Observations - Fuel

PIRA methodology

We are aware that PIRA has been accepted as a source to forecast fuel in past hearings with the P.U.B as well as other regulators in Canada (for example; the NSUARB and the British Columbia Utilities Commission).

We also compared applicable fuel prices to prices in the 2011 EIA Annual Energy Outlook forecast[168] and observed that prices used in the CPW model trended consistently with the EIA Annual Energy Outlook 2011, with the following exceptions:

- No.2 Diesel prices were forecasted to grow at a higher rate after 2030 (2.23%) per the EIA vs 2.0% per CPW Model.
- No.6 (0.7%s) prices were forecasted to increase at a lower rate per the EIA after 2030 (average of 0.415% from 2030-2035) compared to approximately 2% annual growth per CPW
- No.6 (2.2%s) prices were forecasted to increase at a lower rate per the EIA after 2030 (CAGR of 0.474% from 2030-2035) compared to 2% per CPW.

[164] NAL0018683 - PIRA Price Forecast Methodology and Assessment of Future Oil Price Trends - October 26, 2012
[165] S&P Global Platts – S&P Global Platts Acquires PIRA Energy Group - August 4, 2016
[166] NAL0018691 – MHI Review of Muskrat Falls and Labrador Island HVdc Link and the Isolated Island Options – October 2012
[167] NAL0309572 – Work Task Order, Lower Churchill Project – July 12, 2012
[168] U.S. Energy Information Administration – Annual Energy Outlook 2011 with Projections 2035 – October 2011

Grant Thornton performed a sensitivity analysis to assess the impact of a reduced or eliminated assumed growth rates beyond the PIRA forecast period. The results of our analysis are set out in the table below:

CPW Impacts Based on Fuel Price Growth Assumptions After 2030 (amount in $000's)				
Fuel assumptions	**CPW – Infeed**	**CPW – Isolated**	**Difference**	**Impact vs Nalcor's case**
Nalcor's case	8,365,997	10,778,339	(2,412,342)	-
No increase in fuel prices after 2030	8,359,294	9,913,785	(1,554,491)	857,851
1% Increase in fuel prices after 2030	8,362,279	10,302,945	(1,940,666)	471,676

Grant Thornton reviewed the methodology used to determine the fuel volumes used in the forecast based on power demand requirements and concluded that this methodology is consistent with other public utilities.

Grant Thornton requested and reviewed the expert report received from Westney Consulting on the fuel price forecasts. The following is an extract of the Westney report on the high, low, expected and reference oil price forecasts issued by PIRA from the perspective of appropriate risk allocation for the DG3 decision:

"In our Opinion, the Expected Value price forecast is the one that represents the most reasonable choice for Nalcor at Decision Gate 3. We understand Nalcor's CPW analysis require forecasting the price of oil for the next 50 years. Since the Expected Value price forecast represents the full range of outcomes, we consider it to be a more appropriate basis for predicting outcomes over this long time horizon than one based on a specific scenario. Moreover, since it is analogous to the mean value of the oil price probability distribution, it is likely that it will more closely track actual prices than the Reference price forecast will. As a result, as the years go by, actual outcomes are more likely to cluster around the Expected Value price forecast than around the Low, Reference, or High price forecasts. Finally, we note that the use of the Expected Value price forecast is consistent with our experience with a variety of clients and conditions." [169]

We note that Nalcor utilized the Reference price forecast. Per MHI's January 2012 report, if they had utilized Expected Value, the Isolated Island option would have been higher.[170] We do note that in the years following sanctioning fuel prices decreased significantly, however, our analysis was completed without using hindsight.

2.1.26 Power Purchases

Power purchases are significantly higher under the Interconnected Island option due to the fact the capital cost estimates for Muskrat Falls Generation, LTA and the LIL are incorporated here through the use of Power Purchases Agreements and a Cost of Service ("COS") model. The operating and maintenance costs on these assets are also incorporated in the Power Purchase Agreements and Cost of Service model.

2.1.27 Interconnected Island Option - Labrador-Island Transmission Link

The CPW model at DG3 included $2.19 billion power purchases related to the LIL. This $2.19 billion is determined using a COS pricing model which calculates the cost recovery for the LIL capital costs.[171]

Nalcor defines COS as: "The total amount of money, including return on invested capital, operation and maintenance costs, administrative costs, taxes and depreciation expense, to produce a utility service."[172]

The COS model is a regulatory accounting mechanism for the recovery of fixed costs through depreciation as well as a return-on-rate base. The result of a COS model is ratepayers pay higher rates in the early years based on the undepreciated net book value of the assets plus a return on rate base of 7%.

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[169] Nalcor Energy – Response to Grant Thornton Request S.54
[170] NAL0018917 - Manitoba Hydro – Report on Two Generation Expansion Alternatives for the Island Interconnected Electrical System, Volume 2: Studies - January 2012
[171] NAL0018691 – MHI Review of Muskrat Falls and Labrador Island HVdc Link and the Isolated Island Options – October 2012
[172] NAL0019056- Nalcor's Submission to the Board of Commissioners of Public Utilities with respect to the Reference from the Lieutenant-Governor in Council on the Muskrat Falls Project, Volume 1 - November 10, 2011

2.1.28 Interconnected Island Option – Muskrat Falls Generation and Labrador Transmission Assets

The CPW model included $3.53 billion of power purchases for the MFG and the LTA. The capital costs for MFG and LTA have been included in the CPW model by incorporating a rate charged to ratepayers that is required for Nalcor to recover the capital costs of the Interconnected Island Option through a power purchase agreement model.[173]

Nalcor defines Power Purchase Agreement (PPA) as: "a Bilateral wholesale or retail power contract."[174] Under the PPA approach, rates remain fixed in constant dollars over the life of the project, escalating at a pre-determined rate approximating inflation.[175]

As outlined in MHI October 2012 Report, the CPW for the Muskrat Falls Generation facility and the Labrador Transmission Assets is derived using a PPA approach *"…whereby NLH will sign a take-or-pay contract with Nalcor with the expectation that Nalcor will receive its pre-determined revenue over the life of the asset based on the volumes of energy delivered."* [176] If any power is generated by Muskrat Falls in excess to the needs of Newfoundland and Labrador Hydro, the revenue will accrue to Nalcor.

To derive an appropriate price for NLH's power purchase requirements for the island, Nalcor undertook a supply pricing analysis for Muskrat Falls initially assuming that the total firm annual plant production was available for sale. The objective of this analysis was to determine the economic price for the project, in this instance expressed as an "escalating supply price". The escalating supply price is the price per MWh that recovers all costs associated with the Muskrat Falls hydroelectric development – operating and other incurred costs over time, debt service costs for the debt portion of the capital investment (as applicable) and a hurdle return on the equity portion of the capital investment.

The unit PPA rate was determined assuming an Internal Rate of Return ("IRR") of 8.4% based on a debt to equity ratio of 65% debt and 35% equity. This resulted in a proposed PPA unit rate of $65.38/MWh expressed in 2010 dollars.[177] This PPA rate was then escalated by 2% per year over the period under review.

2.1.29 Interconnected Island Option – Other

In addition to the amounts included in the Power Purchases section of the CPW model for MFG, LTA and LIL, there is also approximately $682.6 million which relates to power purchased from non-utility generators.[178]

2.1.30 Isolated Island Option – Other

The Isolated Island CPW model includes $763.8 million related to power purchases. This amount relates to power purchased from non-utility generators, in addition to the power generated by the existing Holyrood facility and the additional assets to be added (i.e. Wind, Hydro, CT and CCCT).[179]

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[173] NAL0018691 – MHI Review of Muskrat Falls and Labrador Island HVdc Link and the Isolated Island Options – October 2012

[174] NAL0019056 - Nalcor's Submission to the Board of Commissioners of Public Utilities with respect to the Reference fro129m the Lieutenant-Governor in Council on the Muskrat Falls Project - November 10, 2011

[175] NAL0019055 - Nalcor's Final Submission to the Board of Commissioners of Public Utilities with respect to the Reference from the Lieutenant-Governor in Council on the Muskrat Falls Project, March 2, 2012

[176] NAL0018691 – MHI Review of Muskrat Falls and Labrador Island HVdc Link and the Isolated Island Options – October 2012

[177] NAL0018691 – MHI Review of Muskrat Falls and Labrador Island HVdc Link and the Isolated Island Options – October 2012

