

Report on Two Generation Expansion Alternatives for the Island Interconnected Electrical System

Volume 1: Summary of Reviews

January 2012

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Prepared for:
Board of Commissioners of Public Utilities
Newfoundland and Labrador

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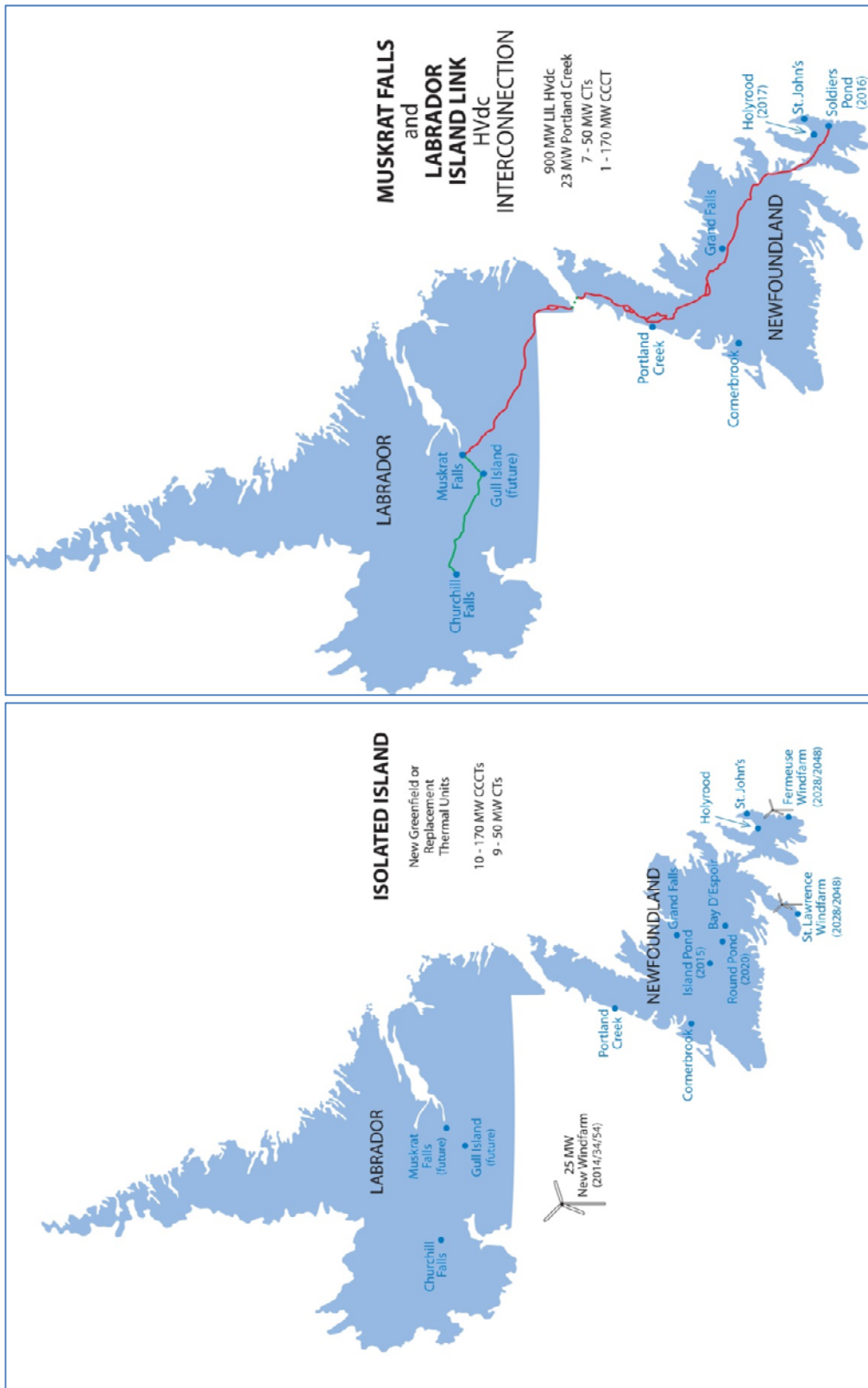
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Executive Summary

Background

In June 2011 the Lieutenant-Governor in Council of Newfoundland and Labrador referred to the Board of Commissioners of Public Utilities (the Board) a Reference Question requesting the Board review and report to Government on whether Nalcor Energy's (Nalcor) proposed Muskrat Falls Generating Station and Labrador-Island Link HVdc projects are the least cost option for the supply of power and energy to the Island of Newfoundland as compared to the Isolated Island Option.

The Reference Question stated:

"The Board shall review and report to Government on whether the Projects represent the least-cost option for the supply of power to Island Interconnected Customers over the period of 2011-2067, as compared to the Isolated Island Option, this being the 'Reference Question'.

In answering the Reference Question, the Board:

- shall consider and evaluate factors it considers relevant including NLH's and Nalcor's forecasts and assumptions for the Island load, system planning assumptions, and the processes for developing and comparing the estimated costs for the supply of power to Island Interconnected Customers; and*
- shall assume that any power from the Projects which is in excess of the needs of the Province is not monetized or utilized, and therefore the Board shall not include consideration of the options and decisions respecting the monetization of the excess power from the Muskrat Falls generation facility, including the Maritime Link Project."*

The Reference Question identifies the two options to be compared:

1. the Infeed Option which is the Muskrat Falls Generating Station and Labrador-Island Link HVdc project; and
2. the Isolated Island Option.

It should be noted that the investigation of alternative fuel types, other island supply options, consideration of the export market via the Maritime Link, the technical feasibility of the Maritime Link, electricity requirements in Labrador as well as potential impacts on island rates were not included in the review by the Terms of Reference.

Generation Expansion Options

Nalcor's planning load forecast for 2010 projected energy requirements for that year at 7,585 GWh increasing to approximately 12,000 GWh by 2067. Year 2067 was chosen as the end of forecast period as this matches the estimated life of the Labrador-Island Link electrical infrastructure and is a suitable timeframe to depreciate that asset. This forecast, as well as Nalcor's generation planning criteria, indicates island capacity deficits (inability to meet peak demand) starting in 2015 with energy deficits (inability to meet annual load requirements) occurring post-2019. Nalcor's generation expansion

analysis led to the identification of the two alternatives under review to address these capacity and energy deficits.

The Infeed Option is largely a hydroelectric generation plan (900 MW from the Muskrat Falls Generating Station and Labrador-Island Link HVdc system, and 23 MW from Portland Creek Generating Station), with the addition of 520 MW of thermal generation using combustion turbines. Power from Muskrat Falls Generating Station on the Lower Churchill River in Labrador is planned to be supplied to Newfoundland over the Labrador-Island Link HVdc transmission line that would cross the Strait of Belle Isle. The annual average energy from Muskrat Falls Generating Station is estimated at 4,900 GWh with first power available in 2016. When all Muskrat Falls Generating Station power is required to satisfy load requirements on the island, or reliability criteria are about to be violated, additional hydro and thermal resources are required to ensure an adequate supply of capacity and energy to meet demand. The cumulative present worth of the Infeed Option in 2010 was estimated by Nalcor at \$6,651 million.

The Isolated Island Option is largely a thermal generation plan (1,640 MW), with the addition of 77 MW of small hydroelectric generating stations and 79 MW of wind power. The net 465.5 MW Holyrood Thermal Generating Station, which consumes up to 18,000 barrels of oil a day, plays a major role in this option. The generation plan includes:

- Installation of environmental emissions controls at Holyrood (electrostatic precipitators, scrubbers and NOx burners) as per Newfoundland and Labrador Government's policy directives
- Life extension projects at Holyrood with eventual replacement of the units in 2033 and 2036
- 25 MW wind farm
- 2 X 27 MW wind farm replacements
- 36 MW Island Pond Generating Station
- 23 MW Portland Creek Generating Station
- 18 MW Round Pond Generating Station
- 1,640 MW of 50 MW Combustion Turbines and 170 MW Combined Cycle Combustion Turbines. This includes 510 MW for replacement of the Holyrood units.

The cumulative present worth of the Isolated Island Option in 2010 was estimated by Nalcor at \$8,810 million.

Scope of Work and Report Structure

Manitoba Hydro International (MHI) was engaged as the Board's independent expert consultant to assist the Board in their review.

MHI has reviewed the technical feasibility and cumulative present worth analysis for the two power supply options identified in the Reference Question to serve the Island of Newfoundland with electricity until 2067.

Nalcor is using a staged or phased decision gate process to determine if, and how, the Infeed Option should proceed¹. Phase 1 of the Infeed Option passed through a decision point, described by Nalcor as Decision Gate 2 (DG2), in November, 2010. DG2 is considered to be approval of a development scenario and allows for commencement of detailed design. Following DG2, engineering will progress to a level required to support project sanction or approval, which is Decision Gate 3 (DG3).

Capital cost estimates evolve with improving accuracy as the level of engineering progresses. Nalcor has adopted estimating practices of the Association for the Advancement of Cost Engineering (AACE) International for the Infeed Option. Nalcor considers the DG2 capital cost estimate to be commensurate with an AACE Class 4 estimate which is a feasibility estimate and has a range of accuracy of +50% to -30%.² The DG3 or project sanction capital cost estimate is considered by Nalcor to be a Class 3 estimate with a range of accuracy of +30% to -20%.³

MHI reviewed Nalcor's documentation submitted to the Board, prepared Requests for Information (RFI) and reviewed responses from Nalcor, and met with Nalcor staff and their consultants. MHI's report is based on this information and responses to RFIs received up to January 16, 2012. The information provided by Nalcor and reviewed by MHI was generally current as of the fall of 2010 and was used by Nalcor in making its DG2 decision. Nalcor did not generally provide information on the detailed engineering or financial work completed after DG2. Thus the findings in this Report relate to project components and costs as of DG2.

The investigation was approached from two perspectives: a technical review of available studies and related information from Nalcor to determine if the degree of skill, care, and diligence required to meet utility best practices and procedures were followed for the work done to date, and a financial review of the cumulative present worth analysis used to select the least cost alternative. MHI has documented the results of these reviews in the two volumes of this report.

To perform the review MHI assembled a team of specialists with expertise in load forecasting, risk analysis, project management, utility resource planning, hydroelectric and thermal generation, HVdc engineering, hydrology, submarine cable crossings, wind power, and financial analysis.

MHI's report is comprised of two Volumes. Volume 1 contains the Executive Summary, key findings, review methodology and high level summaries of the various technical and financial reviews. Volume 2 contains the detailed reports of the reviews and an overview of the MHI team.

¹ "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 2, p. 32

² "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 2, p. 72

³ CE-51 Rev. 1 (Public), Nalcor, "Technical Note: Muskrat Falls Generation Facility and Labrador – Island Transmission Link Overview of Decision Gate 2 Capital Cost and Schedule Estimates", August 2011, p. 11

Key Findings

MHI found that Nalcor's work and that of the consultants they engaged is well-founded and generally in accordance with industry practices as of DG2 with certain significant exceptions noted in these key findings. The key findings of MHI's review are summarized below.

Load Forecast Findings

1. **Forecast Preparation** – A detailed analysis of Nalcor's load forecasting practices and methodologies confirms that the load forecast has been performed with due diligence and care using generally accepted practices, except as noted in key finding #2.
2. **Load Forecast Accuracy** – The domestic forecast methodology is acceptable, but consistently under-predicts future energy needs at a rate of 1% per future year. The domestic forecast is entirely prepared using econometric modeling techniques. Although these techniques are acceptable, they are not the best utility forecast practices for this sector. Best utility practices would incorporate end-use modeling techniques into the forecasting process so that electricity growth can be quantified for all major domestic end-uses.

The general service forecast methodology used by Nalcor is based on a combination of regression modeling and linear extrapolation techniques that have performed extremely well in the past. The general service forecast has produced accuracy levels within 1-2%, as far as 8-9 years into the future.

The industrial forecast is prepared on an individual, case-by-case basis, with direct customer contact concerning future operational plans. This methodology is reasonable considering the small industrial customer base on the island, but, in hindsight, the assumption of continued operation of two pulp and paper mills was too optimistic and has adversely affected the industrial forecast accuracy. The assumption of continued operation of the one remaining pulp and paper mill throughout the forecast horizon is optimistic and the assumption of no new industrial load additions after 2015 is pessimistic. The amount of variability due to potential load changes is high and could materially impact the results of the cumulative present worth analysis.

Generation Resource Planning Process Findings

3. **Options for Review** – Nalcor has an exhaustive process for reviewing generation options that is in keeping with leading North American utilities. The *Strategist* software used by Nalcor to evaluate and select a preferred generation development scheme is appropriate. It should be noted that the addition of a large industrial load on the island or in Labrador could result in a different generation expansion plan.

Hydrology Findings

4. **Hydrology Studies** – The Muskrat Falls studies were conducted in accordance with utility best practices, comprehensively, and with no apparent demonstrated weaknesses. Also, the energy and capacity estimates for Muskrat Falls and the three small hydroelectric facilities on the island, which were prepared by various consultants using industry accepted practices, were reviewed and confirmed to be reasonable for DG2.

Power System Reliability Findings

5. **Forced Outage Rates** – The forced outage rates (FOR) assumed for various types of generating units are based on reliable sources and considered to be reasonable. The information documenting the derivation of the Labrador-Island Link HVdc system FOR of 0.89% on a per pole basis was not available for MHI's review. MHI has compared the Labrador-Island Link HVdc system pole FOR of 0.89% with published information and that of Manitoba Hydro's HVdc system and finds it within the normally accepted range. However, this FOR should be replaced by a more advanced and comprehensive reliability model incorporating all components of the Labrador-Island Link HVdc system.
6. **System Reliability Studies** – Probabilistic adequacy studies, including considerations related to transmission for comparison of the reliability of the two options, have not been completed by Nalcor. This is a gap in Nalcor's practices as various Canadian utilities including Manitoba Hydro, BC Hydro, Hydro Quebec, and Hydro One in Ontario have adopted these probabilistic methods for reliability studies for major projects. Probabilistic reliability methods utilize standard terms and indices such as Loss of Load Expectation, or Expected Unserved Energy, and make the risk analysis results plainly understandable in terms of dollars and/or loss of load.

Deterministic assessments, such as those performed by Nalcor in Exhibit 106, cannot quantify the true risks associated with a power system and are unable to provide some of the important inputs for making sound engineering decisions such as risk and associated costs, including the potential large societal costs related to outages. Probabilistic assessment is a valuable means to assess system risk, reliability and associated costs/benefits for various system improvement options, particularly for major projects proposed by Nalcor. MHI has determined that choosing between the two options under review without such an assessment is a gap in Nalcor's work to date. Typically, these studies are completed at DG2. MHI recommends that these probabilistic reliability assessment studies be completed as soon as possible. Such studies should become part of Nalcor's processes that would allow for a comparison of the relative reliability for future facilities.

AC Integration Study Findings

7. **AC Integration Studies** – System integration studies completed as part of the project alternatives screening process, and provided to MHI by Nalcor were for a Gull Island development with a 1600 MW three terminal HVdc system to Newfoundland and New Brunswick. Significant changes were made to the overall project definition with the proposed Muskrat Falls development, and the deletion of the New Brunswick link. Integration studies that would support the changes have not been completed and Nalcor now advises that the studies will not be available until March 2012⁴. As the full requirements for integration of the Labrador-Island Link HVdc system are not known, there may be additional risk factors that may impact the cumulative present worth of the Infeed Option. For example, installation of backup supplies to cover operational limitations in the Labrador-Island Link HVdc system may be required, and additional transmission lines may be needed to maintain acceptable system performance. Spare equipment requirements also need to be taken into consideration. Good utility practice requires that these integration studies be completed as part of the project screening process (DG2). MHI considers this a major gap in Nalcor's work to date. These integrations studies must be completed prior to project sanction (DG3).
8. **NERC Standards** – Nalcor currently does not comply with North American Electric Reliability Corporation (NERC) standards^{5,6}. A majority of utilities in Canada have adopted the definition of "good utility practice" that incorporates adherence to NERC standards. Also, should the Maritime Link proceed, and Nalcor participates in the electricity marketplace, NERC standards will ultimately apply. MHI recommends that Nalcor complete a self-assessment and prepare for compliance to NERC standards with or without the Maritime Link.

Muskrat Falls Generating Station Findings

9. **Muskrat Falls Technical and Construction Feasibility** - MHI's review of the Muskrat Falls Generating Station concluded the following:
 - The proposed layout and design of Muskrat Falls Generating Station appears to be well defined and consistent with good utility practices.
 - The general arrangement of the permanent works is a reasonable proposal for the optimum development in terms of cost and construction duration.
 - Based on the information provided, the design and construction of Muskrat Falls Generating Station is consistent with good engineering and construction practices, and should not pose any unusual risks for construction or operation of the facilities.
 - The available studies have identified technical risks and appropriate risk mitigation strategies.