[178] NAL0018691 – MHI Review of Muskrat Falls and Labrador Island HVdc Link and the Isolated Island Options – October 2012

[179] NAL0018691 – MHI Review of Muskrat Falls and Labrador Island HVdc Link and the Isolated Island Options – October 2012

2.1.31 Overall

The annual power purchase expense incurred by NLH under both the existing and future PPAs that have been included in Strategist to calculate the CPW are summarized in the following table[180]:

PPA	GWh per Year	End Date	Comment
Fermeuse Wind	84	2028	Re-investment by NLH assumed if Isolated Alternative
St. Lawrence Wind	105	2028	Re-investment by NLH assumed if Isolated Alternative
3rd Wind Farm	88	2034	Isolated Alternative only. NLH re-investment assumed
Corner Brook Co-Gen	65	2023	
Rattle Brook (hydro)	14	Continuous	
Star Lake (hydro)	144	Continuous	
Exploits Partnership (hydro)	137	Continuous	
Exploits Generation (hydro)	480	Continuous	
Muskrat Falls	Max 4.9 TWh	Continuous	

2.1.32 Procedures – Power Purchases

Grant Thornton performed the following procedures:

- Requested and reviewed the financial models for the power purchase and cost of service models included in the CPW; and
- Reconciled the capital costs of $6.2 billion, from the capital cost section of the report, to the power purchase and COS models.

Grant Thornton received:

- COS model in support of the LIL power purchase cost of $2.19 billion; and
- Power Purchase model in support of the MFG and LTA power purchase cost of $3.53 billion.

Grant Thornton noted that the capital costs incorporated in the COS model agreed with those outlined in the Capital Cost section of this report. Grant Thornton also agreed the outputs from the COS model to the CPW model for the Interconnected Island Option.

Grant Thornton noted that the capital costs incorporated in the power purchase model agreed with those outlined in the Capital Cost section of this report. Grant Thornton also agreed the outputs from the power purchase model to the CPW model for the Interconnected Island Option.

2.1.33 Capital Cost Estimates

The capital cost estimate for the Interconnected Island Option is discussed in detail in the Capital Cost Estimate section of this report. As outlined above, these capital costs are incorporated into the CPW analysis through the power purchases.

[180] NAL0019056 - Nalcor's Submission to the Board of Commissioners of Public Utilities with respect to the Reference from the Lieutenant-Governor in Council on the Muskrat Falls Project - November 10, 2011

As noted in the Capital Cost Estimate section of this report, strategic risks were quantified and incorporated into a management reserve, which was not included in the capital cost estimate and was not included in the CPW analysis. The management reserve, estimated at P50, was $500 million.

In addition to the management reserve, the contingency, estimated at P50, was $368 million, which was included in the CPW.

Choosing a higher contingency value of P75 or P90 would have been consistent with best practice for mega-projects. As outlined in a project team presentation, at DG3, using a P75 for contingency and strategic risks would have resulted in a capital cost estimate of approximately $7.5 billion.

2.1.34 Discount Rate

Included in the CPW analysis at DG3, Nalcor discounted the total costs for each option using a discount rate of 7.0%.

Nalcor applied the Weight Average Cost of Capital ("WACC") method in determining a discount rate for the CPW model as of January 2012. The same methodology and discount rate was applied to both the Interconnected Island Option and the Isolated Island Option. In the CPW Model, Nalcor used the same rate for both the discount rate and the Return on Rate Base ("RORB") under both Options.

Grant Thornton performed the following procedures:

- Reviewed external consultant opinions that Nalcor received on the discount rate; and
- Reviewed the WACC calculation utilized in the determination of the discount rate.

2.1.35 Findings/Observations – Discount Rate

In the MHI January 2012 Report, MHI performed Sensitivity Analysis on the discount rate.[181] MHI recognized that the choice of an appropriate discount rate may impact the results of the CPW analysis if there are significant differences in both the timing and scale of cost flows. MHI reviewed varying discount rates and ascertained that the choice of the discount rate within a reasonably close band does not substantially affect the CPW values.

Grant Thornton noted that the discount rate decreased from 8% at DG2 to 7% at DG3. We inquired of Nalcor the reason for this decrease. In response, Nalcor provided the following summary showing which components of the weighted average cost of capital change from 2010 to 2012.[182]

	January 2012	January 2010
Long Term Debt Cost		
Conference Board Long Term Government of Canada (GOC) Rate	4.83%	5.68%
Historical Spread for NLH Credit Over GOC	0.90%	0.67%
Forecast of NLH Long Term Cost of Debt	5.73%	6.35%
Debt Guarantee Fee Paid by NLH to Government	0.50%	1.00%
Average NLH Long Term Marginal Cost of Debt (Rounded)	**6.25%**	**7.35%**
Long Term Equity Cost		
Investor Owned Utility Long Term Opportunity Cost of Equity (Rounded)	**9.25%**	**10.00%**
Weighted Cost of Capital (WACC)		
Average of 75:25 Debt:Equity Splits	**7.00%**	**8.01%**

[181] NAL0018917 - Manitoba Hydro – Report on Two Generation Expansion Alternatives for the Island Interconnected Electrical System, Volume 2: Studies - January 2012
[182] Nalcor Energy - Response to Grant Thornton Question 9.5 – July 4, 2018

Other inputs included in the CPW calculation were as follows:

- Allowance for funds used during construction and interest during construction;
- Escalation;
- Transmission losses;
- Asset maintenance schedule;
- Forced outage rates;
- Thermal heat rates; and
- Environmental externalities

Grant Thornton reviewed each of the above inputs and noted that they have less significant impact on the CPW calculation. We performed the following procedures related to these inputs:

- Reviewed the CPW model and the applicable input into the model;
- Where applicable, review Nalcor's outside expert reports; and
- Recalculated certain outputs.

There were no exceptions to note that would have impacted the Interconnected Island Option as the least-cost option.

2.1.36 Sensitivity Analysis Performed by Nalcor

Nalcor, with the help of its external consultants, performed a number of sensitivities on the CPW inputs at both DG2 and DG3.

At DG2, sensitivities completed are shown in the following summary:[183]

Summary of Sensitivities at Decision Gate 2			
CPW ($ millions)	**Isolated Island**	**Interconnected Island**	**Difference**
Base case	8,810	6,652	2,158
Annual load decreased by 880GWh	6,625	6,217	408
Fuel costs: PIRA's low price forecast	6,221	6,100	120
Fuel costs: PIRA's high price forecast	12,822	7,348	5,474
Fuel costs: PIRA May 2011 update for Reference Oil Price Forecast	9,695	6,889	2,806
Fuel price reduced by 44% from base case	6,134	6,134	-
Moderate Conservation (375GWh by 2031)	8,363	6,652	1,711
Aggressive Conservation (750GWh by 2031)	7,935	6,652	1,283
Loss of 880 GWh 2013 forward	6,625	6,625	-
Low Load Growth (50% of 2010 PLF post Vale)	7,380	6,628	752
200MW Additional Wind (100MW in 2025 and 100MW in 2035)	8,369	6,652	1,717
MF and LIL Capital Cost +20% & Fuel Cost Reduced by 20%	7,600	7,217	383
MF and LIL Capital Cost +25%	8,810	7,627	1,183
MF and LIL Capital Cost +50%	8,810	8,616	194
Labrador-Island Link capital cost increased by 25%	8,810	7,050	1,760
Muskrat Falls GS capital cost increased by 25%	8,810	7,229	1,581
Federal Loan Guarantee	8,810	6,052	2,758
Holyrood to 2041, then CF at Market Price	7,935	6,652	1,283
Carbon Pricing on Fossil Fuel	9,324	6,669	2,655
CF Energy Post 2067 at Market Rates Instead of Cost	8,810	6,664	2,146
Scenario with: **- Fuel cost decreased 20%** **- Annual load growth decrease of 20%** **- Capital cost increased for MF and LIL by 20%**	7,037	6,878	159
Scenario with: **- Annual load decreased by 880GWh** **- MF and LIL capital cost increased by 10%**	6,625	6,598	27

[183] NAL0018916 - Report on Two Generation Expansion Alternatives for the Island Interconnected Electrical System Volume 1: Summary of Reviews, January 2012
NAL0019056 - Nalcor's Submission to the Board of Commissioners of Public Utilities with respect to the Reference from the Lieutenant-Governor in Council on the Muskrat Falls Project - November 10, 2011

The below table summarizes the sensitivity analysis performed by Nalcor at DG3[184]:

Summary of Sensitivities at Decision Gate 3			
CPW ($ millions)	**Isolated Island**	**Interconnected Island**	**Difference**
Base case	10,778	8,366	2,412
PIRA Fuel Price - Expected	11,391	8,376	3,015
PIRA Fuel Price - Low	8,584	8,000	584
PIRA Fuel Price - High	15,435	8,836	6,598
Increase Capex 10%	11,034	8,882	2,152
Increase Capex 25%	11,417	9,654	1,763
Decrease Capex 10%	10,523	7,837	2,686
Increase Interest Rate 50 bps	10,863	8,604	2,259
Increase Interest Rate 100 bps	10,947	8,851	2,096
Decrease Interest Rate 25 bps	10,736	8,250	2,486
Carbon Pricing commencing 2020	11,360	8,368	2,992

2.1.37 Procedures and Findings

Grant Thornton reviewed the sensitivity analysis completed at DG2 and DG3 and noted the following:

- There were more sensitivity analysis completed at DG2;
- Included in the DG3 sensitivity analysis, there were specific sensitivity analysis completed related to increases to capex, for example 25%; however, when increasing capex by 25%, both the Interconnected Island Option and Isolated Island Option was impacted, which decreased the overall difference. The risk associated with the capex on the Interconnected island option would be higher than the risk associated with the capex on the isolated island option, due to the projects size and length;
- From DG2 to DG3, there was an increase to the capital costs related to the Interconnected Island Option. The capital costs are the most significant input to the Interconnected Island Option and was a known risk in the overall analysis. However, at DG3, there was not a sensitivity analysis completed on capex related to the Interconnected island option only; and more specifically, there was not a sensitivity analysis that showed the impact of capex to the ranges outlined in the Association for Advancement to Cost Engineering (“AACE”) standards for a Class 3 estimate, as discussed in the capital cost section;
- From DG2 to DG3, there was an increase to the load forecast used under both the Interconnected Island Option and the Isolated Island Option. The accuracy of the load forecast is a known risk in the overall analysis. However, at DG3, there was not a sensitivity analysis completed on the load forecast to show the potential impact of a change in the load forecast on the overall analysis; and
- The DG3 sensitivity analysis did not show a scenario where fuel prices decreased and capital cost increased.

[184] NAL0018691 – MHI Review of Muskrat Falls and Labrador Island HVdc Link and the Isolated Island Options – October 2012

3.1 Capital Cost Estimates

Nalcor determined the capital cost estimates for the Interconnected Island Option and Isolated Island Option with the assistance of external experts, including SNC Lavalin ("SNC"). Capital cost estimates are key inputs into the CPW analysis, which Nalcor applied in order to determine the least-cost option. The impact on the CPW is discussed in further detail in that respective section of the report.

3.2 Interconnected Island Option

CCE for the Interconnected Island Option includes three major construction pieces as follows:

1 MFG

2 LTA

3 LIL

The CCE was calculated by adding to the Base Estimate the Estimate Contingency and Escalation Allowance. Each of the aforementioned terms are defined in the below bar chart[185].

Project Estimate	**Escalation Allowance**	Provision for changes in price levels driven by economic conditions, including inflation. Estimated using economic indices weighted against base estimate components.
	Estimate Contingency	Provision made for variations to the basis of an estimate of time or cost that are likely to occur, that cannot be specifically identified at the time the estimate is prepared but, experience shows, will likely occur. It is not meant to cover scope changes outside the Projects' parameters (i.e. events such as strikes of natural disasters, escalation or foreign currency impact), or changes that alter the basis upon which the control point for management of change has been established (e.g. basis of design, project execution plan).
	Base Estimate	Reflects most likely costs for known and defined scope associated with project's specifications and execution plan as produced by the estimator.

While SNC prepared approximately 70% of the base estimate, they were not asked to calculate the contingency and the escalation allowance. Nalcor engaged other experts to provide input into the calculation of the provision for contingency and escalation.

[185] NAL0019634 - Decision Gate 3 Capital Cost Estimate – December 11, 2012

At sanction (December 2012), the CCE was calculated to be $6.2 billion as shown in the table below[186]. The $6.2 billion consist of $5.47 billion base estimate, $370 million contingency and $360 million of escalation allowance.

($ millions)	Muskrat Falls	LTA	LIL	Total
Base Estimate	$ 2,512	$ 601	$ 2,360	$ 5,473
Growth Allowance = Estimate Contingency + Escalation Allowance	$ 389	$ 90	$ 250	$ 729
Total	**$2,901**	**$ 691**	**$ 2,610**	**$ 6,202**

3.2.1 Base Estimate

The total estimate was separated into approximately 150 work packages, each one being assigned a work package number.

To determine the base estimate, Nalcor adopted the AACE's recommended estimating practices. At the time the base estimate was prepared, the AACE had not published a classification system for hydro or transmission projects. Accordingly, Nalcor followed the general guidance in AACE 17R-97[187] to determine the level of estimate maturity at sanctioning.

The following table is an extract from 17R-97 illustrating classification of a project[188]:

	Primary Characteristic	*Secondary Characteristic*			
ESTIMATE CLASS	**MATURITY LEVEL OF PROJECT DEFINITION DELIVERABLES** Expressed as % of complete definition	**END USAGE** Typical purpose of estimate	**METHODOLOGY** Typical estimating method	**EXPECTED ACCURACY RANGE** Typical +/- range relative to index of 1 (i.e. Class 1 estimate) [a]	**PREPARATION EFFORT** Typical degree of effort relative to least cost index of 1 [b]
Class 5	0% to 2%	Screening or feasibility	Stochastic (factors and/or models) or judgment	4 to 20	1
Class 4	1% to 15%	Concept study or feasibility	Primarily stochastic	3 to 12	2 to 4
Class 3	10% to 40%	Budget authorization or control	Mixed but primarily stochastic	2 to 6	3 to 10
Class 2	30% to 75%	Control or bid/tender	Primarily deterministic	1 to 3	5 to 20
Class 1	65% to 100%	Check estimate or bid/tender	Deterministic	1	10 to 100

Notes: [a] If the range index value of "1" represents +10/-5%, then an index value of 10 represents +100/-50%.
[b] If the cost index value of "1" represents 0.005% of project costs, then an index value of 100 represents 0.5%.

[186] NAL0019634 - Decision Gate 3 Capital Cost Estimate – December 11, 2012
[187] AACE International - Recommended Practice No. 17R-97 Cost Estimate Classification System - November 29, 2011
[188] AACE International - Recommended Practice No. 17R-97 Cost Estimate Classification System - November 29, 2011

When the project was sanctioned in December 2012, the estimate was classified by Nalcor as an AACE Class 3 estimate, which required a project definition (which is the percent of engineering completed at a point in time) of 10-40%. The project definition at sanctioning was considered 53% complete.[189]

For a Class 3 estimate, AACE refers to an expected estimate accuracy range with a low end of -10% to -20% and high end of +10% to +30% (-20% to +30%).

As per Nalcor's DG3 Capital Cost and Schedule Estimate Summary Report, when referring to the recommended contingency results it states that "Interpretation of these results indicates that the entire Base Estimate has an overall accuracy (P10/90) in the range of -12% to +13%, which is well within the expectations of the targeted Class 3 estimate for a DG3."[190]

Nalcor engaged SNC as the Engineering, Procurement and Construction Management ("EPCM") contractor specifically for their experience in hydro-electric projects. SNC's engineers were involved in the design of the project and their estimating team completed approximately 70% of the base estimate. SNC engineers determined material quantities required for each work package and provided quantity tables to the SNC estimating team, which was led by SNC's Lead Estimator.[191] Labour productivity hours were estimated based upon normal working conditions and then they were increased by an additional 20% to account for the lack of skilled labour in 2012 and potential reductions in productivity due to weather and other circumstances. According to SNC's Lead Estimator the total labour hours estimated for the project was initially 12.6 million and then an additional 2.5 million hours were added to that which represented the additional 20%. We understand that Nalcor developed mitigation plans to address labour productivity.