⁴ Response to RFI PUB-Nalcor-143

⁵ Exhibit 106, Nalcor, "Technical Note Labrador –Island HVdc Link and Island Interconnected System Reliability", pg. 33

⁶ Response to RFI PUB-Nalcor-164

10. **Muskrat Falls Cost Estimate Increase** – The cost estimate for the Muskrat Falls development has increased by 104% between 1998 and 2010 which can largely be explained by inflation and a change in scope. The change in scope is the addition of the 2 – 345 kV transmission lines from Muskrat Falls Generating Station to Churchill Falls Generating Station, associated switchyards, environmental costs and other items such as insurance. Despite the additional costs, MHI considers the cost estimate at DG2 to be within the accuracy range of an AACE Class 4 estimate (+50%/-30%) which is representative of a feasibility level study.

HVdc Converter Stations Findings

11. **Application of HVdc to the Island Power System** – MHI found that the HVdc converter station system design parameters available for review are reasonable for the intended application. The intended application is to transmit 900 MW of firm power over 1100 km of transmission line and inject this power into the island's electrical system at Soldiers Pond with appropriate voltage and frequency control.
12. **Capital Cost Estimate of the Labrador-Island Link HVdc Converter Station** – The estimate for the HVdc converter stations and electrodes was reviewed by MHI and found to be within the range of an AACE Class 4 estimate. The cost estimates for the synchronous condensers are low but are still within the range of an AACE Class 4 estimate.
13. **Choice of HVdc Technology** – The Labrador-Island Link design progression has specified LCC (line commutated converters) HVdc technology, which is mature and robust for the application⁷. However, the response to RFI MHI-Nalcor-67 has indicated that VSC (voltage sourced converter) options will be considered if there are technical and financial advantages to do so. It is important to note that VSC systems of the size and length of the Labrador-Island Link HVdc system have not yet been built and operated anywhere in the world as of the issue date of this report.

HVdc Transmission Line Findings

14. **Design Loading Criteria** – Nalcor has selected a 1:50-year reliability return period (basis for design loading criteria) for the HVdc transmission line, which is inconsistent with the recommended 1:500-year reliability return period outlined in the International Standard CEI/IEC 60826:2003 with Canadian deviations in CSA Standard CAN/CSA-C22.3 No. 60826:06, for this class of transmission line without an alternate supply. In the case where an alternate supply is available, the 1:150-year reliability return period is acceptable. In this latter scenario, Nalcor should also give consideration to an even higher reliability return period in the remote alpine regions⁸. MHI considers this a major issue and strongly recommends that Nalcor adhere

⁷ Exhibit 30, Nalcor, "Lower Churchill Project Design Progression", July 2011.

⁸ Exhibit 97, Page 8. Alpine regions are defined as Southeastern portion of Labrador, two areas in the Long Range Mountains, and one small section in central Newfoundland.

to these criteria for the HVdc transmission line design. The additional cost to build the line to a 1:150 year return period is approximately \$150 million⁹.

15. ***HVdc Overhead Transmission Line Capital Cost Estimate*** – The capital cost estimate of the transmission line at DG2 is reasonable, but at the low end of the range for this type of construction utilizing industry benchmark costs as a comparison. A design based on a 150-year return period could be accommodated within the variability of an AACE Class 4 estimate at this stage of development for the entire Labrador-Island Link HVdc project.

Strait of Belle Isle Marine Crossing Findings

16. ***Cable Technology*** – Mass impregnated cable, as specified by Nalcor, is an appropriate technology for an HVdc marine crossing at ± 350 kV. Other technologies, such as cross-linked polyethylene cable (XLPE), have been type tested for this application at ± 320 kV, but none have been used at this voltage on a marine HVdc project in the world to date.
17. ***Marine Crossing Cost Estimate*** – Nalcor's total base cost estimate for the marine crossing at DG2 was reviewed by an independent consultant, CESI, retained by MHI and familiar with cable crossings. It was found that this estimate is within the range of an AACE Class 4 cost estimate.
18. ***Marine Crossing Iceberg Risks*** – The iceberg risks are perceived to be significant; however, the application of horizontal directional drilling for shore landings, years of iceberg observations and research performed by C-CORE (a local consulting firm) on the Grand Banks for the various oil projects, and careful route selection across the Strait of Belle Isle have quantified the risks to be less than one iceberg strike in 1000 years. This risk is further mitigated with rock berms, largely for fishing equipment and anchor protection, and a spare cable with separation distance between them of 50 to 150 metres. The research performed by C-CORE found that the risk of a multiple cable contact by icebergs was reduced with greater separation of the cables. Additional research, monitoring of iceberg roll rates, and bathymetric surveys of earlier iceberg scours should be done to provide a level of validation to further tune the iceberg strike risk model.
19. ***Spare Cable*** – The application of a spare cable is a prudent design feature of the Strait of Belle Isle marine crossing considering the difficulties of bringing in repair equipment at certain times of the year.

⁹ Response to RFI PUB-Nalcor-15

Small Hydroelectric Plant Findings

20. **Small Hydroelectric Plants** – For the three small hydroelectric plants of the Isolated Island Option, a review of the capital cost estimates indicated that the level of engineering and investigations was consistent with a feasibility level study. Considering the age of some of the studies, the review also indicated that the development schedules and cost estimates for the three projects are optimistic due to more stringent current regulatory processes.

It is expected that resolution of these uncertainties would generally result in increases rather than decreases in the cumulative present worth of the three small plants. However, the magnitude of any changes would not significantly alter the difference in the cumulative present worth between the Isolated Island and Infeed Options.

Thermal Generating Station Findings

21. **Thermal Options Studies** – The thermal studies related solely to the Isolated Island Option were screening level studies, while there was a great deal more depth to studies of the Infeed Option. The level of detail of studies on upgrading the Holyrood Thermal Generating Station was found to be adequate, and the related upgrade costs are reasonable and in line with industry standards.
22. **Holyrood Life Extension Cost Estimates** – Although the Holyrood Thermal Generating Station life extension costs for the Isolated Island Option are not based on detailed engineering studies, the estimates in the cumulative present worth analysis are conservative and representative of similar plants. This expenditure is needed to extend the life of the plant as a generating facility to 2033 for units 1 and 2, and 2036 for unit 3.
23. **Holyrood Service Life** – Even with life extension under the Isolated Island Option, operating Holyrood Thermal Generating Station beyond 50 years, to a maximum of 60 years, with reduced reliability, may not be practical. There may come a point well before 2041 when the plant becomes unreliable to operate.¹⁰ The life extension plan and requirements under the Infeed Option are as follows:
- 2010 to 2017 Electricity Generation
 - 2017 to 2021 Electricity Generation, as-required primarily on a standby basis
 - 2017 to 2041 Synchronous Condenser Operation – Units 1 and 2 converted to synchronous condenser mode by 2017. Unit 3 is already synchronous condenser capable.

¹⁰ Exhibit 44, AMEC, “Holyrood Thermal Generating Station Condition Assessment & Life Extension Study”, January 2011.

24. **CT and CCCT Technology** – The technology and base costs assumed for the 50 MW combustion turbine (CT) and the 170 MW combined cycle combustion turbine (CCCT) installations are reasonable. The technology and costs assumed for replacing Holyrood Thermal Generating Station using CCCTs under the Isolated Island Option are reasonable based on present utility plant retirements for plants built in the late 1960's and early 1970's.
25. **Holyrood Decommissioning Costs** – A detailed site assessment study for decommissioning the Holyrood Thermal Generating Station has not yet been completed by Nalcor. The costs of decommissioning the station are high level estimates, but they are considered reasonable when compared to similar recent projects.

Wind Farms Findings

26. The capacity factor of 40% used by Nalcor is reasonable for a planning study. The estimated capital and operating costs used in the analysis are appropriate. Nalcor's assessment of an 80 MW limit for wind generation under the Isolated Island Option is reasonable. Additional wind power could be installed beginning in the 2025 timeframe as the system capacity grows.

Cumulative Present Worth Analysis Findings

27. The Option with the Lowest Cumulative Present Worth – Based on the capital and operating costs estimated by Nalcor for each option and a common load forecast, Nalcor has determined that the Infeed Option has a lower cumulative present worth than the Isolated Island Option by approximately \$2.2 billion. The detailed analysis performed by MHI determined that Nalcor's cumulative present worth analysis was completed using recognized best practices and the cumulative present worth for each option was correct based on the inputs used by Nalcor. These inputs were reviewed in the technical and financial analyses conducted by MHI and were generally found to be appropriate. There are, however, other considerations related to risks associated with the assumptions used for certain key inputs such as load, fuel prices and cost estimates which may impact the cumulative present worth analysis for the two options. These were tested with the use of several sensitivity analyses and the results of these are summarized as follows:

- **Load Forecast**
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 of the Muskrat Falls Generating Station and Labrador-Island Link HVdc projects increase by 10%, the cumulative present worth for the two Options would be approximately equal¹¹.
- **Capital Cost Estimates**
The current capital estimates are within the accuracy of an AACE Class 4 estimate which has a plus factor variance potential of as much as 50%. Should cost overruns reach that level, the difference between cumulative present worth values for each of the two Options would be less than \$200 million in favour of the Infeed Option.
- **Fuel Price**
There remains significant uncertainty in fuel price forecasts. Global disruptions in supply could drive the price of oil well above inflation. However, new sources of supply, such as shale oil or downward trends in natural gas pricing, may have the potential to minimize fuel price increases.

If fuel prices drop by 44% from those used by Nalcor, there is no difference between the two cumulative present worth results for the two Options. However, if fuel prices rise more than the reference price used in the cumulative present worth analysis, an even greater difference between the cumulative present worth results would occur.

The risks associated with these inputs are further magnified considering the 50+ year period (2010 – 2067) used in the preparation of the cumulative present worth analysis.

¹¹ MHI derived from RFI MHI-Nalcor-41 Revision 1

General Findings

28. **Renewable Sources of Energy** – The Infeed Option uses more renewable energy sources than the Isolated Island Option. The amount of thermal generation capacity required in 2067 is 35% for the Infeed Option, almost the same proportion that exists in 2010. In contrast, the amount of thermal generation for the Isolated Island Option is projected to reach 62% in 2067, nearly double that of the island mix in 2010 necessitated by greater reliance on thermal energy sources.^{12,13}

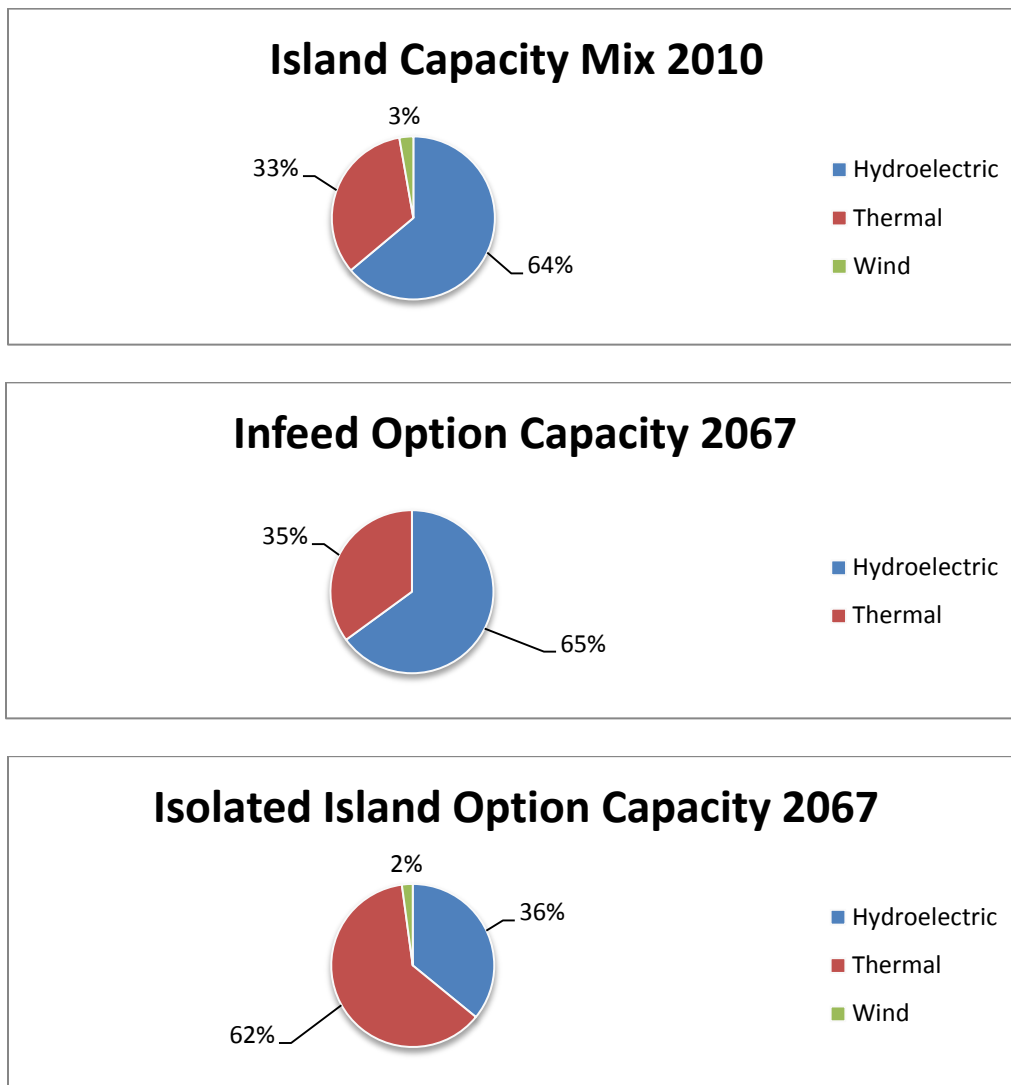


Figure 1: Option Capacity Mix. Use of renewable energy sources between the two options

¹² Exhibit 14 Rev. 1, Nalcor, "2010 PLF Strategist Generation Expansion Plans"

¹³ Exhibit 16, Nalcor, "Generation Planning Issues", July 2010

29. **Carbon Credits** – Nalcor’s Final Submission notes that carbon credits have not been factored into the cost analysis of either option as future carbon emission trading, and its pricing, contains uncertainties regarding timing, scope and design associated with the future regulatory framework. It is possible that future Holyrood Thermal Generating Station operation and redevelopment, and the addition of combustion turbine power plants, may be subject to additional operating costs due to the requirement to purchase carbon credits to offset the greenhouse gases (GHG) these plants emit.
30. **Environmental Concerns** – The matter of environmental stewardship is a concern associated with the Isolated Island Option. The Holyrood generating facility has a combined capacity of 465.5 MW and, at peak production, burns approximately 18,000 barrels of oil per day. Even though Nalcor has projected a capital cost of \$603 million for an environmental equipment upgrade, this investment will not reduce GHG emissions, which are expected to increase as the load factor of the plant increases. Should the GHG emission standard change through public policy to a lower target, there is the risk that an oil fired facility such as Holyrood may not be able to operate in the long term.

Conclusions and Recommendations

MHI completed a detailed review of the information generally as of DG2 provided by Nalcor on the Infeed and Isolated Island options and has made a number of key findings. While the work and analysis completed by Nalcor generally meets utility best practices, there are several significant exceptions which have been noted above and are summarized as follows:

- **Reliability Assessment**

Recent reliability studies completed for, or by, Nalcor are deterministic in nature. The probability assessments done with Strategist are solely resource adequacy studies without consideration for transmission.

Power system behaviour is, however, stochastic in nature and the uncertainties in power systems have been augmented by various factors such as advancements in technology, the increased complexity of system design and operation, the deregulation of the utility business, the increased utilization of intermittent energy sources and the imposition of more mandatory regulatory requirements.

Therefore, the assessment of such systems exposed to uncertainties should use probabilistic or risk-based techniques. Deterministic assessment cannot quantify the true risks associated with a power system and is unable to provide some of the important inputs for making sound engineering decisions, such as risk and associated costs including the potential large societal costs associated with outages. Probabilistic assessments are a valuable means to assess system risk, reliability and associated costs/benefits for various system improvement options particularly for major projects such as those under review. MHI has determined that making these types of decisions without this information is a gap in Nalcor's work to date and recommends that these studies be completed. Such studies would also enable Nalcor to compare the relative reliability between the two options.

- AC Integration Studies

The ac integration studies which have been conducted previously were for a Gull Island development with a 1600 MW three terminal HVdc system linking Labrador to Newfoundland and New Brunswick. Significant changes have been made to the overall project definition but the system integration studies that would support the changes have not been completed. As a result, the full requirements for the integration of the revised Labrador-Island HVdc Link with the ac system on the island are not known. There are additional risk factors that may impact the cumulative present worth of the Infeed Option such as a requirement for additional transmission lines or upgrades, standby generation, or other major equipment.

Good utility practice requires that these integration studies be completed as part of the project screening process (DG2). MHI considers this a significant gap in Nalcor's work to date. These integration studies must be completed prior to project sanction (DG3).

- NERC Standards

A number of findings discuss the applicability of NERC standards in the definition and application of good utility practices, particularly when evaluating Nalcor's practices in the area of reliability. As a guiding principle, MHI used these standards as a metric for assessing whether best practices were followed.

MHI has determined that a majority of utilities in Canada have adopted the definition of "good utility practice" that incorporates adherence to NERC standards. Nalcor does not currently comply. With development of the Maritime Link and Nalcor's participation in the electricity market, NERC standards will ultimately apply. MHI recommends that Nalcor complete a self-assessment to prepare for compliance to NERC standards with or without the Maritime Link.