Before sanctioning Nalcor engaged external consultants, for example Validation Estimating to review the estimate and other consultants to perform check estimates. The check estimates were completed for the Muskrat Falls civil and concrete works and compared against the primary estimate completed by SNC. The check estimators were provided with the same quantities, construction schedule and labour rates used by SNC. They were each left to determine the appropriate production rates, fleet rates and construction methodology to incorporate into the estimate.[192] The DG3 Basis of Estimate document stated, "all three (3) estimates were within very close proximity, thus confirming the estimate being prepared by the SLI estimators."[193]

Validation Estimating (one of the external experts) was engaged in 2012 to complete a qualitative review of the estimate and provide assurance of whether the following objectives were being met:

1 The estimate meets industry requirements for an AACE International Class 3 estimate;

2 The estimate serves as a basis for Gate 3 decision economic evaluations; and

3 The estimate serves as a basis for control budgeting of the next phase (i.e. construction).

3.2.2 Procedures – Base Estimate

The procedures we performed in reviewing the base estimate included:

1 Reviewed various Nalcor documents defining and explaining the estimating processes;

2 Reviewed reports completed by third party experts (i.e. MHI October 2012 Report); and

3 Performed interviews of individuals involved in the preparation, review and communication of the estimate.

3.2.3 Findings and Observations - Base Estimate

MHI reviewed Nalcor's analysis of the Interconnected Island Option in October 2012. The report discussed the capital cost estimate for the Interconnected Island Option at DG3, and stated that *"based on the amount*

[189] NAL0000197 - Lower Churchill Project Phase 1- Decision Gate 3 Support Package
[190] NAL0020620 - Decision Gate 3 Capital Cost and Schedule Estimate Summary Report - October 2012
[191] Interview Summary - SNC's Lead Estimator – April 10 and May 8, 2018
[192] NAL0019570 – Decision Gate 3 Basis of Estimate - December 3, 2012
[193] NAL0019570 - Decision Gate 3 Basis of Estimate - December 3, 2012

of engineering and levels of costs provided, MHI considers the decision gate 3 cost estimate to be an AACE class 3 estimate and therefore would be considered reasonable for the decision gate 3 project sanction stage."[194]

A quote from Validation Estimating has been referenced in a number of Nalcor documents:

"the LCP Gate 3 estimate in its current state is one of the best mega-project "base" estimates that this reviewer has seen in some time."[195]

Grant Thornton interviewed a representative of Validation Estimating on May 23, 2018 and confirmed that:

"the base estimate that he reviewed seemed to be very good quality and the estimate did line up with a class 3 estimate, but it was the risk that was questionable".

There are other points to note in addition to the above. They are as follows:

- The contingency included in the base estimate was only a portion of the total contingency calculated. See the contingency section for a further explanation; and
- The contingency that was included in the base estimate was calculated under the assumption that there was a 50% chance that cost overruns would occur, an aggressive assumption by Nalcor. See the contingency section for a further explanation.

3.2.4 Estimate Contingency

Contingency is a provision made for changes in the base estimate for time or cost that are likely to occur, but cannot be specifically identified at the time the estimate is prepared.[196] Nalcor's categorized risks associated with the contingency in two categories, Tactical and Strategic.

The contingency amount associated with Tactical Risks were included in the capital cost estimate. Tactical risks are associated with the base capital cost estimate as a result of uncertainty with the four components of the estimate:

- Project definition and scope admission
- Construction methodology and schedule
- Performance factors
- Price (excluding escalation)

Strategic risks were considered management reserve and this contingency amount was excluded from the capital cost estimate. Strategic risk is exposure predominantly driven by three key areas, all of which are linked to labour availability and productivity. These areas are as follows:

- Performance Risk Exposure
- Competition for Resources
- Schedule Risk Exposure

Exposure related to strategic risks would be held in a Management Reserve. Management reserve is an amount required to be held and be controlled by the Shareholder with the Gatekeeper, that is used to provide a higher confidence cost level (i.e. comfort factor), including the handling of the impact of any materialization of strategic risks.[197]

In Nalcor's risk assessment process they identified a number of risks that were associated with environmental impacts, including those which were identified in the Joint Review Panel of environmental

[194] NAL0018691 - Review of the Muskrat Falls and Labrador Island HVdc Link and the Isolated Island Options by Manitoba Hydro International, Page 55
[195] Validation Estimating - Review of Lower Churchill Project Gate 3 Capital Cost Estimate – April 2012
[196] NAL0019634 - Decision Gate 3 Capital Cost Estimate – December 11, 2012
[197] NAL0020664 – Decision Gate 3 Project Cost and Schedule Risk Analysis Report - October 1, 2012

impacts of the Lower Churchill Hydroelectric Generation Project. Nalcor has provided us with documentation regarding their assessment, quantification and mitigation plans related to these risks.

3.2.5 External Experts

To calculate the contingency amounts, Nalcor held risk workshops over a two day period in May of 2012. The subject of these workshops was the discussion of tactical and key project risk and the dollar range of the potential impact of these risks. In the "Gate 2 Project Risk Analysis" it states Nalcor Energy LCP ("NE-LCP") *"met with Westney consultants to discuss the Best and Worst Case ranges around the estimate for each cost category. The final ranging was performed by the NE-LCP, but it was vetted and questioned by the Westney participants. Westney had selected the probability distributions to use with the ranged data and ran the Monte Carlo simulation."*[198] As well, Nalcor's Decision Gate 3 Project Cost and Schedule Risk Analysis Report states *"Project team members developed best and worst cases for each of the estimate items considering all identified risks around the estimate. The best and worst case values were used to develop probability distributions consistent with each items risk profile."*[199] Based on this we concluded that Nalcor was responsible for selecting the risk ranges (with input from Westney) and Westney was responsible for using those ranges to provide a range of potential outcomes from their Monte Carlo simulation. Westney performed a Monte Carlo simulation to calculate the range of dollar exposure for each of the tactical and strategic risks. Based on the results of the Monte-Carlo simulation a P-factor is selected to determine the probability that that cost overruns or underruns will occur.

For example, a P50 means there is a 50% chance that overruns will occur and 50% chance that the cost will be the amount estimated or less. A P75 means there is a 25% change that overruns will occur or a 75% chance that the cost will be the amount estimated or less. The higher the P factor, the greater the contingency amount.

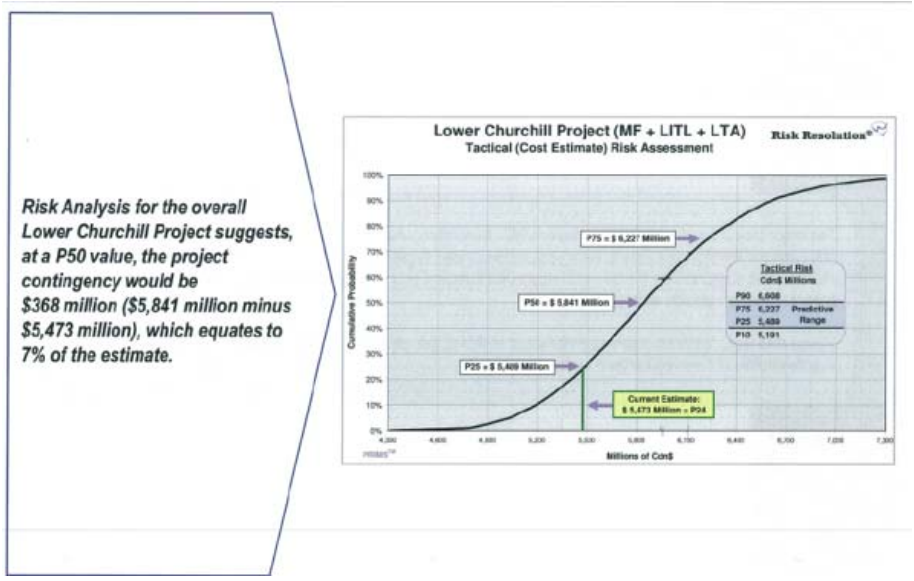

Image taken from NAL0020664 - Decision Gate 3 Project Cost and Schedule Risk Analysis Report

Nalcor selected the P50 value from the Monte Carlo results, meaning that the actual total cost of the project had a 50% likelihood of costing more or less then the value provided.

[198] NAL0020663 – Gate 2 Project Risk Analysis - September 15, 2011
[199] NAL0020664 – Decision Gate 3 Project Cost and Schedule Risk Analysis Report - October 1, 2012

Contingency at a P50 was calculated by subtracting the P50 value of $5,841 million and subtracting the base estimate of $5,473 million for a contingency value of $368 million. The contingency was allocated between MFG, LTA and the LIL as follows[200].

	Muskrat Falls	LTA	LIL	Total
Base Estimate	$ 2,511.9	$ 601.3	$ 2,359.6	$ 5,472.8
Historical Cost Adjustment	97.3	4.2	85.3	186.8
Future Expenditures	2,414.6	597.1	2,274.3	5,286.0
Recommended P50 Contingency	**226.7**	**54.8**	**86.5**	**368.0**
Contingency % of Future Expenditures	**9.4%**	**9.2%**	**3.8%**	**7.0%**

Note: All forward costs are noted in millions of January 2012 CDN $

Westney also calculated the strategic risk with a Monte Carlo simulation in order to calculate the probable range of the estimate, which was included in management reserve.

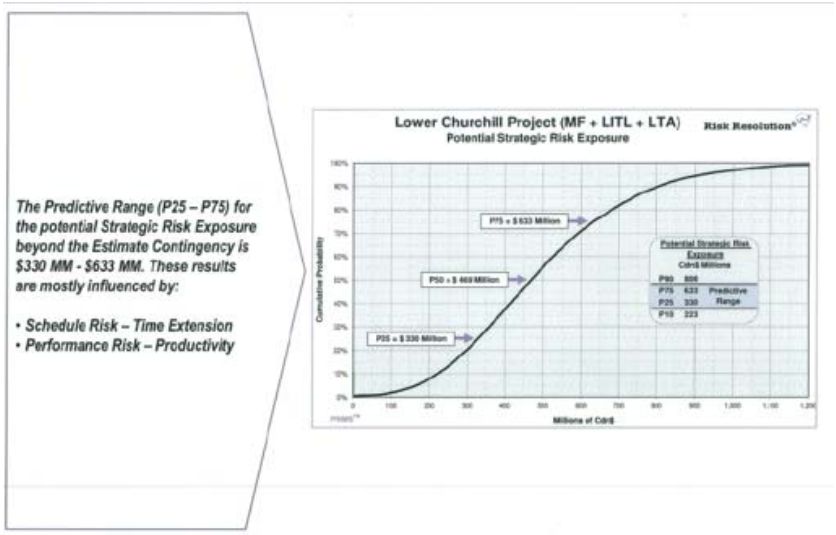

Image taken from NAL0020664 -Decision Gate 3 Project Cost and Schedule Risk Analysis Report

Nalcor selected the P50 value from the Monte Carlo results, which amounted to approximately $500 Million. This was included in contingent equity and did not form part of the capital cost estimate nor was it included in the CPW calculation.

[200] NAL0020664 - Decision Gate 3 Project Cost and Schedule Risk Analysis Report - October 1, 2012

3.2.6 Procedures

Grant Thornton procedures pertaining to the contingency included the following:

1. Reviewed various Nalcor and Westney Consulting documents that explained the process of calculating the contingency
2. Interviewed various consultants used by Nalcor including Validation Estimating and , representatives of Westney Consulting
3. Interviewed the Nalcor LCP Project Team (past and present)
4. Interviewed certain Nalcor Executives (past and present)

3.2.7 Findings and Observations

Risk ranges

Risk workshops were conducted in May 2012. For the identified risks, high and low dollar ranges were determined. According to Nalcor's response to Grant Thornton Question 8.2 "the evaluation and quantification of strategic risks was led by Nalcor's risk advisor, Westney Consulting Group…Westney then applied its risk resolution methodology…to quantify the strategic risks."[201]

However, in the DG3 Project Cost and Schedule Risk Analysis Report it states "Westney consultants met with the Nalcor project team to discuss the Best and Worst Case ranges around the estimate for each cost category…the final ranging was performed by Nalcor." The DG3 Project Cost and Schedule Risk Analysis Report also notes that "the scope of work for Westney Consulting Group was for Westney to guide and facilitate…this resulted in an outcome of the analysis that represented the best thinking and efforts of both the Nalcor Energy participants and the consultants from Westney."[202]

P factor

As mentioned above, the P50 value is essentially the 50th percentile of the Monte Carlo results. This means that the actual total cost could come in at 50% above or below the P50 value. AACE 42R-08[203] states that *"management can decide how much risk they are willing to accept and therefore how much contingency will be required".* Selecting the P50 value does not provide certainty that there will not be cost overruns. In order to be more certain that cost overruns will not occur, Nalcor could have chosen a P75 or a P90, meaning there would only be a 25% or 10% chance of overruns respectively, and therefore a 75% or 90% chance of no cost overrun.

Grant Thornton asked Validation Estimating if selecting a P50 value for contingency was in accordance with best practice. In response, Validation Estimating noted, *"P50 funding is a concept for portfolio - say you have a major company and you have 300 projects in your annual portfolio, if you fund them all at P50 level it means (half) 150 will be over and 150 will be under and your annual capital budget will be about right. It makes sense from a portfolio viewpoint but on a mega project where that one project is the company – the P50 is extremely aggressive. I don't know any company who will fund a single major project like that at P50. Most companies will fund it at a higher level – commonly P70 or P80."* [204] Validation Estimating also noted that Suncor used to fund at a P70 and the Department of Energy funds at a P90, and explained that somewhere between P70 and P90 would be best practice.[205]

With regards to the contingency value, Grant Thornton asked Validation Estimating how the contingency can be 7% on something so large and complex. Validation Estimating noted that "something is very wrong, it's driven by the management – what they want. If they had $300 million contingency that should have been a billion.[206]"

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[201] Nalcor Energy - Response to Grant Thornton Question 8.2 – July 3, 2018
[202] NAL0020664 – Decision Gate 3 Project Cost and Schedule Risk Analysis Report
[203] AACE International - Recommended Practice No. 42R-08 Risk Analysis and Contingency Determination Using Parametric Estimating - May 26, 2011
[204] Interview Summary - Validation Estimating - May 23, 2018
[205] Interview Summary - Validation Estimating - May 23, 2018
[206] Interview Summary – Validation Estimating - May 23, 2018

Grant Thornton also interviewed SNC employees who were involved with the LCP. Specifically, the Project Controls Manager and a Risk Director at SNC. Both stated that the SNC policy is to choose a P85 value. The Risk Director referred to a P50 as bad practice.[207]

Our third party expert, also noted that while selecting P50 as the confidence interval is within the AACE 42R-08 guidance, in their experience, they have typically observed their clients using P75 or above as the confidence level to provide a higher level of confidence that the estimated value will not be exceeded.

If Nalcor had chosen a higher confidence level such as the P75 of $6,227 million or the P90 of $6,608 million, it would have resulted in a contingency value of $754 million or $1,135 million respectively; increasing the total capital cost estimate by $386-767 million.[208]

Strategic Risks[209]

Strategic risks are defined as "identified background risks that are outside of the controllable scope of the project team, typically pertaining to external issues such as enterprise-level issues, governance, financial markets, stakeholders, hyperinflation, and regulatory approvals. Managing these risks requires significant effort and influence by the Gatekeeper with external stakeholders. Strategic risk is also referred to as the risk of failure of the general execution plan." As noted above, strategic exposure was predominantly driven by three key areas; competition for resources, performance risk exposure and schedule risk exposure.

Strategic Risk – Competition for Resources[210]

Competition for resources stems from the fact that the estimate was based on labour rates in the Hebron Agreement. Given that this was a project in progress in Newfoundland at the time, it was known that attracting experienced employees would be an issue and they would likely have to compete with Western Canada for labour.

Strategic Risk – Performance Risk[211]

Performance risk exposure relates to labour productivity, which can be impacted by a number of factors such as weather, location, etc. The DG3 Project Cost and Schedule Risk report notes that the rates used in the estimate and contingency were much better than what was currently being experienced in Long Harbour; a project ongoing in Newfoundland at the time.