- Transmission Line Design Criteria

Given the significance of the Labrador-Island Link HVdc transmission line for serving the load on the Island of Newfoundland, Nalcor has gathered significant historical metrological data in accordance with the IEC and CSA Standards. Exhibit 30 indicates that Nalcor has selected a 1:50-year reliability return period which is inconsistent with the recommended 1:500-year reliability return period outlined in the IEC and CSA Standard for this class of transmission line without an alternate supply. In the case where an alternate supply is available, e.g. the Maritime Link or backup generation, then the 1:150-year reliability return period is acceptable. Nalcor has stated that the additional capital cost increase for the 1:150-year return period for the transmission line would be \$150 million. In the latter case, Nalcor should also give consideration to an even higher level reliability return period in the remote alpine regions. MHI recommends that Nalcor adhere to these criteria for the HVdc transmission line design.

MHI finds that the Muskrat Falls Generating Station and the Labrador-Island Link HVdc projects represent the least-cost option of the two alternatives, when considered together with the underlying assumptions and inputs provided by Nalcor.

With projects of this magnitude, and considering the length of the analysis period, there are risks and uncertainties associated with the key inputs and assumptions. Changes in these key inputs and assumptions will affect the financial results and must be assessed to determine materiality. These changes in key inputs and assumptions can impact the results of the analysis and shift the preference for what is the least cost option. Fuel costs and construction material costs are variable with world economic conditions. Load forecasts are a major input based on local conditions and must be carefully monitored to ensure that generation development occurs in compliance with future load requirements. Analyses were completed to demonstrate the sensitivity of the cumulative present worth results to material changes to key inputs and these are outlined in this report.

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1 Introduction

In June 2011 the Government of Newfoundland and Labrador requested that the Board of Commissioners of Public Utilities of Newfoundland and Labrador (Board) review and report on whether Nalcor's proposed Muskrat Falls and Labrador-Island HVdc Link projects are the least cost option for the supply of power and energy to the Island of Newfoundland. The Government's request, in the form of a Reference Question, was stated as follows:

"The Board shall review and report to Government on whether the Projects represent the least-cost option for the supply of power to Island Interconnected Customers over the period of 2011-2067, as compared to the Isolated Island Option, this being the 'Reference Question'.

In answering the Reference Question, the Board

- shall consider and evaluate factors it considers relevant including NLH's and Nalcor's forecasts and assumptions for the Island load, system planning assumptions, and the process for developing and comparing the estimated costs for the supply of power to Island Interconnected Customers; and*
- shall assume that any power from the Projects which is in excess of the needs of the Province is not monetized or utilized, and therefore the Board shall not include consideration of the options and decisions respecting the monetization of the excess power from the Muskrat Falls generation facility, including the Maritime Link Project."*

It should be noted that the investigation of alternative fuel types, other island supply options, consideration of the export market via the Maritime Link, the technical feasibility of the Maritime Link, electricity requirements in Labrador as well as potential impacts on island rates were not included in the review by the Terms of Reference.

The Board engaged Manitoba Hydro International Ltd. (MHI) as its independent expert to assist the Board in its review.

This section of the Report briefly describes MHI, the process of consultant selection, the MHI Team, Nalcor, and the two options that were to be compared. The balance of Volume I provides the high level summaries of the various detailed technical and financial analyses completed, with detailed reports contained in Volume 2: Studies.

1.1 Manitoba Hydro International

MHI is a wholly-owned subsidiary of Manitoba Hydro, one of the largest and oldest electric power utilities in Canada. MHI provides consulting services to power utilities, governments, and private sector clients worldwide to assist them in the delivery of electricity efficiently, effectively, and in a sustainable manner. In the execution of its projects, MHI has provided utility infrastructure management, consulting, and training services to over 60 countries worldwide.

MHI has established itself as an ethical, environmentally responsible provider of high-quality utility services to the international power sector for the past 25 years.

1.2 Board of Commissioners of Public Utilities, Newfoundland and Labrador

The Board is an independent, quasi-judicial tribunal constituted under the *Public Utilities Act*. It is responsible, among other things, for the regulation of and general supervision of public utilities in the Province of Newfoundland and Labrador. In regulating the utilities in the province, the Board ensures that the rates charged are just and reasonable, and that the service provided is safe and reliable.¹⁴

1.3 Request for Proposal, Response, and Contract Award

MHI was selected by the Board after a competitive request for proposal (RFP) process by invitation. The RFP and the proposal filed by MHI are available on the Board's public website. The Board awarded the contract to MHI on July 4, 2011.

1.4 The MHI Team

MHI established a team of technical and financial experts to undertake the required reviews and analyses. The team members are experienced in the design of hydroelectric plants and HVdc systems, project management, operation and maintenance of hydroelectric plants, operation and maintenance of HVdc systems, design and operation/maintenance of thermal plants, transmission line design, transmission system planning and operations, commercial utility operations, load forecasting, and financial management and modelling. An outside firm CESI, with expertise in submarine cables, was contracted to review the details of the engineering, construction, and operation and maintenance of the Strait of Belle Isle crossing. Additional subject matter experts from Manitoba Hydro, and some internal MHI support were also engaged when required. Key members of the team and their respective roles are shown in Figure 2.

¹⁴ Board of Commissioners of Public Utilities of Newfoundland and Labrador, Mandate

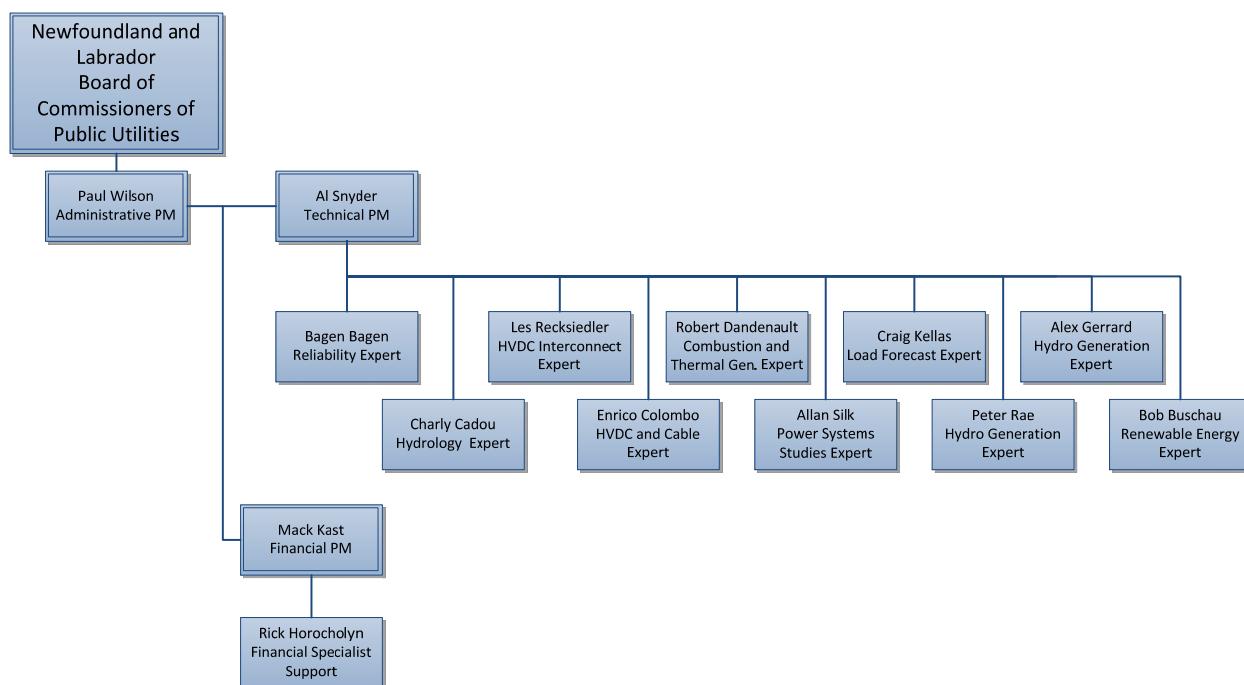


Figure 2: MHI Project Organization Chart

Team member biographies are available in Volume 2, Section 13 – Team and Qualifications.

1.5 Nalcor

Nalcor Energy (Nalcor) is a provincial Crown Corporation, enacted by legislation (*Energy Corporation Act*) and charged with managing, serving, utilizing, and commercializing the oil, gas, and electricity energy assets of the province of Newfoundland and Labrador.

Nalcor is organized into five lines of business, of which three are relevant to this review as shown in Figure 3.

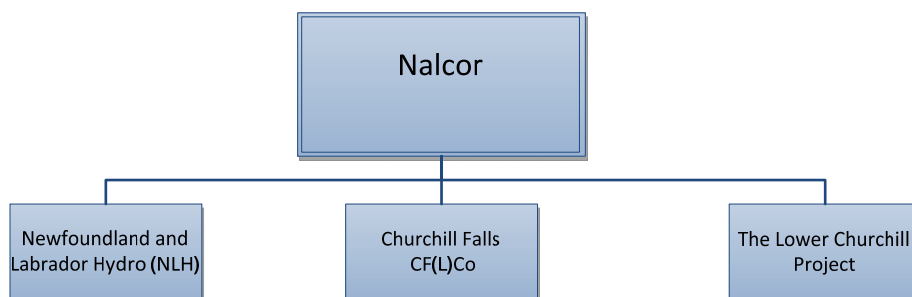


Figure 3: Nalcor Business Lines

1.5.1 Newfoundland and Labrador Hydro

Newfoundland and Labrador Hydro (NLH) is the principal generation and transmission operating company for Newfoundland and Labrador. It also operates distribution assets, primarily in rural areas of the province. Although NLH directly serves over 36,000 residential and commercial customers in approximately 180 communities across the province, it is primarily a bulk generation and transmission utility, with Newfoundland Power as its largest customer. NLH also operates 21 diesel systems to provide service to over 4,300 customers in isolated communities throughout coastal areas of Newfoundland and Labrador. Both utilities operate under the jurisdiction of the Board, which has regulatory authority over rates, policies, and capital expenditures.

Newfoundland Power is an investor-owned company operated by Fortis Inc. It serves approximately 243,000 customers in Newfoundland. Newfoundland Power also operates 140 MW of island generation as part of the energy mix available on the island, and purchases the remainder from NLH.

Figure 4 shows the current configuration of the provincial generation and transmission system.¹⁵

1.5.2 Churchill Falls – CF(L) Co

Nalcor controls 65.8% of the shares of Churchill Falls (Labrador) Corporation Limited, the owner of the 5,428 MW Churchill Falls Generating Station situated on the Upper Churchill River in Labrador. Hydro Quebec controls the remaining shares.

1.5.3 Lower Churchill Project

The Lower Churchill Project is intended to develop the approximately 35% of the Churchill River that has not already been developed by the Upper Churchill Falls Generating Station. The Lower Churchill Project is responsible for developing installations at Gull Island and Muskrat Falls.

¹⁵ Exhibit 102, Nalcor, "Provincial Generation and Transmission Grid", January 2011.



Figure 4: Newfoundland and Labrador Generation and Transmission System Map

1.6 Options Reviewed

The province of Newfoundland and Labrador has extensive viable sources of energy that may be developed¹⁶. Newfoundland's electrical power system on the island presently has no interconnections to any other electrical system on the mainland. The planned Muskrat Falls Generating Station and Labrador-Island Link HVdc system would be the first mainland interconnection via Labrador.

The Reference Question defined the two options to be reviewed which are focused solely on the island of Newfoundland and its associated power system. These options represent Nalcor's assessment of the two most realistic alternatives available for the long-term supply of least cost power and energy to the Island of Newfoundland. The options, which utilize Nalcor's portfolio of potential generation assets and supply scenarios, are described as follows, with corresponding development time frames.

1.6.1 Infeed Option

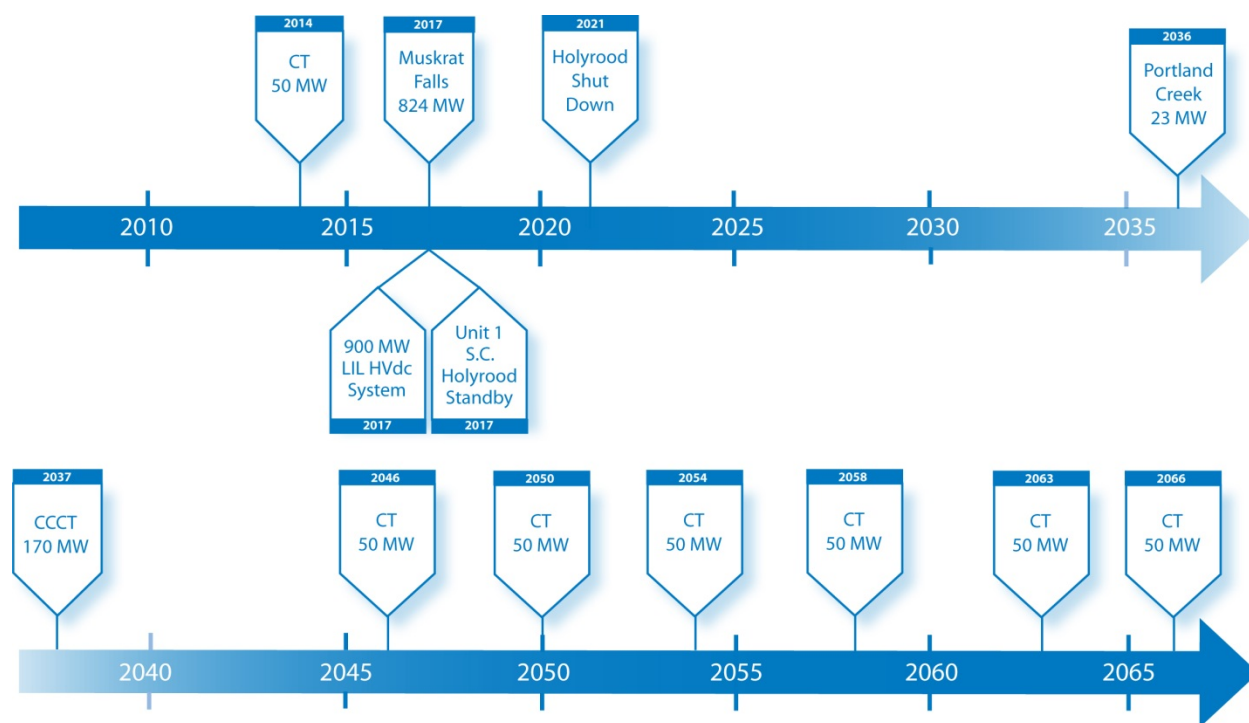


Figure 5: Project Timeline – Infeed Option

The timeline for the evaluation of the Options extends to 2067, which is 50 years past the in-service date of Muskrat Falls Generating Station and the Labrador-Island Link HVdc system¹⁷. From 2036 to 2067, new energy and capacity requirements will be met by adding the hydroelectric Portland Creek Generating Station (23MW), several 170 MW CCCTs, and 50 MW CT thermal energy sources.

¹⁶ Government of Newfoundland and Labrador, "Focusing our Energy: Newfoundland and Labrador Energy Plan", 2007

¹⁷ Exhibit 7, Nalcor, Service Life - Retirements.

Throughout this report, Muskrat Falls Generating Station and the Labrador-Island Link are also referred to as the “Infeed Option”, or in the case of the HVdc system only, the “Labrador-Island Link HVdc system”.

If the Infeed Option is developed, expenditures that result in a cumulative present worth (CPW) of more than \$6.6 billion (2010\$) will be required over the study period to 2067. Given the large output of Muskrat Falls Generating Station, averaging 4.9 TWh per year, excess energy will be available from the station for more than two decades. Any consideration of the monetization of this excess energy was excluded from the scope of this review by the Terms of Reference.

1.6.2 Isolated Island Option

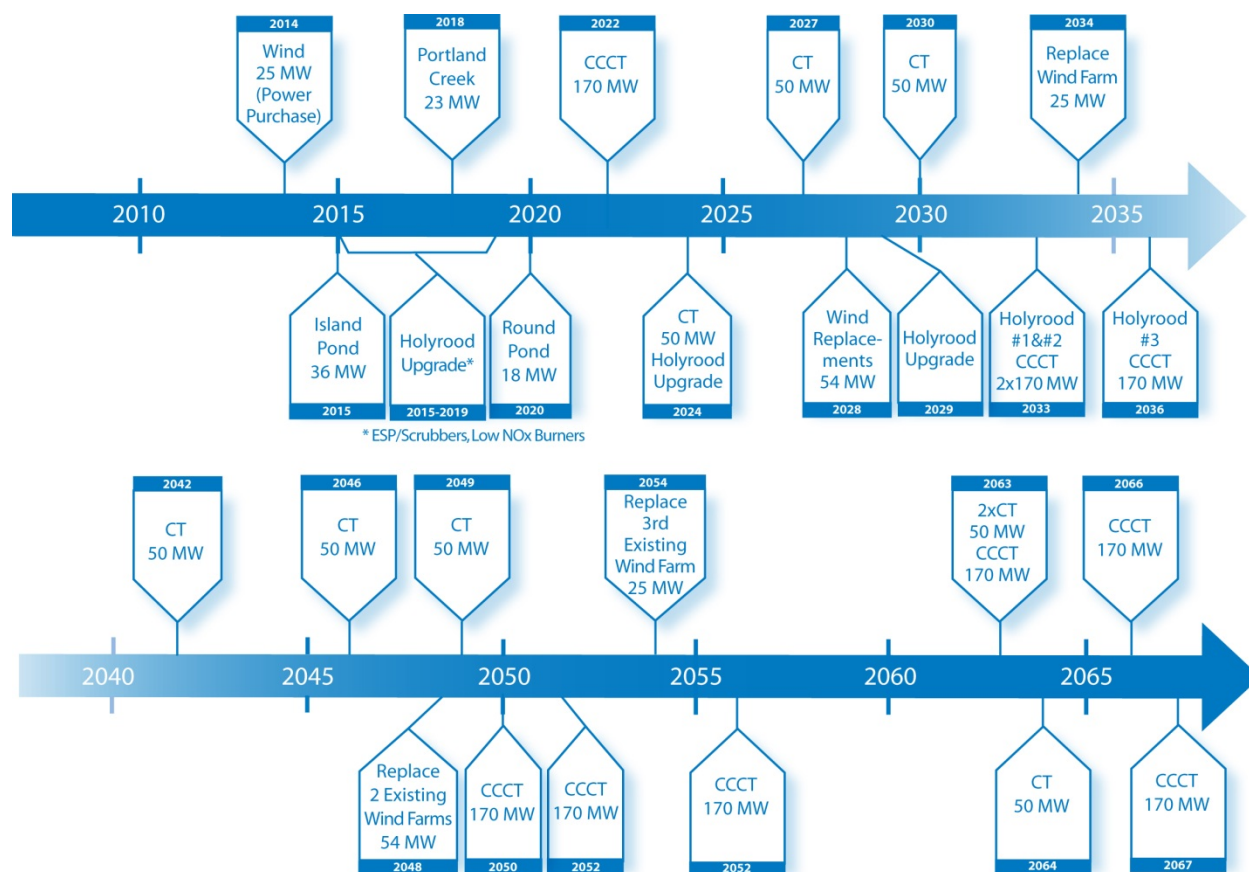


Figure 6: Project Timeline – Isolated Island Option

The Isolated Island Option has no future planned interconnections to the mainland. The salient points of the Isolated Island Option are as follows:

- Installation of environmental emissions controls at Holyrood Thermal Generating Station (electrostatic precipitators, scrubbers, and NOx burners).
- One new 25 MW wind farm in 2014, and replacement of wind farms after 20 years of operation.
- Three new hydroelectric developments at Island Pond, Portland Creek, and Round Pond, totalling 77 MW.

- New thermal generation totalling 1,640 MW, comprised of seven 170 MW CCCTs and nine 50 MW CTs.
- Replacement of the Holyrood Thermal Generating Station with three 170 MW CCCT generating units (two in 2033 and one in 2036).

If the Isolated Island Option is developed, expenditures that result in a CPW of more than \$8.8 billion (2010\$) will be required over the study period to 2067. Of the \$8.8 billion, \$6 billion will be for the cost of fuel.

1.7 Generation Resource Planning Process

Electric utility generation planning is based on the demand on the system (load forecast) which drives the supply of generation options to satisfy the load requirements. The load forecast is the first step in the planning process, as it establishes the future electricity requirements of customers. Information on future annual energy and peak demand requirements is needed to determine the timing and sizing of future generation sources. The load forecast may be a simple extrapolation of previous load growth, or it may involve large blocks of energy either added or deleted as part of industrial or commercial load start-ups or closures. Accurate load forecasts, together with an appropriate generation resource plan, minimize the risks that range between an inadequate supply and excess generating capacity.

Adding more generation assets requires significant amounts of capital and generally long lead times (particularly in the case of hydroelectric generation), so careful consideration needs to be given to the load forecast before any projects are undertaken. Market factors relating to price and the availability of a reliable electricity supply will have an impact on electricity demand. Load forecasts also depend on the price of energy; thus, each generation resource option may require its own load forecast to properly stage new generation.

The range of options available for generation vary from region to region, based on the supply of natural resources that can be economically harnessed to produce an adequate supply of firm energy and capacity. Firm energy is defined as having sufficient generating capability to meet annual load requirements; capacity is defined as having the ability to meet customers' peak demands. Utilities must plan and build systems to supply both firm energy and capacity.

Generation options include hydraulic river or tidal stations, with or without ponding or storage; thermal generating options fueled by oil, gas, coal, biomass or uranium (nuclear); and wind farms and/or solar farms. The objectives of the review of options are to eliminate those that are not feasible and then to select the most economic mix of generation facilities to match the projected load growth.

Screening supply options normally takes into account the security and reliability of the supply, the costs of energy to the customer, environmental and social considerations, risk and uncertainty, and the financial viability of non-regulated components. The process should consider a minimum 20-year planning horizon, and as a matter of course, re-evaluate options annually or as new information is made available on future load possibilities, new technologies, and planned plant retirements. All preferred supply options undergo a similar rigorous licencing process, which development planning must take into consideration to ensure that the supply is available when required.

Planned generating capacity must not be less than the forecasted firm annual peak energy, plus a reserve requirement determined partly by a resource adequacy study. A reserve requirement of 15 to 20% of forecasted firm loads is typical in North America when using a one day in ten loss of load expectation, and when there is no interconnection to an electrical grid¹⁸. The reserve requirement is normally 10 to 12% when the generation and transmission grid is strongly interconnected with other sources of supply as is the case with Manitoba Hydro.

Demand for energy should consider demand side management programs which are either in place or are contemplated in the near future. Demand side management is treated as if it were generation, as it represents a reduction from the base load forecast. The economics of demand side management programs should be evaluated to ensure that they make a positive contribution to the overall financial well-being of the province. The base load forecast also includes transmission losses associated with serving the domestic load.

Before selecting a generation plan, transmission requirements must be taken into consideration. Generally, the least-cost, technically viable option is selected to support the generation options being considered. Also, transmission facilities must be able to withstand various classifications of contingencies and meet reliability criteria.

All future costs are converted to present day costs through the use of a planning technique known as the CPW of the project. The CPW is the present value of all incremental utility capital and operating costs to reliably meet the load forecast, given a prescribed set of reliability criteria.

Once dependable and available supply options and their costs have been identified, a sophisticated software tool is used to optimize and select a preferred development scheme. The data required usually includes resource limitations, fuel prices, and capital and operating costs. The software tool produces a number of generation expansion plans, including a least cost scenario. In Nalcor's case, the software tool is *Strategist*^{®19}. For other utilities, including Manitoba Hydro, custom in-house tools may be used to lay out various staged resource plans. Results are then reviewed in light of the security of supply required, regional economic and social needs, and environmental considerations, before a final decision is made.

Table 21 in Nalcor's Final Submission, identifies the range of options and eligible technologies considered by Nalcor. The two options reviewed in this report were defined by the Reference Question.

Once the eligible options or alternatives are identified to be included in the generation resource plan, the various feasibility studies, integration studies, cost estimates, schedules, reliability studies, environmental impact studies, and financial resource plans can be developed to define requirements, assess and quantify risks, and obtain approvals.

¹⁸ "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 2011, pg. 31

¹⁹ CE-50 (Public), Ventyx, "*Strategist* Introduction"

1.7.1 Generation Resource Planning Key Finding

MHI reviewed Nalcor's generation resource planning process and found that it is consistent with that of leading North American utilities. The Strategist software used by Nalcor to evaluate and select a preferred generation development scheme is appropriate. It should be noted that the addition of a large industrial load on the island or in Labrador could result in a different generation expansion plan.

2 Review Methodology

2.1 MHI's Review Process

MHI's review was approached from two perspectives, technical and financial. The technical aspects included a review of available engineering and related reports, while the financial review addressed the CPW analysis that Nalcor used to determine and justify the least cost alternative of the two options it considered. Meetings with Nalcor's staff and its consultants were held as required to clarify points raised during the reviews. As well, a formalized request for information (RFI) process was used to ask Nalcor for additional information.

Comprehensive information was gathered on the generation expansion components proposed for each of the two options. Individual experts were assigned to review the project design, specifications, standards, timelines, capacity, retirements, and capital and operating costs for the Muskrat Falls generation facility, the Labrador-Island HVdc Link, including the Strait of Belle Isle crossing, the three smaller hydroelectric projects, the wind projects, and the thermal projects, as related to each of the options. Numerous feasibility reports, engineering assessments, and risk analyses were reviewed. Technical reports were prepared to cover hydrology, load forecast, reliability, and ac system studies. The capital and operating costs of each option were examined for reasonableness, recognizing that in some cases it was necessary to escalate costs forward from previous years, as specified in the studies. The composite costs of the integral parts of the two options were carried into the CPW analysis.

The methodology used to develop the CPW model was reviewed and tested. Projected prices in the fuel price forecast were also reviewed in detail. Various related data inputs were investigated, including the applicable exchange rates, the application of Interest During Construction, the Allowance for Funds Used During Construction, the application of projected Consumers Price Indices, the escalation rates, discount rates, and costs of each of the debt and equity components. An assessment was also conducted on impacts to the CPW results if Nalcor sold energy from Muskrat Falls Generating Station to NLH on a cost-of-service basis rather than under a power purchase agreement.

Sensitivities of the CPW results were tested for changes in key input variables, such as capital costs, load forecasts, and fuel prices.

Numerous RFIs were filed with Nalcor. The responses were reviewed and further requests were made as necessary.

2.2 Review of Cost Estimates and Benchmarks

For the two options, MHI reviewed the base estimate costs, the estimates for contingency, and the escalation allowance costs. Studies and cost estimates for the construction of the Muskrat Falls Generating Station and the Labrador-Island Link date back at least 40 years, and a number of studies have been performed for the projects identified in the Isolated Island Option. Over time, more thorough studies were performed and the cost estimates were updated or refined. Nalcor has

adopted the practices used by the AACE International Recommended Practices No 17R-97, which is recognized as a leading authority in total cost management, including cost estimating standards, practices, and methods²⁰. Capital cost estimates for Muskrat Falls Generating Station and the Labrador-Island HVdc Link were prepared to the class sufficient to support the Decision Gate (DG2) screening process. The key parameters of DG2 include the key timelines, project sequencing, and execution approach. Nalcor considers the capital cost estimates coincident with DG2 to be commensurate with an AACE International Class 4 estimate which has a range of accuracy of +50% to -30%²¹. The cost estimate matures as the level of engineering and project planning advances, coincident with an improvement in forecasting accuracy. The Decision Gate 3 (DG3) or project sanction capital cost estimate is considered by Nalcor to be a Class 3 estimate with a range of accuracy of +30% to -20%.

The issue of cost estimate accuracy has a large bearing on the sensitivities of CPW analyses, as the base cost estimates of the various projects are a direct input into the financial model. Nalcor has published a number of documents on their cost estimate process in responses to RFI PUB-Nalcor-42 and 43.

In the Recommended Practices No 17R-97 guide, there are five classes of cost estimates, with different degrees of accuracy as noted below:

- Class 5: +100% to -50%, Concept Screening
- Class 4: +50% to -30%, Study or Feasibility (DG2 accuracy)
- Class 3: +30% to -20%, Budget authorization (DG3 accuracy)
- Class 2: +20% to -15%, Control or Bid/Tender
- Class 1: +15% to -10%, Check Estimate

Figure 7 shows the amount of variability in estimate accuracy versus project definition.

²⁰ CE-51 Rev.1 (Public), Nalcor, "Technical Note - Muskrat Falls Generation Facility and Labrador – Island Transmission Link Overview Of Decision Gate 2 Capital Cost and Schedule Estimates", August 2011, pg 10

²¹ Response to RFI PUB-Nalcor-42

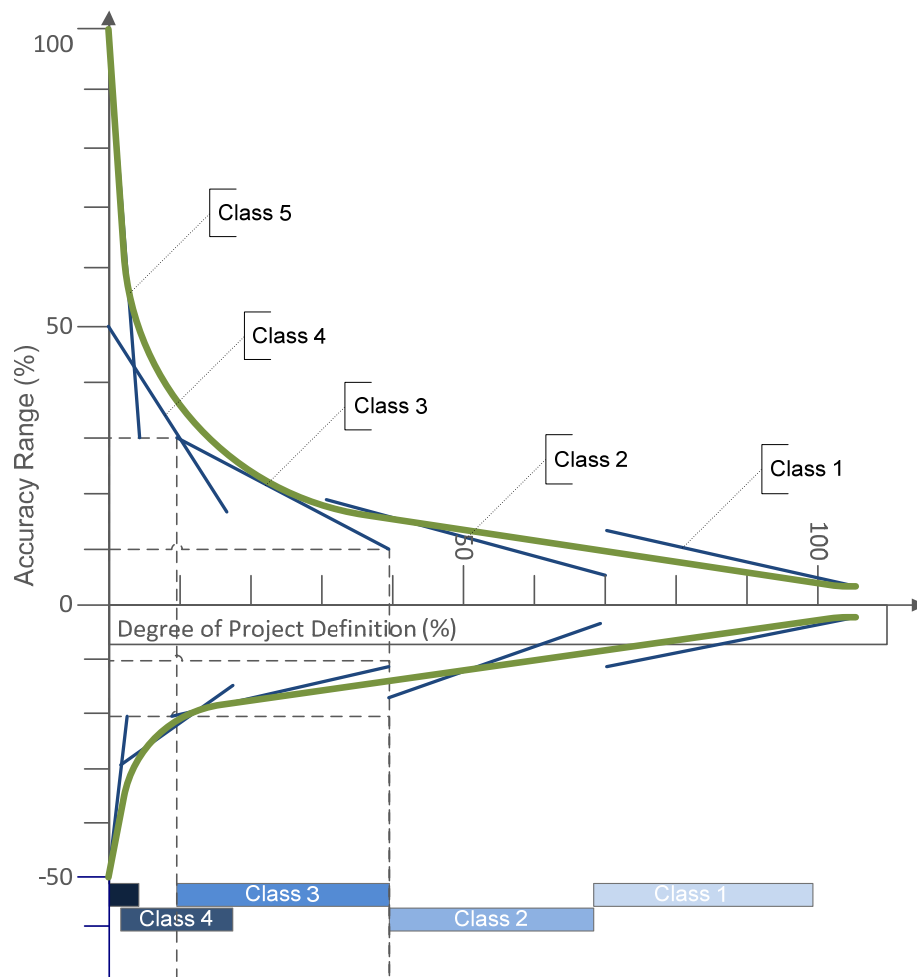


Figure 7: AACE Cost Estimating Accuracy Classes

DG2 used a Class 4 accuracy level, at the study or feasibility stage. At DG3, Nalcor proposes to use a Class 3 accuracy level, for the budget authorization or project sanction stage. Typically, in the early stages of a project's development, a mix of cost estimate classes would be used, as evidenced by what MHI has seen in the case of Muskrat Falls Generating Station or the Strait of Belle Isle marine crossing, which were studied more extensively than other components.

For comparison purposes, Manitoba Hydro uses a staged project development process (Stage I through Stage V). The project components include input from engineering, socio-economic and environmental sources. Confidence in the cost estimate increases as the project progresses through each stage of development due to the increase in the degree of project definition. The risk analysis for contingency determination at each stage of the project uses an appropriate AACE International recommended technique to account for specific project risks, and a contingency developed.

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 projects 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.

MHI reviewed the cost estimation process developed by Nalcor for the Infeed Option. Capital cost estimates were developed by Nalcor from base estimates to which contingency estimates and escalation allowances were added. The base estimates were developed in accordance with the principles found in the AACE International recommendations. Various price and productivity factors were applied by Nalcor to the key inputs to develop the revised base estimates. Nalcor's contingency percentage was evaluated and applied to the base estimate to reflect the impact of definition and performance risks, after which an escalation factor was determined to recognize cost changes associated with changes in productivity, technology, and market conditions. The indices used by Nalcor to develop the escalation provision were based on Global Insight's first quarter 2010 report. Each of the applicable contingency estimates and escalation allowances were applied to each of the base costs of the two options, to develop the costs used to ultimately form the basis of the CPW analyses. Given the timelines for the extended construction schedule, an Allowance for Funds Used During Construction was also capitalized as part of the construction costs.

The costs associated with the projects forming part of the Isolated Island Option were diverse, as they were spread across an extended number of projects, including an upgrade to the Holyrood complex and the addition of three hydroelectric plants, combustion turbines (CT), combined cycle combustion turbines (CCCT), and wind farm projects. The cost estimates for the increments of generating capacity included environmental improvements at Holyrood Thermal Generating Station in compliance with the government mandate that such improvements must proceed if the Isolated Island Option was selected. As the Infeed Option has passed DG2, the associated reports for the Infeed Option are more rigorous than they are for the Isolated Island Option where some of estimates were less detailed.