[207] Interview Summary - SNC - April 10, 2018
[208] NAL0020664 – Decision Gate 3 Project Cost and Schedule Risk Analysis Report
[209] NAL0020664 – Decision Gate 3 Project Cost and Schedule Risk Analysis Report
[210] NAL0020664 – Decision Gate 3 Project Cost and Schedule Risk Analysis Report
[211] NAL0020664 - Decision Gate 3 Project Cost and Schedule Risk Analysis Report

Strategic Risk – Schedule Risk

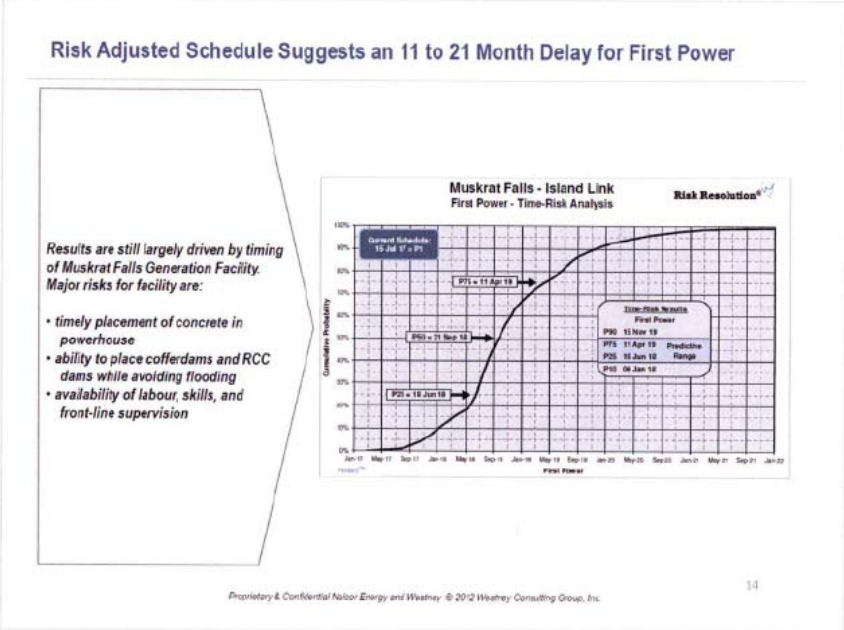
Schedule risk exposure refers to the potential time or schedule risk beyond the plan due to weather and volume of work in the power house as well as the risk of sustainability of the required production rates for placement of the concrete.[212] There were a number of factors known prior to sanction that increased the schedule risk. Each of the following factors have been discussed below.

- Prior to DG3, the release of the Environmental Assessment was delayed by 6 months;
- There were concerns that the concrete pour for the Astaldi work package CH0007 was aggressive; and
- It was known that the date for full power from Muskrat Falls was unlikely to be attained.

Prior to DG3, the environmental assessment that was expected to be released in August 2011 was delayed until March 2012, a seven month delay. The environmental assessment release was critical for Nalcor to obtain permits and legally begin construction on the Muskrat Falls Project. In April 2012, after the assessment was released, work began to prepare the south side access road. The April 2012 monthly progress report stated "Delay in start of South Side Access Road construction is having a 'knock on effect' for other early work packages." [213]

With regards to the concrete pour, the DG3 Project Cost and Schedule Risk Analysis Report includes an email from the SNC Lead Estimator to the Deputy General Project Manager regarding the schedule for the concrete pour. In the email, the SNC Lead Estimator summarized his opinion regarding the concrete pour schedule planned for work packaged CH0007, and stated that *"This is a quite aggressive schedule because of the huge quantities involved in a relatively short period of time and although the day/cycle ratio seems to me reasonable, the fact remains that, running at a pace of some 480m3/day, for almost three consecutive years, at every day, will remain quite a challenge! I suggest we put a time or money provision in our contingency plan, to overcome a possible failure that may occur."*[214]

During a presentation from the LCP Project Team we were shown the following:



[212] NAL0020664 - Decision Gate 3 Project Cost and Schedule Risk Analysis Report
[213] Muskrat Falls Project Summary of Pre-Sanction, Briefing Note as Requested by Nalcor Legal Counsel McInnes-Cooper, Page 35-36
[214] NAL0020664 - Decision Gate 3 Project Cost and Schedule Risk Analysis Report

Image taken from Muskrat Falls Project – The Sanction Decision – Briefing Note as Requested by Nalcor Legal Counsel McInnes-Cooper

The above image notes that July 15, 2017 schedule was a P1. This meant that there was a 99% chance that the schedule for first power would not be met. The LCP Project Team noted that *"there was a low probability that a mid-2017 First Power date would be met. As such, the PMT recommended to Nalcor Executive that a provisional schedule reserve allowance should be made to account for the difference between the target date and the probable date. Given the desire to achieve the best possible date, Nalcor Executive wanted to maintain the Target Milestone Schedule, and thus no schedule reserve allowance was made to accommodate the residual risk exposure identified in the QRA."*[215]

The schedule risk was essentially a known risk at this time and would likely be further impacted by the performance risks and competition for resources risks discussed previously. While it was quantified and included in the management reserve, this reserve was not part of the capital cost estimate and was excluded from the CPW calculation.

The draft report by Validation Estimating outlined that Nalcor referred to strategic risks as "failure of the general execution plan"; in relation to this, Validation Estimating's report stated that "This categorization is meaningful for who is responsible to be the risk owner and risk actionee, but it is irrelevant to contingency quantification; most of these risks have 100% probability of occurring and some money is expected to be spent (which is the definition of contingency). If there are uncertain balancing opportunities, explicitly include them in the analysis.[216]"

Although strategic risks were not included in the capital cost estimate at DG3, they were included in the project estimate at DG2. It was noted that this change was made during the negotiations with Emera Inc. Nalcor stated *"that it was required to respond to Emera's concern regarding its ability to sell the strategic risk concept to the Nova Scotia regulator, the Nova Scotia Utility and Review Board".*[217]

In the interview with Validation Estimating, we asked him whether risk associated with competition for resources included in strategic risk should have been included in the capital cost estimate. Validation Estimating explained that *"estimators were aware of the labour productivity problem."* Validation Estimating went on to say that *"…strategic risk will appear in every risk analysis in a mega project and yes it should be funded".* Further to this, we asked if you would get a skewed result if strategic risk wasn't included. In response, Validation Estimating stated that *"You would get a wrong result. I mean you don't not fund a risk that you have 100% probability of occurring. I put that in my report in 2012 – I was concerned that they were not including risks."*[218]

In a presentation on May 11, 2018, a former member of the LCP Project Team demonstrated that the DG3 estimate of $6.2 Billion would have been $7.5 Billion ($1.3 billion higher), after adjusting for identified strategic risks using a P75 rather than the P50 that was used to quantify the management reserve.[219] This was reiterated by the Project Team; they provided a binder of support for the sanction decision, in this binder it was stated "if the P75 recommendation from the 2012 Quantitative Risk Assessment ("QRA") had been selected as the sanction cost basis, the sanction basis would have been $7.5B".[220]

3.2.8 Escalation Allowance

Escalation is a provision for cost changes resulting from changes in price levels driven by underlying economic conditions; it includes the effects of inflation, but does not include foreign exchange. In 2008, prior

[215] Muskrat Falls Project – The Sanction Decision – Briefing Note as Requested by Nalcor Legal Counsel McInnes-Cooper

[216] Validation Estimating - Review of Lower Churchill Project Decision Gate 3 Capital Cost Estimate - April 2012

[217] Muskrat Falls Project Summary of Pre-Sanction, Briefing Note as Requested by Nalcor Legal Counsel McInnes-Cooper, Page 17

[218] Interview Summary – Validation Estimating – May 23, 2018

[219] Interview Summary – Former Nalcor Project Team - May 11, 2018

[220] Muskrat Falls Project The Sanction Decision, Briefing Note as Requested by Nalcor Legal Counsel McInnes-Cooper, Page 19

to DG2, Nalcor engaged Validation Estimating to help with developing a cost escalation model. Validation Estimating provided recommended best practices, and in accordance with AACE 58R-10, Nalcor developed a methodology for estimating cost escalation.

The escalation methodology was based on four underlying factors which affect escalation; the composition of expenditures (i.e. Escalation bins), the broader economic outlook and future expected cost escalation of various goods and services required, timing of the expenditures as determined by the project schedule, and the contracting strategy. In other words, the estimation of escalation involved identifying the periods of time when the costs were estimated to be incurred based on the project schedule. The costs were separated into categories called “escalation bins,” and each bin was applied and appropriate escalation rate based on price indices provided by Global Insight and Power Advocate. Escalation factors used were a weighted average of the expected price change based on the costs in each particular year and the expected change in costs for each escalation bin.

3.2.9 Procedures and Findings

The procedures Grant Thornton performed in reviewing escalation included the following:

1. Reviewing various Nalcor documents that explain the escalation process;
2. Reviewing the Validation Estimating presentation; and
3. Reviewing the escalation methodology to determine if it was in accordance with best practice and AACE standards.