2.3 Risk Review

MHI reviewed the risk analysis components of all reports and studies for both the Infeed and Isolated Island Options including the "Technical Note – Strategic Risk Analysis and Mitigation"²². Nalcor defined risks into two categories: tactical and strategic for the Infeed Option. Tactical risks were separated into definition risks which evaluated the design and planning aspects of the project, and performance risks associated with contractor performance, weather delays, material pricing etc. Strategic risks include background risks such as changes in scope, market conditions, location factors etc. and organization risks which are associated with the size and complexity of the project.

As a part of the technical reviews, MHI noted that the segments of reports that focused on risk were tied for the most part to the determination of costs, the timing of projects, and ongoing operational

²² CE-52 Rev .1 (Public), Nalcor, "Technical Note: Strategic Risk Analysis and Mitigation", July 2010.

issues. MHI has documented the risks where appropriate throughout this report. Significant items are noted in the Key Findings sections.

2.4 Investigative Reviews

Figure 8 outlines the process steps followed by MHI and project documents required to review the two options leading to two parallel investigations that culminated in the CPW analysis, and development of the key findings.

The review process followed a power resource planning assessment, in that:

- a base load forecast was used to define energy needs;
- several scenarios were formulated to meet the energy needs;
- these scenarios were ranked by corporate approved criteria which may be the least cost (amongst others); and
- the selected option(s) were examined further to refine estimates.

The cumulative present worth analysis with results in 2010 dollars was used to measure the relative costs of the Options, which are based on a number of key inputs, e.g. fuel price, capital cost, and load forecast. These inputs were adjusted to test their sensitivities to the base assumptions.

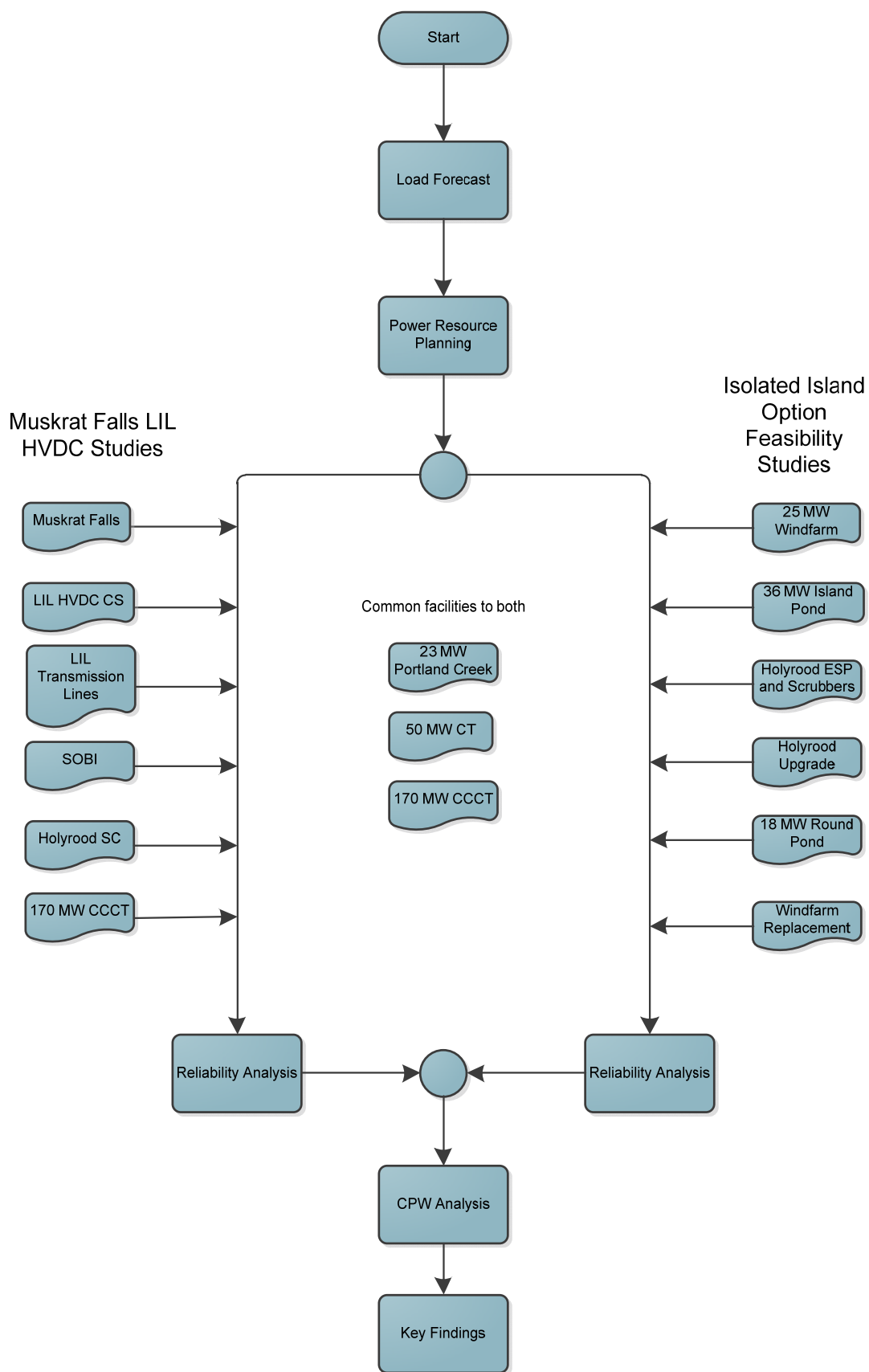


Figure 8: MHI Two Options Review Process

2.5 Technical Review

The technical review included an assessment of prior work available to ensure that Nalcor and its consultants had taken all reasonable steps and followed acceptable practices in developing the two scenarios, cost estimates, schedules, feasibility studies, and risk analyses. Topics covered in MHI's assessment included the generation resource planning process, reliability studies, load forecasts, hydrology studies, hydraulic optimization, power and energy assessments, ac system studies, and the cost estimating methodology.

2.6 Financial Review

In its financial review, MHI evaluated the CPW analysis, which is a financial model and methodology that gauges the cost of an option based on capital costs, operating costs, escalators, fuel pricing, power purchase agreements, and other relevant components staged over time. The Strategist tool that Nalcor used for its CPW analyses is sophisticated and will optimize a resource plan based on available resource options, load forecasts, fuel pricing, and capital and operating costs.

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3 Technical Reviews – Supporting Studies

3.1 Load Forecast

MHI reviewed Nalcor's load forecast to determine if it was conducted with due diligence, skill, and care consistent with acceptable utility practices. The load forecast predicts future electrical energy (GWh) and demand (MW) requirements, and is a critical factor in developing and evaluating future generation options. MHI completed a comprehensive analysis of NLH's load forecasting methods, data sources, and data analysis techniques drawing on material provided by Nalcor through on-site meetings and in responses to several RFIs, particularly MHI-Nalcor-55, 56, and 90 to 93.

The load forecast analysis considered the total electrical energy and demand requirements of the island of Newfoundland, excluding Labrador's requirements, focused on the period of 2010 – 2029. For analytical purposes, the 2010 forecast year was replaced with weather-adjusted actual figures so as to be representative of normal weather. To support the CPW analysis, the load forecast was extrapolated over an extended period (2029-2067). Results of the extrapolated forecast are reviewed only in the total island energy requirements and interconnected island system peak. The load forecasting process was evaluated using criteria that examined the reasonableness of the methodologies and assumptions used to prepare the 2010 Planning Load Forecast. Past forecast performance was measured by examining the accuracy of the last 10 forecasts prepared by NLH.

3.1.1 Energy Forecast Accuracy

Forecasting an uncertain future is a difficult task. Variations between actual and predicted results must be expected. Experience within the industry based on the results from Manitoba Hydro and other Canadian utilities indicate that a reasonable measure for forecast accuracy is a forecast deviation of 1 percent per year into the future. This means that a 10-year-old forecast should be within plus or minus 10 percent of the actual energy load observed. Table 1 measures energy forecast accuracy in terms of percentage of deviation from the actual load. In order to measure forecast accuracy, historical forecasts are compared to actual weather adjusted results. The Years of History term represents the number of past years used to compare forecast accuracy, thus it can be observed from Table 1 that the January 2001 domestic load forecast originally prepared in 2000 (with ten years of historical observation) was 10% low. This table shows that the past forecast results for the domestic and line loss sectors were reasonable and that the general service forecast has performed extremely well. Previous load forecasts assumed that the pulp and paper industry would continue operations at normal energy consumption levels, without any mill closures. However, those unforeseen closures of two mills caused a severe effect on the industrial forecast and have adversely impacted the total island energy forecast results.

Table 1: Energy Forecast Accuracy by Service Class (%)

Energy Forecast Accuracy Measured in Percentage of Deviation from the Actual Load										
Years of History	1	2	3	4	5	6	7	8	9	10
Domestic	-1.3%	-2.2%	-3.3%	-3.8%	-4.0%	-4.7%	-5.8%	-6.9%	-7.9%	-10.0%
General Service	0.1%	0.0%	0.0%	0.1%	0.3%	0.4%	0.4%	1.0%	2.0%	6.0%
Industrial	5%	14%	27%	37%	50%	67%	76%	92%	119%	124%
Line Losses	-2.5%	-3.8%	-4.5%	-6.2%	-6.6%	-6.7%	-5.6%	-4.6%	-3.4%	-4.1%
Island Energy	0.4%	1.9%	3.7%	5.5%	7.9%	10.6%	11.4%	13.3%	16.6%	17.4%

In terms of electrical energy (GWh), Table 2 shows that virtually all of the total island energy forecast deviations are associated with the high industrial forecast.

Table 2: Energy Forecast Accuracy Measured in GWh of Deviation from Actual Load

Energy Forecast Accuracy Measured in GWh of Deviation from Actual Load										
Years of History	1	2	3	4	5	6	7	8	9	10
Domestic	-43	-72	-109	-125	-133	-157	-199	-240	-277	-353
General Service	-1	0	0	3	7	8	8	22	44	134
Industrial	88	238	423	586	775	1,007	1,105	1,266	1,505	1,565
Line Losses	-15	-22	-26	-38	-39	-32	-32	-27	-20	-24
Island Energy	29	144	287	428	611	819	881	1,022	1,252	1,321

3.1.2 Peak Forecast Accuracy

Table 3 measures forecast accuracy in terms of percentage of deviation from the actual peak load observed. It also shows that the Newfoundland Power (NP) peak forecast results are excellent. The “other” peak forecast, which includes the peak demand associated with NLH’s rural system, transmission system losses and industrial customers, has not performed well. The interconnected island system peak demand forecast is prepared by summing the two sector forecasts. As a result, the “other” peak demand forecast has adversely affected the overall results for the interconnected island peak due to the high industrial forecast.

Table 3: Peak Forecast Accuracy (%)

Peak Forecast Accuracy Measured in Percentage of Deviation from the Actual Load										
Years of History	1	2	3	4	5	6	7	8	9	10
NP Peak	2.1%	0.7%	1.0%	0.6%	1.0%	1.2%	1.3%	0.6%	0.2%	2.5%
Other Peak	1.5%	5.2%	12.3%	19.6%	25.1%	35.3%	37.2%	46.9%	57.7%	96.7%
Island Peak	1.7%	1.6%	3.3%	4.5%	6.0%	8.0%	8.3%	9.4%	10.4%	17.8%

In terms of electrical demand (MW), Table 4 shows that almost all of the interconnected island peak forecast deviation can be associated with the high “other” peak demand forecast.

Table 4: Peak Forecast Accuracy (MW)

Peak Forecast Accuracy Measured in MW of Deviation from Actual Load										
Years of History	1	2	3	4	5	6	7	8	9	10
NP Peak	22	8	12	7	12	15	15	6	2	30
Other Peak	-15	-4	15	35	52	84	90	116	132	201
Island Peak	7	4	27	42	64	98	105	122	134	231

3.1.3 Load Forecast Summary

The domestic forecast is prepared using a combination of econometric models that predicts the number of customers and average use. The accuracy of the methodology is within acceptable limits, but the forecasting process is biased towards under predicting future consumption. Comparison of forecast versus actual weather-adjusted consumption indicated that the domestic forecast under predicted energy consumption in 53 out of 55 cases examined. The main model, which predicts the average use of a customer in the Newfoundland Power service area, is driven by growth in the number of electric space heating customers. The model does not explain electricity growth from any other domestic end-use. The model has some good points factoring in the effects of marginal electricity prices and technological change, but space heating (although very important) is not the only reason that the average use has increased in the last 40 years.

The general service forecast is prepared using a combination of econometric modeling and linear extrapolation techniques. The main model, which predicts the electricity consumption in the Newfoundland Power service area, is driven by growth in GDP and commercial business investment. The accuracy analysis indicated that this methodology has performed extremely well in the past, producing forecasts that are only 1-2% out, as far as 8 to 9 years into the future. The general service forecast is not biased, under predicting energy consumption 24 times and over predicting energy consumption 31 times out of the 55 cases examined.

The industrial forecast is prepared, on a case by case basis, using direct input from customers on their operational plans. This is a reasonable methodology when considering the small number of industrial customers located on the island. In retrospect, the assumption of continued operation of the pulp and paper plants has been overly optimistic. The industrial forecast has performed poorly in the past because of pulp and paper mill closures that were not accounted for in previous forecasts, even though the industry was facing a reduction in newsprint and paper caused by the internet, a reduction in packaging caused by a shift of manufacturing to China, and increasing low-cost competition from Russia, China, and South America.

In short, the total island energy requirements have been over predicted as a result of one assumption related to the pulp and paper industry that created a high industrial forecast. Otherwise, the total island load forecast has performed extremely well. Table 5 indicates how well the forecast would have performed if the two pulp and paper mill closures, in hindsight, were accounted for in the load forecast.

Table 5: Energy Forecast Accuracy Future Years Island Energy (%)

Forecast Accuracy Measured in Percentage of Deviation from the Actual Load										
Years of History	1	2	3	4	5	6	7	8	9	10
Island Energy	-1.2%	-1.4%	-0.8%	-0.6%	-0.3%	1.0%	1.0%	1.5%	2.0%	2.9%

The Newfoundland Power peak demand regression equation accounts for 80% of the interconnected island demand and has performed extremely well. However, the interconnected island system peak demand has been over predicting as a result of a high industrial peak demand forecast. If the two pulp and paper mill closures were accounted for in the load forecast, Table 6 shows that the accuracy of the interconnected island system peak demand forecast would be similar to the accuracy of the Newfoundland Power peak demand forecast.

Table 6: Energy Forecast Accuracy Future Years NP Peak (%)

Forecast Accuracy Measured in Percentage of Deviation from the Actual Load										
Years of History	1	2	3	4	5	6	7	8	9	10
NP Peak	2.1%	0.7%	1.0%	0.6%	1.0%	1.3%	1.3%	0.6%	0.2%	2.5%

The main issue with the peak forecasting methodology is that the system peak is being calculated separately from the energy portion of the forecast. The current peak forecasting process predicts a future load factor of 58%. There is a possibility that the load factor could drop below forecasted levels as low load factor electric space heat is continually added to the system and space heating efficiency improvements (e.g. insulation upgrades) become more difficult to achieve in the future.

3.1.4 Load Forecast Key Findings

A detailed analysis of load forecasting practices, methodologies and results has led to the following key findings:

1. The load forecasting process is conducted with due diligence, skill and care and meets acceptable utility practices with the exception that end-use modelling techniques for domestic loads are not currently employed.
2. The load forecasting process has produced reasonable results for the domestic and line loss sectors, excellent results for the general service sector, and very poor results for the industrial sector. The industrial sector has adversely affected the overall energy and peak forecast results. In hindsight, if the pulp and paper mill closures were accurately forecasted, the energy and peak forecasts would have been excellent.

3. The domestic sector forecast consistently under predicts future energy needs at a rate of 1% per future year. Although the magnitude of the forecast error is acceptable, the frequency of under predicting energy consumption is a concern. The domestic forecasting process is inherently biased towards under predicting energy consumption.
4. In the next ten years, the load forecast performance should produce good results, if the remaining pulp and paper mill remains operational. The forecast may slightly under predict electricity requirements because of a relatively conservative domestic forecast and an upward revision of 90 GWh for the Vale expansion (not included in the forecast being reviewed). Conversely, the load forecast will significantly over predict electricity requirements, if the remaining pulp and paper mill closes.
5. In the long term, if the remaining pulp and paper mill stays operational, the load forecast is likely to under predict future requirements because the domestic forecast is relatively conservative and the industrial forecast does not include any new loads for the study period.

3.2 Hydrology Studies

MHI reviewed Nalcor's various hydrology studies to determine if they were conducted with due diligence, skill, and care consistent with acceptable utility practices.

The hydrological/hydraulic and energy production review of the studies carried out was an examination of Muskrat Falls and the three on-island hydroelectric projects for relevance of input source, methodology, accuracy of estimates and/or assumptions, identification of gaps, recommendations and findings, and examination of quality assurance mechanisms.

The evaluation was carried out by reviewing available documentation since the inception of the various projects under consideration.