In March 2009, Validation Estimating provided a presentation to Nalcor on their estimating process, which was used to develop their escalation methodology.

MHI also reviewed escalation included in the capital cost estimate and compared it to their own practices. MHI stated "*At Manitoba Hydro, escalation indices are then applied to the base estimate using the Global Insight data for the various project drivers (labour, equipment, commodities, fuel, etc.) which are specific for the hydro power products built in Manitoba. The escalation indices are modified to take into account regional economic activity. Nalcor's process is very similar to that used by Manitoba Hydro and is a utility best practice.*[221]

Grant Thornton's third party expert reviewed the escalation process. They found that Nalcor's process which involved identifying the periods when costs were expected to be incurred and calculating escalation based on this project schedule, separating the costs into escalation bins, and applying an escalation rate based on price indices provided by Global Insight and Power Advocate to each bin, was in accordance with best practice based on AACE standards as well as their experience in the industry.

During DG2, escalation was applied to the contingency value; however, in 2012 escalation was not calculated on the contingency. The AACE Recommended practice 58R-10[222] notes that since contingency is a fund of known risks that is to be spent during the project, escalation should be applied. Validation Estimating also noted in his interview "if they had $300 million contingency that should have been a billion – escalation is above that. You should have escalation on the contingency."[223]" It is not clear why Nalcor included this escalation on contingency at DG2 but not DG3 but it is not expected to be a material amount that would change the decision to sanction the Interconnected Island Option assuming all other things being equal.

In summary, escalation was prepared in accordance with best practice, aside from the fact it was not applied to contingency. While this is a finding, it is not expected to be material enough to change the decision all other things being equal.

[221] NAL0018916 - Manitoba Hydro International Report on Two Generation Expansion Alternatives for the Island Interconnected Electrical System, Volume 1: Summary of Reviews - January 2012, Page 36
[222] AACE International - Recommended Practice No. 58R-10 Escalation Estimating Principles and Methods Using Indices, - May 25, 2011
[223] Interview Summary – Validation Estimating- May 23, 2018, Page 14

Conclusion

Based on the procedures performed, we identified a number of factors which resulted in:

1. A potential overstatement of the CPW for the Isolated Island Option; and
2. A potential understatement of the CPW for the Interconnected Island Option.

The combination of these potential misstatements may have resulted in the Interconnected Island Option (the actual option selected by Nalcor) no longer being considered the least cost option at time of sanctioning.

Appendix A - Qualifications

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Scott I. Shaffer

CCA, CPA, CFE, MBA

Construction Advisory Services Practice Leader

Scott I. Shaffer is the co-leader of Grant Thornton's Construction Advisory Services Practice. Scott has conducted construction cost reviews working on behalf of owners involved in construction projects of all types. He is a former auditor, leading audit engagements for both commercial and residential builders. He has extensive experience in dealing with the complexities pertaining to revenue recognition under long term construction accounting. Additionally, he has performed cost certifications verifying the construction costs for HUD related projects and has testified in numerous types of litigation matters, including construction litigation.

Scott has led project cost reviews requiring the verification of project costs. These types of reviews entailed many procedures including contract reviews, interviewing various construction team personnel, scrutinizing payment applications, review of budgets and schedules, review of change orders, and scrutinizing the job cost records. Other procedures entailed tracing recorded costs from job cost records to various source documentation, reviewing field logs, reviewing change order logs, recalculating labor burden rates, recalculating self-owned equipment charge rates, testing for ghost employees and reviewing other areas identified to be at risk for the owner.

In addition to performing cost reviews, Scott also has performed forensic accounting assignments for contractors. In one particular engagement, Scott led an investigation pertaining to allegations of cost shifting between individual job codes by a project manager for a multi-million dollar HVAC contractor. Procedures included review of processes and controls over cost recording, testing of revenue recognition under percentage of completion, interviews of key personnel, email review and testing of payment applications and change orders and tracing certain individual cost items to underlying documentation and approvals.

Scott is a Certified Construction Auditor (CCA), Certified Public Accountant (CPA), Certified Fraud Examiner (CFE), and earned his M.B.A.

Presentations and Publications

Scott has presented on numerous occasions on topics pertaining to business valuation, financial discovery, accounting, economic damages, internal investigations and fraud.

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David Malamed

CPA, CA, DIFA, CPA (IL), CFF, CFE, CFI

Partner, Advisory Services

Forensic Accounting and Investigative Services

Experience

David Malamed is recognized as a leading court qualified Canadian expert with detail-oriented forensic accounting knowledge and experience. David is committed to providing value-add for his clients. His point blank perspective, ability to simplify complex issues and strategic insight has assisted Grant Thornton clients in recovering millions of dollars, meeting regulatory requirements and minimizing exposure and risk.

As one of the elite few forensic accounting partners in Canada, David has provided over fifteen years of quality service and excellent results. David has qualified as an expert and testified numerous times in both Ontario and Superior Court.

David has experience in fraud prevention and detection programs, forensic accounting investigation, and litigation support and dispute resolution. Specialties areas of focus include:

- Construction disputes;
- Contract Disputes (i.e. Pre and Post Purchase and Sale Contracts);
- Insurance Claims Auditing and Investigation;
- Workplace fraud investigation and dispute resolution services; and
- Expert Witness testimony.

David is a Forensic Accounting Partner with Grant Thornton's Forensic and Dispute Resolution practice. David is a Chartered Professional Accountant, a Chartered Accountant specializing in Investigative Forensic Accounting, a Certified Public Accountant, a Certified Fraud Examiner, a Certified Fraud Investigator and Certified in Financial Forensics.

David conducts and manages investigations on behalf of corporations, law firms, individuals, governments, law enforcement agencies, and other Public sector organizations. Some of David's recent client engagements have included:

- Investigated multiple construction disputes;
- Investigated underpayments relating to common costs for 500+ lease agreements;
- Investigated numerous financial disbursement irregularities including cheque fraud, invoice splitting, and bid rigging;
- Ongoing assistance to law enforcement agencies including the Toronto Police and Peel Police fraud squads for use in court and expert witness reports;
- Litigation support for a mortgage fraud investigation;
- Investigating executive employee expense fraud;
- Damage quantification due to breaches of non-solicit agreements;
- Investigating allegations of employee expense report and time records fraud;

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- Investigating allegations of false invoices and misappropriated funds by an employee;
- Investigating suspicious transactions relating to senior management bonus structure;
- Performing an internal investigation of transactions relating to the restatement of a public communication company; and
- Investigating and damage quantification of an insurance denial.

Professional qualifications

- Certified in Financial Forensics (CFF)
- Certified Forensic Investigator (CFI)
- Canadian Institution of Chartered Accountants, specialist in Investigative Forensic Accounting (CA.IFA)
- Certified Public Accountant (CPA)
- Certified Fraud Examiner (CFE)
- Chartered Accountant (CA)
- Bachelor of General Studies, University of Athabasca

Memberships

- Institute of Chartered Accountants of Ontario
- Canadian Institute of Chartered Accountants
- Alliance for Excellence in Investigative and Forensic Accounting
- Association of Certified Fraud Examiners
- Illinois Certified Public Accounting Society
- Association of Certified Fraud Investigators

Presentations and Publications

David is frequently invited to speak on forensic accounting and fraud investigation, and writes on these topics. He is the Chartered Professional Accountant Magazine's Technical Editor for Fraud and a regular columnist. In 2012 and 2013 David's column was awarded the Kenneth R. Wilson award.