Volume 2 – Section 2, Hydrology Studies covers all reviews of hydrological/hydraulic and energy production studies related to the various plants. The studies are far more extensive for Muskrat Falls than for the other three hydroelectric plants. Topics covered in the Muskrat Falls studies are:

- Hydraulic Modeling of Churchill River
- Construction Flood Estimate
- Probable Maximum Flood
- Spillway Design
- Hydraulic Modelling of Structures
- Dam Break Analysis
- Ice Studies
- Energy Estimates

The Muskrat Falls studies were comprehensive and detailed, with no apparent weaknesses identified. However, some of the analyses need to be finalized as part of the detailed design:

- Finalization of spillway design in accordance with the latest probable maximum flood results and results of 3-D modeling of structures;
- Routing of probable maximum flood flows to test final spillway design;
- Evaluation of the need to increase the proposed diversion capacity at Muskrat Falls;
- Evaluation of the potential effects of ice breakup on construction activities;
- Possible modification of the design in the form of adding a wing wall between the powerhouse intake and spillway;
- Estimation of the cost of damages caused by probable maximum flood flows to obtain the total cost of damages of a dam break while re-routing the flows.

Both the Round Pond and Island Pond projects are part of the Bay d'Espoir hydraulic system. The relevant hydrological parameters of both projects, in particular the probable maximum flood results

and a 37-year flow sequence for energy studies, were estimated in a general Bay d’Espoir regulation study carried out in 1985 by Acres²³.

Because the Round Pond study is more than 25 years old, it should be reviewed in light of new data and the possibility of a change in the operation of the Bay d’Espoir System. Since the probable maximum flood part of the study was carried out before current Canadian Dam Association guidelines took effect, possible implications of the guidelines for the probable maximum flood estimate should be investigated.

For the Island Pond project, should the Round Pond flood hydrology require an update, it may be necessary to reassess the ability of the diversion canal from Island Pond into the Meelpaeg Reservoir to pass an updated probable maximum flood.

A feasibility study of Portland Creek hydropower development was completed in 2006 by SNC-Lavalin. This study is considered adequate to proceed to detailed design. However, the design flood selected as the 1:1000 year flood was estimated from a limited sample of 22 observations. It is possible that a regional flood analysis, such as an Index Flood Method, would provide a more robust estimate.

The results of power and energy studies provide reasonable estimates of the capability of the four hydroelectric developments which are presented in Table 7 below.

Table 7: Hydroelectric Plant Energy and Capacity²⁴

	Muskrat Falls	Round Pond	Island Pond	Portland Creek
Installed Capacity (MW)	824	18	36	23
Firm Energy (GWh)	4,540	108	172	99
Average Energy (GWh)	4,910 ²⁵	139	186	142

3.2.1 Hydrology Key Finding

The key finding from the hydrology reviews is as follows:

- The Muskrat Falls studies were conducted in accordance with utility best practices, comprehensively, and with no apparent demonstrated weaknesses. Also, the energy and capacity estimates for Muskrat Falls and the three small hydroelectric facilities on the island, which were prepared by various consultants using industry accepted practices, were reviewed and confirmed to be reasonable for DG2.

²³ Exhibit 54, ACRES, “Bay d’Espoir Flood Analysis and Alternatives Study”, December 1985

²⁴ “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 2011.

²⁵ Without Gull Island

3.3 Power System Reliability Studies

MHI reviewed material available from Nalcor on reliability studies to determine if they were conducted with due diligence, skill, and care consistent with acceptable utility practices. The documentation included:

- Studies and reports on resource planning;
- The Strait of Belle Isle cable crossing;
- The Labrador-Island Link HVdc system overhead line;
- Reliability studies of HVdc schemes; and
- Other related information.

In the design, construction, and operation of electrical power systems one important consideration is whether the system will provide a reliable supply of electricity to meet the needs of the customers. There are many ways to define and characterize reliability and, by any metric used, additions to a power system should not degrade the reliability performance of the system. As the Island of Newfoundland is currently isolated electrically, investigations on reliability are one of the primary concerns.

Reliability evaluation methods can be classified into two categories: deterministic and probabilistic. Deterministic methods are subjective and based on engineering judgement. Industry practitioners largely use deterministic methods as they are simple and intuitive. However, elements of power system behaviour are unpredictable and random in nature. Also, power systems are increasing in complexity. Thus, probabilistic reliability methods applied to modern power systems are an improved and more accurate method for reliability assessment. Deterministic techniques are being augmented by probabilistic methods particularly for significant projects²⁶ by leading North American electric power entities; Manitoba Hydro, BC Hydro, Hydro Quebec, Hydro One in Ontario and the Northeast Power Coordinating Council, Inc. (NPCC) have all adopted probabilistic methods to establish system reliability metrics. Industry working groups, which provide guidance to reliability practitioners, are now recommending that these methods be adopted as industry wide standards.

Available documentation on the reliability aspects of the two alternatives prepared by Nalcor and its consultants has been reviewed. These documents include studies and reports on resource planning, the Strait of Belle Isle cable crossing²⁷, the Labrador-Island Link HVdc system overhead line²⁸, Power Technologies Inc. (PTI) probabilistic reliability studies on different HVdc schemes²⁹ and other related information. The forced outage rates assumed for various types of generating units are based on reliable data sources and reasonable assumptions. The procedures and methodologies proposed by PTI in the early 1980's for the development of the HVdc system reliability model are still valid and

²⁶ R. Billinton, J. Satish, "Adequacy Evaluation in Generation, Transmission, and Distribution Systems of an Electric Power System", 1993, IEEE 0-7803-1319-4/93

²⁷ Exhibit 35, C-CORE, "Iceberg Risk to Subsea Cables in Strait of Belle Isle", June 2011

²⁸ Exhibit 106, Nalcor, "Technical Note: Labrador — Island HVdc Link and Island Interconnected System Reliability", October 2011

²⁹ Exhibit 48, PTI, "Newfoundland and Labrador HVdc Project HVdc Link Reliability Studies", June 1981

could have been used for modeling the proposed Labrador-Island Link HVdc system with appropriate modifications.

A probabilistic adequacy study that includes transmission considerations for comparison of the reliability of the two options has not been performed by Nalcor. This is a gap in Nalcor's planning practices. The Labrador-Island Link HVdc forced outage rate of 0.89% per pole assumed for some of the analysis should be replaced by a more advanced and comprehensive reliability model incorporating all components of the Labrador-Island Link HVdc system, and taking into account all risk factors experienced in operations of the system. Probabilistic reliability methods utilize standard terms and indices such as Loss of Load Expectation (LOLE), or Expected Unserved Energy (EUE), and make the risk analysis results plainly understandable in terms of dollars, or loss of load.

A probabilistic adequacy study would include data on the HVdc converter equipment together with the overhead transmission line and submarine cable. The entire HVdc system could experience pole or bipole outages, in some cases for extended periods of time. These risks and contingencies can be mitigated through appropriate design and specification of the HVdc system components.

The first task of a power system reliability study would be to determine component outage models. Following the development of appropriate component reliability models, the next step is to incorporate the models into a system reliability evaluation study. These system studies use various indices to measure the risk inherent in a particular power system configuration.

3.3.1 Component and Sub-system Reliability Modeling

The components and/or subsystems that should be modeled in a probabilistic reliability assessment usually consist of generating units and major transmission facilities. The average performance data from the 2004 Canadian Electricity Association's Annual Report on Generation Equipment Status is used to develop forced outage rates (FOR) for various types of generating units. Although no detailed information is available for review on the reliability of the Labrador-Island Link HVdc system converter stations, reliability data from manufacturers or collected from similar systems may be used to model converter station components³⁰. Developing the probabilistic model would involve:

1. A review of the operating history of similar installations around the world;
2. An estimate of specific risks, such as: icebergs, fishing dredges, and ocean currents for the Strait of Belle Isle cable crossing; and rime ice and salt contamination for the overhead HVdc line;
3. An evaluation of the reliability of the proposed cable, overhead line, and converter stations; and

³⁰ M. G. Bennett, N. S. Dhaliwal and A. Leirbukt, "A survey of the Reliability of HVdc Systems Throughout the World 2007-2008", 43rd CIGRE Session, Aug 22-Aug 27, 2010, Paris, France.

4. Merging the component reliability models to form an overall Labrador-Island Link HVdc system reliability model.

3.3.2 Reliability Comparison of the Two Options

The proposed Labrador-Island Link HVdc system is a vital component of the Infeed Option. The impacts of the HVdc link on overall system reliability should, therefore, be quantitatively evaluated to provide required inputs to the decision-making process. The impact of the proposed Labrador-Island Link HVdc system can be quantified in terms of the commonly used reliability indices of load carrying capability, loss of load expectation, or expected unserved energy. However, no such probabilistic study results were available for review and MHI recommends that these studies be carried out as part of the planning process.

3.3.3 Summary

The forced outage rates assumed in the documentation for various types of generating units are reasonable. The source documents for the development of probabilistic reliability models for the proposed Labrador-Island Link HVdc system are available. The procedures and methodologies proposed by PTI for the development of the HVdc system reliability model are still valid and can, with appropriate modifications, be used for modeling the proposed Labrador-Island Link HVdc system.

The following system reliability studies and documentation were not performed and must be completed: quantification of the impact of the Labrador-Island Link HVdc system on overall system reliability; a comparison of the two options in terms of reliability considering the Labrador-Island Link HVdc system performance; and the reliability cost implications.

3.3.4 Power System Reliability Key Findings

The following key findings are noted:

1. The forced outage rates (FOR) assumed for various types of generating units are based on reliable sources and considered to be reasonable. The information documenting the derivation of the Labrador-Island Link HVdc system FOR of 0.89% on a per pole basis was not available for MHI's review. MHI has compared the Labrador-Island Link HVdc system pole FOR of 0.89% with published information and that of Manitoba Hydro's HVdc system and finds it within the normally accepted range. However, this FOR should be replaced by a more advanced and comprehensive reliability model incorporating all components of the Labrador-Island Link HVdc system.

2. Probabilistic adequacy studies including transmission considerations, have not been performed for comparison of the reliability between the two options. This is a gap in Nalcor's practices as several Canadian utilities, NERC regions and members have adopted these probabilistic methods for reliability studies particularly for major projects. Probabilistic reliability methods utilize standard terms and indices such as Loss of Load Expectation, or Expected Unserved Energy, and make the risk analysis results plainly understandable in terms of dollars and/or loss of load.

Deterministic assessments, such as those performed by Nalcor, cannot quantify the true risks associated with a power system and are unable to provide some of the important inputs for making sound engineering and business decisions. Factors such as risk and associated costs including the potential large societal costs related to outages were not evaluated. Probabilistic assessment is a valuable means to assess system risk, reliability and associated costs/benefits for various system improvement options particularly for major projects proposed by Nalcor. MHI has determined that choosing between the two options under review without such an assessment is a gap in Nalcor's work to date. Typically, these studies are completed at DG2. MHI recommends that these probabilistic reliability assessment studies be completed as soon as possible for both options under review. Such studies should become part of Nalcor's planning processes that would allow them to do a comparison of the relative reliability for future facilities.

3.4 Transmission Planning Criteria, AC Integration Studies, and NERC Standards

Nalcor's work in the areas of transmission planning criteria, ac integration studies, and NERC standards as they relate to good utility practice, were reviewed by MHI. The results of this review are summarized in the following sections.

3.4.1 Transmission Planning Criteria

The transmission planning criteria is a critical document that clearly identifies the parameters that trigger when new transmission facilities are required, or existing facilities need to be upgraded. Nalcor provided a document that describes the NLH and Nalcor power system planning criteria³¹. The criterion is applied to the entire power system and is at a very high level. Nalcor also provided a self-assessment on compliance to its transmission planning criteria in Exhibit 42 "Newfoundland and Labrador Hydro 2009 Planning Criteria Review"³².

Ideally, planning criteria should be set out in a high level document that points the reader to supporting documentation which identifies how the criteria will be met. The format used by Nalcor could be improved by making references to its external and internal standards, guidelines, and policies. Otherwise, the transmission planning criteria in use at Nalcor follow utility best practices.

3.4.2 AC Integration Studies

The ac system integration studies made available by Nalcor to MHI for review were conducted for the Gull Island Generating Station and 1600 MW 3-terminal HVdc interconnector, with one termination at Soldiers Pond and another at Salisbury, New Brunswick. The project definition changed in November 2010 following completion of Nalcor's project alternatives screening study (DG2). Nalcor decided to proceed with generation at Muskrat Falls using a point-to-point HVdc transmission system (Labrador-Island Link) with the inverter at Soldiers Pond. The response to RFI MHI-Nalcor-44 indicated that the ac integration studies for the current configuration would be completed by November 2011, which has now been delayed to the end of March 2012³³. MHI considers this a significant gap in Nalcor's work to date. This information for a large hydroelectric project would normally be available prior to DG2. These ac integration studies must be completed prior to DG3.

Nalcor filed the following documents to describe the transmission assets required to support the interconnections to Labrador and the Maritimes:

- Exhibit 23: Historical Summary of the Labrador-Island HVdc System Configuration for the Lower Churchill Project (1974-Present) – July 2011

³¹ Exhibit 105, Nalcor, System Planning Department, "Transmission Planning Manual", Revision 2, September 2009

³² Exhibit 42, Nalcor, System Planning Department, "Newfoundland and Labrador Hydro 2009 Planning Criteria Review", Dec 2009

³³ Response to RFI PUB-Nalcor-143

- Exhibit CE31 Rev 1: Gull Island to Soldiers Pond HVdc Interconnection DC System Studies – December 1998
- Exhibit CE03/CE04 Lower Churchill Project DC1020 HVdc System Integration Study Volumes 1 and 2 – May 2008
- Exhibit CE10: Lower Churchill Project DC1210 HVdc Sensitivity Studies – July 2010

With the redefined project definition, these studies do not adequately describe the facilities required to successfully operate the transmission system under the new configuration. As such, there may be unidentified risks in proceeding with this project at this time. For example, the studies could identify the requirement for additional back-up generation, new transmission, enhanced protection schemes, or other system additions.

Nalcor did supply a study plan which described the scope of activities to be undertaken in the various ac integration studies and contains, modes of operation, criteria, and a number of contingencies to test the performance of the integrated system³⁴. For example, a three-phase fault or slow clearing single-phase-to-ground fault close to the converter station could cause a temporary block of the Labrador-Island Link, which would impact the Newfoundland power system.

The response to RFI PUB-Nalcor-144 indicates that the final integration studies for the Infeed Option are being completed in two stages: first the Infeed Option is being studied without the Maritime Link, and then, as a second stage, the Maritime Link will be included.

3.4.3 AC Integration Studies Key Finding

The key finding from the ac integration studies review is as follows:

- System integration studies completed as part of the project alternatives screening process, and provided to MHI by Nalcor were for a Gull Island development with a 1600 MW three terminal HVdc system to Newfoundland and New Brunswick. Significant changes were made to the overall project definition with the proposed Muskrat Falls Generating Station development, and the deletion of the New Brunswick link. Integration studies that would support the changes have not been completed and Nalcor now advises that the studies will not be available until March 2012³⁵. As the full requirements for integration of the Labrador-Island Link HVdc system are not known, there may be additional risk factors that may impact the cumulative present worth of the Infeed Option. For example, installation of backup supplies to cover operational limitations in the Labrador-Island Link HVdc system may be required, and additional transmission lines may be needed to maintain acceptable system performance. Spare equipment requirements also need to be taken into consideration. Good utility practice requires that these integration studies be completed as part of the project screening process (DG2). MHI considers this a major gap in Nalcor's work to date. These integrations studies must be completed prior to project sanction (DG3).

³⁴ Response to RFI MHI-Nalcor-39

³⁵ Response to RFI PUB-Nalcor-143

3.4.4 NERC Standards

“Good utility practice” is a policy that most utilities recognize, either voluntarily or by regulation. The principle behind good utility practice is that electric utilities will adopt the practices and methods of a significant portion of utilities within a geographic boundary.

In Canada, eight of the ten jurisdictions have accepted NERC standards as their reliability standards. With near unanimous acceptance of mandatory standards within Canada aimed at increasing the reliability of the provincial networks, NERC standards are now a practice, method or act followed by a significant portion of the electric utility industry. Therefore any utility that is assessing their adherence to good utility practice whether or not it interconnects to the marketplace, must consider their adherence to NERC Standards.

Nalcor currently does not comply with NERC standards^{36,37}. However, should the Maritime Link proceed, and Nalcor participates in the electricity marketplace, NERC standards will ultimately apply. MHI recommends that Nalcor complete a self-assessment and prepare for compliance to NERC standards with or without the Maritime Link.

3.4.5 NERC Standards Key Finding

The key finding from the NERC Standards review is as follows:

- MHI finds that Nalcor currently does not comply with North American Electric Reliability Corporation (NERC) standards. A majority of utilities in Canada have adopted the definition of “good utility practice” that incorporates adherence to NERC standards. Also, should the Maritime Link proceed, and Nalcor participates in the electricity marketplace, NERC standards will ultimately apply. MHI recommends that Nalcor complete a self-assessment and prepare for compliance to NERC standards with or without the Maritime Link.