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Appendix B – Documents relied upon

Throughout this engagement we have had access to a large volume of documents. The following represents the documents that have been referenced throughout the body of this report. :

NAL Ref# / Author	Title of Reference	Date
NAL0020789	Monthly Construction Report MFG & LTA	December 31, 2017
NAL0020767	Monthly Construction Report LIL	December 31, 2017
Nalcor Energy	Understanding Muskrat Falls – Stan Marshall, CEO Nalcor Energy	February 15, 2018
NAL0018800	Independent Supply Decision Review	September 14, 2011
NAL0019060	Reference to the Board – Review of Two Generation Expansion Options For The Least-Cost Supply of Power To Island Interconnected Customers For The Period 2011 – 2067	March 30, 2012
NAl0019056	Nalcor's Submission to the Board of Commissioners of Public Utilities with respect to the Reference from the Lieutenant-Governor in Council on the Muskrat Falls Project	November 10, 2011
NAL0018916	Report on Two Generation Expansion Alternatives for the Island Interconnected Electrical System, Volume 1: Summary of Reviews	January 2012
NAL0018917	Report on Two Generation Expansion Alternatives for the Island Interconnected Electrical System, Volume 2: Studies	January 2012
NAL0018691	Review of Muskrat Falls and Labrador Island HVdc Link and the Isolated Island Options	October 2012
NAL0000195	Decision Gate 2 Support Package	November 16, 2010
NAL0063739	Gateway Process	March 24, 2009
NAL0019519	Pacesetter Evaluation of the Muskrat Falls Generation Project and Island Link Transmission Project	September 2010
NAL0017689	Project Governance Plan	January 6, 2009
NAL0018156	Gateway Process	June 9, 2011
NAL0391751	Independent Project Review Report	August 31, 2012
NAL0391745	Independent Project Review Report (Updated)	August 31, 2012

NAL Ref# / Author	Title of Reference	Date
Nalcor Energy	Response to Grant Thornton Question 8.4	July 6, 2018
Nalcor Energy	Response to Grant Thornton Question 8.6	June 17, 2018
	Electrical Power Control Act	1994
NAL0018682	Government of Newfoundland and Labrador – Energy Plan	2007
Pan Maritime Kenny	Technical Feasibility of Offshore Natural Gas and Gas Liquid Development Based on a Submarine Pipeline Transportation System	October 2001
Dr. Stephen E. Bruneau	Submission to PUB “discussion points – natural gas for island electrical generation”	February 13, 2012
Dr. Stephen E. Bruneau	Grand Banks Natural Gas for Island Electric Generation	March 28, 2012
NAL0018671	Natural Gas as an Island Power Generation Option	October 30, 2012
NAL0018708	Review of “Grand Banks Natural Gas As An Island Electric Generation Option”	November 2012
NAL0018880	An Assessment of Limitations for Non-dispatchable Generation on the Newfoundland Island System	October 2004
NAL0018669	Report for Wind Integration Study – Isolated Island	August 7, 2012
NAL0018692	Review of the Wind Study for the Isolated Island of Newfoundland	October 2012
NAL0019237	Board Package to 33rd Board Meeting, Island Energy Supply and Lower Churchill – Option Evaluation and Recommendation	November 16, 2010
Nalcor Energy	Response to Grant Thornton Question 8.10 – OutputComparison.PLF10Init.Base.Oct27v2.xls	July 10, 2018
Nalcor Energy	Response to Grant Thornton Question 8.10	July 10, 2018
Nalcor Energy	Response to Grant Thornton Question 8.11	July 10, 2018
Muskrat Falls Project	Summary of Pre-Sanction – Briefing Note as Requested by Nalcor Legal Counsel McInnes-Cooper	
NAL0018695	Gull Island: Why Not Develop Gull Island First	November 2012
The Department of Natural Resources	Electricity Imports	July 2012
Nalcor Energy	Response to CA/KPR-Nalcor-32	Muskrat Falls Review
NAL0018957	Nalcor's Final Submission to the Board of Commissioners of Public utilities with respect to the reference from the Lieutenant-Governor In Council on the Muskrat Falls Project	March 2, 2012
Nalcor Energy	Response to Grant Thornton Question 5.3	June 8, 2018

NAL Ref# / Author	Title of Reference	Date
Newfoundland and Labrador Hydro	2014 Investigation and Hearing into Supply Issues and Power Outages on the Island Interconnected System, PUB-NLH-058	2014
Nalcor Energy	Response to Grant Thornton Question 5.2 – GT RFI Q5.2_2014 Newfoundland and Labrador Hydro Planning Process Review – VENTYX FINAL March 21.docx	March 21, 2014
Nalcor Energy	Grant Thornton RFI 5.2 – Power Advisory – Review of NL Electricity System - 2015	October 26, 2015
Nalcor Energy	Response to Grant Thornton Question 5.2	June 8, 2018
Deloitte LLP	British Columbia Hydro and Power Authority – British Columbia Utilities Commission Inquiry respecting Site C – Project No. 1598922	September 8, 2017
The Public Utilities Board	Report on the Needs For an Alternative To (NFAT), Review of Manitoba Hydro's Preferred Development Plan	June 2014
Nalcor Energy	Response to Grant Thornton Question 2.6	May 29, 2018
Ausgrid	Appendix 5 Price Elasticity of Demand	November 2015
RAND Corporation - Bernstein and Griffin	Regional Differences in the Price-Elasticity of Demand for Energy	2005
Marbek Resource Consultants Ltd.	Conservation and Demand Management (CDM) Potential Newfoundland and Labrador, Residential, Commercial and Industrial Sectors	January 31, 2008
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Appendix C – Glossary of abbreviated terms

Abbreviations	Full Term
AACE	Association for Advancement of Cost Engineering
BCUC	British Columbia Utilities Commission
CBOC	Conference Board of Canada
CBPP	Corner Brook Pulp & Paper
CCE	Capital Cost Estimate
CCS	Carbon Capture and Storage Technology
CCCT	Combined Cycle Combustion Turbine
CDM	Conservation and Demand Management
CFLCo	Churchill Falls (Labrador) Corporation
Commission	The Commission of Inquiry Respecting the Muskrat Falls Project
COS	Cost of Service
CPW	Cumulative Present Worth
CT	Simple Cycle Combustion Turbine
DG2	Decision Gate 2
DG3	Decision Gate 3
DNR	Department of Natural Resources
Emera	Emera Inc.
Energy Plan	The Government of Newfoundland and Labrador Energy Plan
EPCM	Engineering, Procurement, Construction Management
ESPs	Electrostatic Precipitators
FGD	Flue Gas Desulphurization
GDP	Gross Domestic Product
GHG	Greenhouse Gas
Government/GNL	Government of Newfoundland and Labrador
HQ	Hydro Quebec
HVac	High Voltage Alternating Current

Abbreviations	Full Term
HVdc	High Voltage Direct Current
Interconnected Island Option	Muskrat Falls
IPA	Independent Project Analysis Inc.
IPR	Independent Project Review
IRR	Internal Rate of Return
LCP	Lower Churchill Project
Liberty	The Liberty Consulting Group
LIL	Labrador Island Transmission Link
LNG	Liquefied Natural Gas
LOLH	Loss of Load Hours
LTA	Labrador Transmission Assets
MF	Muskrat Falls
MFG	Muskrat Falls Generating
MHI	Manitoba Hydro International
MHI January 2012 Report	Manitoba Hydro Report – Report on Two Generation Expansion Alternatives for the Island Interconnected Electrical System Volume 1 & 2
MHI October 2012 Report	Manitoba Hydro Report - Review of the Muskrat Falls and Labrador Island HVdc Link and the Isolated Island Options
ML	Maritime Link
Muskrat Falls / Project	Muskrat Falls Project
MW	Megawatt
Nalcor	Nalcor Energy
Navigant	Navigant Consulting Ltd.
Navigant Report	Independent Supply Decision Review
NE-LCP	Nalcor Energy – Lower Churchill Project
NEB	National Energy Board
NEB Report	Nation Energy Board Report titled, “Canada’s Energy Futures: Energy Supply and Demand Projections to 2035”
NEISO	New England Independent System Operator
NERC	North American Electric Reliability Corporation
NG	Natural Gas
NLH	Newfoundland and Labrador Hydro
NP	Newfoundland Power

Abbreviations	Full Term
NSPML	NSP Maritime Link Incorporated
NSUARB	Nova Scotia Utility and Review Board
PDI	Personal Disposable Income
Period of Review	November 16th, 2010 – December 17, 2012
PIRA	PIRA Energy Group
PLF	Planning Load Forecast
PPA	Power Purchase Agreement
Project	Lower Churchill Project
Project Team	Nalcor Lower Churchill Project Team
P.U.B.	Newfoundland and Labrador Board of Commissioners of Public Utilities
P.U.B. Report to Government	Review of Two Generation Expansion Options for the Least-Cost Supply of Power to Island Interconnected Customers for the Period 2011-2067
PV	Photovoltaic
QRA	Quantitative Risk Assessment
Regas	Regasification
RORB	Return on Rate Base
SNC	SNC Lavalin
WACC	Weight Average Cost of Capital
Westney	Westney Consulting
Ziff	Ziff Energy Group

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