³⁶ Exhibit 106, Nalcor, “Technical Note Labrador –Island HVdc Link and Island Interconnected System Reliability”, page 33

³⁷ Response to RFI PUB-Nalcor-164

4 Technical Review – Infeed Option

The Infeed Option is largely a hydroelectric generation plan (923 MW by year 2067), with the addition of 520 MW of thermal generation. The following table describes the timing, size, and type of new generation sources added to the island with the Infeed Option.

Table 8: Infeed Option Generation Plan

Year	Infeed Option	Additional Capacity (MW)	Type
2010			
2011			
2012			
2013			
2014	50 MW CT	50	Thermal
2015			
2016			
2017	Holyrood U1 Synchronous Condenser 900 MW Labrador-Island Link HVdc System	900	Hydroelectric
2018			
2019			
2020			
2021	Holyrood Decommissioning begins		
2022			
2023			
2024			
2025			
2026			
2027			
2028			
2029	Holyrood Decommissioning complete		
2030			
2031			
2032			
2033			
2034			
2035			
2036	23 MW Portland Creek	23	Hydroelectric
2037	170 MW CCCT (Greenfield)	170	Thermal
2038			
2039			
2040			
2041			
2042			
2043			
2044			
2045			
2046	50 MW CT (Greenfield)	50	Thermal
2047			
2048			
2049			
2050	50 MW CT (Greenfield)	50	Thermal
2051			
2052			
2053			
2054	50 MW CT (Greenfield)	50	Thermal
2055			

Year	Infeed Option	Additional Capacity	Type
2056			
2057			
2058	50 MW CT (Greenfield)	50	Thermal
2059			
2060			
2061			
2062			
2063	50 MW CT (Greenfield)	50	Thermal
2064			
2065			
2066	50 MW CT (Greenfield)	50	Thermal
2067			

4.1 Muskrat Falls Generating Station

The Muskrat Falls Generating Station feasibility studies, cost estimates, and schedule were examined by MHI's technical experts to determine if they were completed using practices and procedures normally followed in the development of hydroelectric sites. The arrangements proposed for Muskrat Falls Generating Station were also reviewed to determine whether there were any conditions that might preclude successful development of the scheme. The project has evolved from early conceptual studies in the 1960's to the present detailed arrangement. Key documents include the Feasibility Study³⁸ and its associated reference documents, which were completed in 1999. The arrangement of the project was subsequently updated in a series of studies, completed in 2010, that adapted the layout and design to suit changes in circumstances and the final development sequence for the Lower Churchill River.

MHI's review involved an examination of the key documents to assess the methodology adopted and information used to develop the final project arrangement. Clarifications were obtained from Nalcor during meetings held to discuss key aspects of the development. The review was not intended to be exhaustive but to be sufficient to ensure that the decisions and recommendations reached for development of the project were well founded on factual and appropriate information.

The proposed layout and design of the project appear to be well defined and consistent with good industry practices. Available studies have identified technical risks and appropriate risk mitigation strategies. Findings are as follows:

- Topographic and geotechnical conditions have been identified and provide a sound basis for construction.

³⁸ Exhibit 19, SNC-Agra, "Muskrat Falls Hydroelectric Development – Final Feasibility Study Volume 1", January 1999

- The installed capacity was selected based on the anticipated system cost for power and energy to optimize the project development.
- The general arrangement of the permanent works is a reasonable proposal for the optimum development in terms of cost and construction duration.
- Based on the information provided, the design and proposed construction sequence of the Muskrat Falls Generating Station are consistent with good engineering and construction practices, and should not pose unusual risks for construction or operation of the facilities.
- The powerhouse arrangement does not pose unusual risks or abnormal features. The selection of Kaplan units is a conventional choice for the head and discharge conditions. Several well qualified manufacturers are available to supply this equipment, which should allow for competitive pricing for equipment procurement.
- The transmission line and converter stations proposed are consistent with the requirements of Muskrat Falls Generating Station. There is no reason to expect any unusual risks or difficulties with the arrangement when the final design is prepared.
- Work has been scheduled for the construction of the facilities using conventional and proven methods. There is no reason to believe that the construction of the facilities proposed would result in unusual risks for cost escalation or time extensions.

A detailed project control schedule and cost estimate has been prepared for the Muskrat Falls development. The project control schedule was developed with an assumed contract strategy, taking into account the capability of contractors, weather conditions, access, and other constraints. The project control schedule is believed to be close to the optimum duration and to be a realistic basis for planning of the works.

Based on the information available, the overall construction duration is believed to be reasonable. The project schedule indicates that the Muskrat Falls development can be completed within a total of about 62 months³⁹, assuming release for construction and commencement of contract awards in January of year one.

The Nalcor DG2 Capital Cost Estimate for the Muskrat Falls development was prepared as a “bottom up” estimate that considered construction productivity and schedules along with the cost of materials, equipment, and labour required for construction. An overall review of the cost estimate was performed by MHI but a detailed review of the estimating procedures was not.

The cost estimate for the Muskrat Falls development has increased by 104% between 1998 and 2010 which can largely be explained by inflation and a change in scope. The change in scope is the addition of the 2 – 345 kV transmission lines from Muskrat Falls Generating Station to Churchill Falls Generating Station, associated switchyards, environmental costs and other items such as insurance. Despite the additional costs, MHI considers the cost estimate to be within the accuracy range of an AACE Class 4 estimate (+50%/-30%) which is representative of a feasibility level study.

³⁹ CE-15 Rev.1 (Public), SNC Lavalin, “Muskrat Falls Hydroelectric Project – MF1010 – Review of Variants”, March 2008, pg. 26

The cost estimate was prepared using an appropriate methodology that was applied in a comprehensive manner with relevant input data and assumptions. The scope of work identified for the estimate is in keeping with utility best practices. The resulting cost estimate appears to be consistent with the nature of the works proposed for construction, local conditions, and construction market conditions. The Base Cost Estimate for the works appears to be reasonable and should fairly represent the costs to be included in the Infeed Option. The approach adopted for project cost contingencies and escalation is also reasonable.

4.1.1 Muskrat Falls Generating Station Key Findings

The following key findings are noted from the Muskrat Falls development review:

- The proposed layout and design of the Muskrat Falls Generating Station appears to be well defined and consistent with good utility practices.
- The general arrangement of the permanent works is a reasonable proposal for the optimum development in terms of cost and construction duration.
- Based on the information provided, the design and construction of Muskrat Falls Generating Station is consistent with good engineering and construction practices, and should not pose any unusual risks for construction or operation of the facilities.
- The available studies have identified technical risks and appropriate risk mitigation strategies.
- The Muskrat Falls development cost estimate is within the accuracy range of an AACE Class 4 estimate even with the increased costs described above.

4.2 HVdc Converter Stations

The assessment of the technical work done by Nalcor on the HVdc converter stations, electrode lines, and associated switchyard equipment was undertaken by MHI as part of its technical review of the two options. It was carried out by HVdc experts on staff at MHI through meetings with Nalcor and reviews of a number of documents published by Nalcor relevant to the Gull Island development. Most project documentation on the Labrador-Island Link HVdc system was not available, such as the HVdc converter station single line diagram or a concept transition document, since the project definition changed in November 2010 with DG2. This lack of detailed information on the revised HVdc system hampered MHI's review.

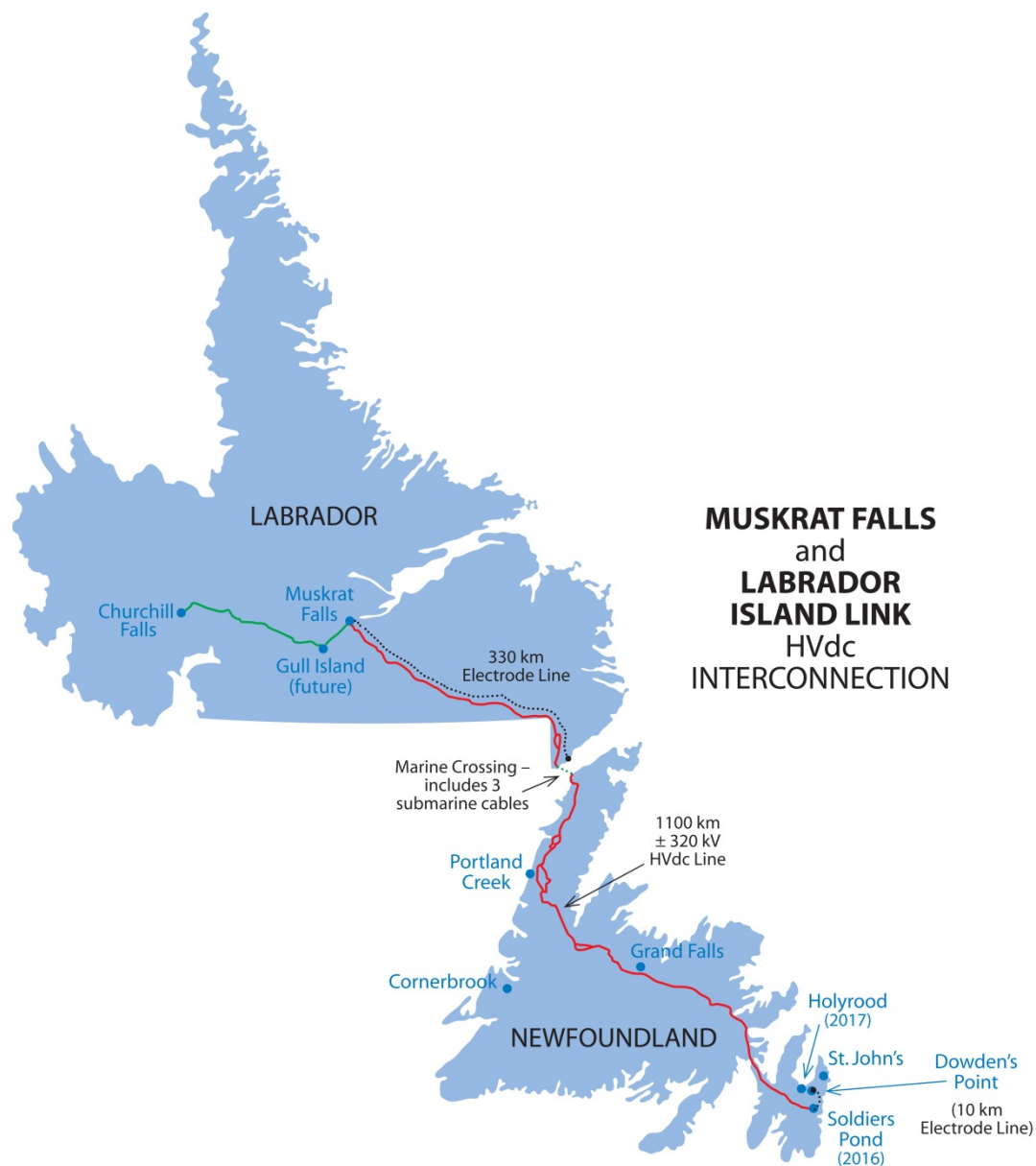


Figure 9: Muskrat Falls and Labrador Island Link HVdc Interconnection (locations are approximate)

The Labrador-Island Link HVdc System, as shown in Figure 9 above, is a 900 MW \pm 320 kV bipolar system for point-to-point HVdc transmission. It is comprised of a 900 MW converter station at Muskrat Falls (1350 MW with a 150% overload capability), associated ac and dc switchyards, and 330 km of transmission lines to the Strait of Belle Isle. At the Strait, there will be a transition station to a marine crossing with three fully rated submarine cables, one a spare, and appropriate cable protection systems crossing the strait and landing on the island. On the island shore, there will be another transition station connecting to switching equipment and the overhead HVdc transmission line to Soldiers Pond Converter Station near St. John's. At Soldiers Pond, there will be both ac and dc switchyards and ac and dc filters, plus 3 - 300 MVar (volt-ampere reactive) high inertia synchronous condensers providing the required reactive support to successfully deliver the power to the island.

Two shoreline electrodes are included in this system. The first electrode line from the Muskrat Falls converter station will follow the HVdc transmission line (or be mounted on the same tower) to an appropriate grounding point at the Strait of Belle Isle. The second electrode line will emanate from Soldiers Pond approximately 10 km to the electrode site near Dowden's Point in Conception Bay.

The DG2 cost estimates for the converter stations were reviewed, compared against industry benchmarks, and were found to be reasonable when costs identified for overload capabilities were included.⁴⁰

Nalcor's cost estimate for system upgrades includes three 300 MVar synchronous condensers plus the conversion of two generating units at Holyrood Thermal Generating Station as well as the addition of several high voltage breakers. MHI finds that these estimates are low but are within the bands of cost estimate variability and thus are reasonable as inputs to the DG2 screening process and CPW analysis.

MHI notes that there was no comprehensive HVdc system risk analysis review for operations and maintenance for the overall HVdc transmission system including converter station equipment, transmission lines, or converter station control, protection and communications. MHI recommends that this operational design risk analysis be completed in conjunction with the development of the HVdc converter station specification so that any additional requirements may be included.

4.2.1 HVdc Converter Stations Key Findings

Key findings from MHI's review of the HVdc converter stations are as follows:

- The design parameters available to date for review are reasonable for the intended application, which has a basic requirement to transmit 900 MW over 1100 km of transmission line and inject this power into the island electrical system at Soldiers Pond with appropriate voltage and frequency control.
- The choice of line commutated converter (LCC) HVdc technology is mature and robust for the Labrador-Island Link HVdc transmission system. Newer technology exists with the recent

⁴⁰ CE-51, Nalcor, Technical Note: "Muskrat Falls Generation Facility and Labrador – Island Transmission Link, Overview of Decision Gate 2 Capital Cost and Schedules", August 2011

introduction of voltage source converter (VSC) systems. In a response to an RFI, Nalcor identified that VSC options will be considered if there are technical and financial advantages to do so. It is important to note that VSC systems of the size and length of the Labrador-Island HVdc system have not yet been built and operated anywhere in the world.

- The total cost estimate for the HVdc converter stations and electrodes based on an AACE Class 4 estimate are reasonable for DG2 purposes. The costs for the synchronous condensers are low but are still within the range of an AACE Class 4 estimate.

4.3 HVdc Transmission Lines

MHI has reviewed the design information provided by Nalcor for the Infeed Option as it pertains to risk and reliability. The appropriate design criteria for the proposed Labrador-Island Link HVdc transmission line is the “Design Criteria of Overhead Transmission Lines” code (International Standard CEI/IEC 60826:2003) with Canadian deviations in CSA Standard CAN/CSA-C22.3 No. 60826:06.

4.3.1 Reliability Based Transmission Line Design

MHI finds that Nalcor’s decision to adopt the IEC Standard and CSA Code for the design reliability criteria is appropriate. Review of the exhibits and reports provided by Nalcor indicate that much effort has gone into gathering historical weather and infrastructure performance data. This information is essential when designing with reliability based methods for new transmission lines. Reliability based design uses a statistical approach based on probable return periods.

Nalcor’s Exhibit 106, page 8, has introduced a suitable definition of a return period from the IEC standard used to characterize transmission line reliability:

“Simply put, the return period is a statistical average of occurrence of a climatic (weather load) event that has a defined intensity (ice and/or wind load) and is often described in terms of years. For example, a one in 50 year (1:50) event will occur on average once every 50 years.”

Exhibit 106 describes the adoption of the “Design Criteria of Overhead Transmission Lines” CEI/IEC 60826:2003 with Canadian deviations in CAN/CSA-C22.3 No. 60826:06 as the National Standard of Canada. The document also describes the process followed by Nalcor in its decision to use reliability based design as outlined in this same standard.

Exhibit 106 refers to the selection of reliability levels as described in Section A.1.2.5 page 125 of the 60826 IEC: 2003 document which is presented below in full.

A.1.2.5 Selection of Reliability Levels

Transmission lines are typically designed for different reliability levels (or classes) depending on local conditions, requirements and the line duties within a supply network. Designers can choose their reliability levels either by calibration with existing lines that have had a long history of satisfactory performance or by optimization methods found in technical literature.

In all cases, lines should at least meet the requirements of a reliability level characterized by a return period of loads of 50 years (level 1). An increase in reliability above this level could be justified for more important lines of the network as indicated by the following guidelines:

It is suggested to use a reliability level characterized by return periods of 150 years for lines above 230 kV. The same is suggested for lines below 230 kV which constitute the principal or perhaps the only source of supply to a particular electric load (level 2).

Finally, it is suggested to use a reliability level characterized by return periods of 500 years for lines, mainly above 230 kV which constitute the principal or perhaps the only source of supply to a particular electric load. Their failure would have serious consequences to the power supply.

The applications of the reliability for overhead lines, including corresponding voltage levels, may be set differently in various countries depending on the structure of the grid and the consequences of line failures. The impacts on other infrastructure installations such as railroads and motorways should be considered as well in the establishment of reliability criteria.

When establishing national and regional standards or specifications, decisions on the reliability level should be made taking into consideration also the experience with existing lines.

Nalcor states in Exhibit 106 that, since the existing 230 kV ac system is designed to a lesser reliability level, there is no justification to increase the reliability level of the HVdc link as the ac transmission system would fail for an event greater than the 1:50 year return period.

Considering the directions given in the IEC Standard, the voltage level of the Labrador-Island Link HVdc transmission line, the importance of this HVdc transmission line, and the local historical data gathered by Nalcor during the investigation of the Avalon Peninsula upgrade project, at a minimum the ± 320 kV HVdc line should be designed to a return period of 1:150 years when an alternate supply is available. Nalcor should also give consideration to an even higher reliability level return period in the remote alpine regions⁴¹. MHI recommends that the HVdc transmission line be designed to a 1:500-year return period for the Island power system without an alternate supply. MHI considers this a major issue and recommends that Nalcor adhere to these criteria laid out in the IEC Standard for the HVdc transmission line design. Design for less than 1:150 year return period is contrary to best practices carried out by utilities in Canada, and does not reflect current industry practices which follow IEC 60826:2003.

No design optimization plan has been provided for the review or justification of the reduced transmission line reliability.

⁴¹ Exhibit 97, Page 8. Alpine regions are defined as Southeastern portion of Labrador, two areas in the Long Range Mountains, and one small section in central Newfoundland.

Nalcor has estimated that the additional cost to build the transmission line to a 1:150 year return period is \$150 million⁴². MHI, based on prior estimates for similar projects, confirms that the estimated additional cost of a \$150 million dollars for moving from a 1:50 year return period to a 1:150 year return period is reasonable.

4.3.2 Transmission Design Review and Route Selection

As stated in the response to MHI-Nalcor-71, “The design details requested are not available as these are the subject of detailed design efforts by SNC Lavalin and will not be completed before 2012”. MHI cannot provide comment on the overall tower design as none of the tower loading conditions were provided (i.e., construction loads, maintenance loads, torsional loads, and broken conductor scenarios), and only a few of the climatic loads were given. Further, MHI is unable to comment on the appropriateness of the route selection or risk analysis for the transmission line.

4.3.3 Cost Evaluation of Overhead Transmission Line Estimate

MHI has reviewed the cost estimate for the HVdc overland transmission line supplied in the confidential exhibit “Overview of Decision Gate 2 Capital Costs”⁴³. The DG2 capital cost value falls inside the typical range of capital construction estimates for this type and length of transmission line. Nalcor’s estimate is at the low end of the range.

4.3.4 Conclusions

Reliability based design is an appropriate method for the Infeed Option transmission line since there has been extensive meteorological analysis conducted. To support the design process, historical strength data for existing transmission lines were available from the work completed as part of the transmission line upgrade on the Avalon Peninsula.⁴⁴

Considering the directions given in the IEC Standard, the voltage level of the Labrador-Island Link HVdc transmission line, the importance of this line, and the local historical data gathered by Nalcor, at a minimum the ± 320 kV HVdc line should be designed to a return period of 1:150-year when an alternate supply is available. For this scenario consideration should also be given to an even higher reliability return period in the alpine regions⁴⁵ which are impacted by significantly greater ice and wind loads. The Labrador-Island HVdc line should be designed to a 1:500 year return period when there is no alternate supply.

Nalcor’s exhibit 106 refers to the adoption of a 1:50 year return period for new 230 kV transmission line design and states that a 1:50 year return period is justifiable for the ± 320 kV HVdc line. The response to

⁴² Response to RFI PUB-Nalcor-15

⁴³ CE-51, Nalcor, “Technical Note: Muskrat Falls Project:–Muskrat Falls Generation Facility and Labrador – Island Transmission Link Overview of Decision Gate 2 Capital Cost and Schedule Estimates”, August 2011.

⁴⁴ Exhibit 6, System Planning Department, Newfoundland and Labrador Hydro, “Technical Note: Labrador-Island HVdc link and Island Interconnected System Reliability,” October 2011.

⁴⁵ Exhibit 97, Page 8. Alpine regions as defined as Southeastern portion of Labrador, two areas in the Long Range Mountains, and one small section in central Newfoundland.

RFI PUB-Nalcor-13 also documents the 1:50 year return period as suitable for the Labrador-Island Link HVdc transmission line when considered together with the addition of the Maritime Link. As specified by the IEC/CSA Standard, there is a requirement to design to a 1:150 or 1:500 year return period depending on the criticality of the transmission line. Nalcor states that since the existing 230 kV ac system is designed to a lesser reliability level, there is no justification to increase the reliability level of the HVdc link as the ac transmission system would fail for an event greater than 1:50 year return period. MHI considers this to be a major issue and it is contrary to best practices carried out by utilities in Canada for transmission line design, and does not reflect current industry practices which follow IEC60826:2003.

4.3.5 HVdc Transmission Lines Key Findings

The key findings from the HVdc transmission line review are as follows:

- Nalcor has selected a 1:50-year reliability return period (basis for design loading criteria) for the HVdc transmission line, which is inconsistent with the recommended 1:500-year reliability return period outlined in the International Standard CEI/IEC 60826:2003 with Canadian deviations in CSA Standard CAN/CSA-C22.3 No. 60826:06, for this class of transmission line without an alternate supply. In the case where an alternate supply is available, the 1:150-year reliability return period is acceptable. In this latter scenario, Nalcor should also give consideration to an even higher reliability return period in the remote alpine regions⁴⁶. MHI considers this a major issue and strongly recommends that Nalcor adhere to these criteria for the HVdc transmission line design. The additional cost to build the line to a 1:150 year return period is approximately \$150 million.
- The capital cost estimate of the transmission line at DG2 is reasonable, but at the low end of the range for this type of construction utilizing industry benchmark costs as a comparison. A design based on a 150-year return period could be accommodated within the variability of an AACE Class 4 estimate at this stage of development for the entire Labrador-Island Link HVdc project.

4.4 Strait of Belle Isle Marine Crossing

The Strait of Belle Isle (SOBI) marine crossing is a critical component of the Labrador-Island Link HVdc transmission line and will consist of three ± 350 kV submarine cables in a 36 km long corridor across the Strait. The cables will have a shore approach with a landing site in the area of L'Anse Amour beach in Forteau Bay on the Labrador side, and in the area of Mistaken Cove on the Newfoundland side.

⁴⁶ Exhibit 97, Page 8. Alpine regions are defined as Southeastern portion of Labrador, two areas in the Long Range Mountains, and one small section in central Newfoundland.

MHI engaged CESI, an external consultant specializing in submarine cable crossings, to evaluate the studies and reports conducted by Nalcor's consultants of the proposed Strait of Belle Isle marine crossing. CESI's qualifications are described in Volume 2, Section 13.

In reviewing the marine crossing, MHI met with Nalcor's staff and their consultant C-CORE. A number of documents were also reviewed including:

- several feasibility studies
- risk reports
- cost estimates
- specifications
- design concept documents
- confidential exhibits CE-40 through 44
- Exhibit 33: Summary of Ocean Current Statistics for the Cable Crossing SOBI
- Exhibit 34: Review of Fishing Equipment – Strait of Belle Isle
- Exhibit 35: Nalcor's SOBI Iceberg Cable Risk
- Exhibit 37: SOBI Decision Recommendation Oct 12, 2010
- and CE-55 Request for Proposal (RFP) No. LC-SB-003 "Strait of Belle Isle Submarine Cable Design, Supply, and Install."

4.4.1 Cable Specifications

The conductor has been specified as ± 350 kV single core aluminium or copper cable with mass impregnated (MI) paper insulation. The cables will be armoured to match the required pulling tension strength and provide for cable protection when building rock berms on the seafloor. The nominal cable voltage rating will be ± 320 kV with a nominal current carrying capability of 1286 A (450 MW), continuous rating of 1929 A at 1.5 pu, and a transient rating of 2572 A (2 pu for 10 minutes)⁴⁷. These ratings match the HVdc converter station capabilities.

The selection of the core area is dependent on losses, the thermal properties of the cable, and the surrounding environment. The final cable size selection will be based on a detailed engineering analysis performed by the supplier.

4.4.2 Cable Route

The Strait of Belle Isle marine crossing is extremely complex and poses numerous challenges for cable installation and protection. Challenges include sea currents, icebergs, pack ice, tidal forces, rock placement, varying water depths, fishing activities and vessel traffic.

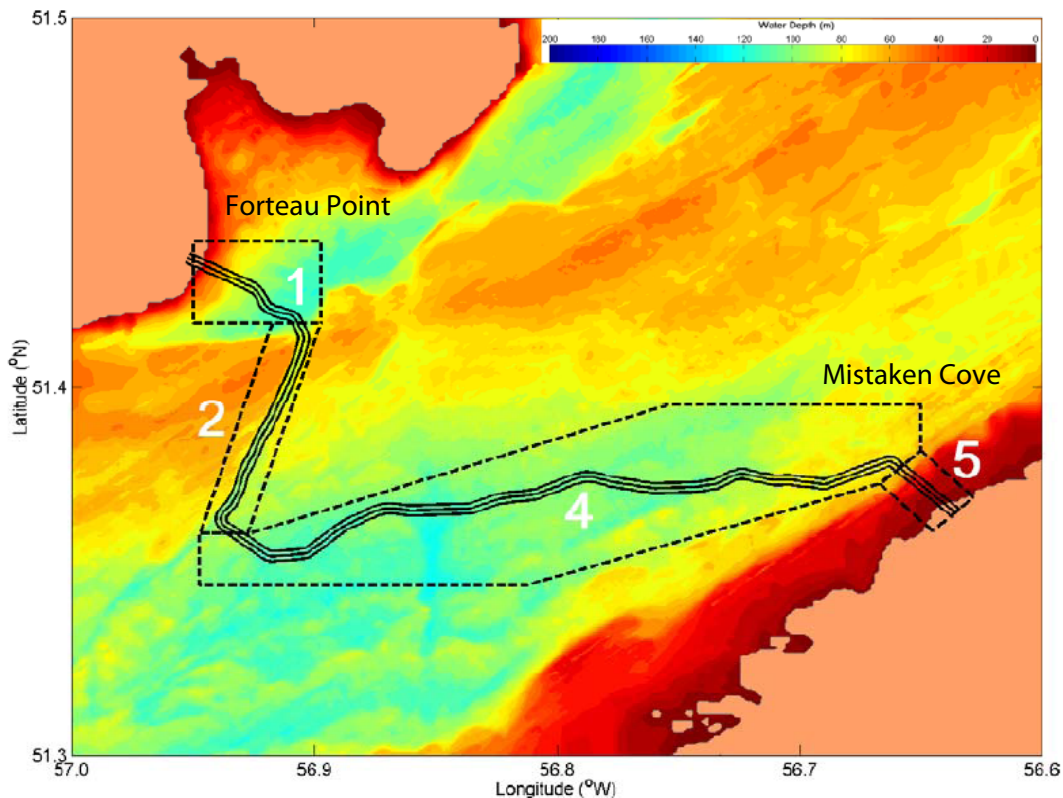
The cable corridor is shown below in Figure 10. This corridor takes into account the relevant landfall and possible protection methods. The estimated length is approximately 36 km, with roughly 32 km on the sea floor. The route is depicted within a 500-m-wide corridor with a 1500-m diameter circular

⁴⁷ CE-55 Rev 1 (Public), Nalcor, "Request for Proposal (RFP) No. LC-SB-003 Strait of Belle Isle Cable Design, Supply, and Install", August 2011

sea floor piercing target zone for horizontal directional drilling. Zone 3 is not shown but has been known as the Eastern Corridor and was not used due to the depth of water and potential for iceberg scouring.

MHI generally agrees with Nalcor's selection of the preferred alternative which included horizontal directional drilling as a means of shore approach for the cable and laying the cable on the seabed with a rock berm protection scheme. Nalcor's recommended design has been carefully formulated based on the synthesis of the conclusions reached in the various study documents.

Figure 10: Strait of Belle Isle Marine Crossing



4.4.3 Iceberg Risks

C-CORE and Fugro Geo Surveys conducted a review of the Strait of Belle Isle crossing as this area is frequented by icebergs which pose a hazard to any cables either placed on or trenched into the seabed. Their report described the application of a model to assess iceberg risk to cables laid on the seabed in the Strait of Belle Isle.

The iceberg scour data was the first systematic assessment of the scour regime in this area. The observed spatial distribution of iceberg scours was unexpected with the majority of scours occurring in deeper water. However, these scours could have taken place in previous glacial periods. This cannot be positively confirmed and as such there is a risk generally in the 70 – 75 metre water depth range. The iceberg risk analysis used a state of the art Monte Carlo based iceberg contact simulation that models the distribution of iceberg groundings and incidents where iceberg keels are close enough to contact a cable on the seabed. Icebergs have been observed to roll and this was considered in the simulations as an increased roll rate increases the risk to scouring. The separation distance between cables was compared to observed scour length distributions and it was noted that the probability of contacting multiple cables is reduced with increased separation distance. The software used to model iceberg contact risks was developed by C-CORE and verified through other research on the Grand Banks, Conception Bay, and with field observations in the Strait of Belle Isle.

C-CORE has concluded that the iceberg grounding risk to the cables in the Strait of Belle Isle is a 1:1000 year event at a cable depth greater than 70 meters, and an iceberg roll rate of one every ten days. Increasing the roll rate to one roll every day increases the risk to approximately a 1:400 year event at the same depth.

4.4.4 Marine Crossing Costs

The total base cost estimate for the marine crossing in DG2 was reviewed by MHI. The cost estimate prepared by CESI has confirmed Nalcor's cost estimate is within the range of an AACE Class 4 cost estimate.

4.4.5 Strait of Belle Isle Key Findings

MHI's key findings on the Strait of Belle Isle marine crossing are as follows:

- The selection of a ± 350 kV mass impregnated cable is an appropriate technology selection for the application of an HVdc marine crossing operating at ± 320 kV. Other technologies, such as cables with cross-linked polyethylene insulation, have been type tested for this application at ± 320 kV but none have been used at this voltage level on a marine HVdc project in the world today.
- Nalcor's total base cost estimate for the marine crossing at DG2 was reviewed by CESI, an independent engineering firm experienced in HVdc marine crossings. Nalcor's estimate is within the range of an AACE Class 4 cost estimate.
- The iceberg risks are perceived to be significant; however, the application of horizontal directional drilling for shore landings, years of iceberg observations and research performed by C-CORE (a local consulting firm) on the Grand Banks for the various oil projects, and careful route selection across the Strait of Belle Isle have quantified the risks to be less than one iceberg strike in 1000 years. This risk is further mitigated with rock berms, largely for fishing equipment and anchor protection, and a spare cable with separation distance between them of 50 to 150 metres. The research performed by C-CORE found that the risk of a multiple cable contact by icebergs was reduced with greater separation of the cables. Additional research, monitoring of iceberg roll rates, and bathymetric surveys of earlier iceberg scours should be done to provide a level of validation to further tune the iceberg strike risk model.

- Application of a spare cable with as much separation as practical is a prudent design feature of the Strait of Belle Isle marine crossing considering the potential difficulties of bringing in repair equipment at certain times of the year.

5 Technical Review – Isolated Island Option

The Isolated Island Option is largely a thermal generation plan, with the addition of seven CCCT units of 170 MW each and nine CT units of 50 MW each, totalling 1,640 MW of thermal, three new hydro plants totalling 77 MW, and one new wind farm of 25 MW, which when combined total 1,742 MW of new generation. Over the course of the review period, the two existing wind plants are replaced in 2028 and 2048; and the new wind plant is replaced twice in 2034 and 2054. All generation associated with the Isolated Island Option is contained on the island, with no interconnections to the mainland.

Table 9 describes the timing, size, and type of new generation sources added to the island as well as required upgrades and replacements in the Isolated Island Option.

Table 9: Isolated Island Option Generation Expansion Plan

Year	Isolated Island Option	Additional Capacity (MW)	Type
2010			
2011			
2012			
2013			
2014	25 MW Wind farm	25	Wind
2015	Holyrood ESP and Scrubbers		Thermal
	Island Pond	36	Hydroelectric
2016	Holyrood Life Extension (5-yr \$20 M /yr)		Thermal
2017	Holyrood Low Nox Burners		Thermal
2018	Portland Creek	23	Hydroelectric
2019	Holyrood Upgrades		Thermal
2020	Round Pond	18	Hydroelectric
2021			
2022	170 MW CCCT (Greenfield)	170	Thermal
2023			
2024	50 MW CT (Greenfield)	50	Thermal
	Holyrood Upgrades		Thermal
2025			
2026			
2027	50 MW CT (Greenfield)	50	Thermal
2028	Replace 2 existing wind farms (~54 MW)		Wind
2029	Holyrood Upgrades		Thermal
2030	50 MW CT (Greenfield)	50	Thermal
2031			
2032			
2033	Holyrood U1 and U2 Replacement - 170 MW CCCT		Thermal
2034	Replace 2014 wind farm (~25 MW)		Wind
2035			
2036	Holyrood U3 Replacement - 170 MW CCCT		Thermal
2037			
2038			
2039			
2040			
2041			
2042	50 MW CT (Greenfield)	50	Thermal
2043			
2044			
2045			

Year	Isolated Island Option	Additional	Type
2046	50 MW CT (Greenfield)	50	Thermal
2047			
2048	Replace 2 existing wind farms (~54 MW)		Wind
2049	50 MW CT (Greenfield)	50	Thermal
2050	170 MW CCCT (Greenfield)	170	Thermal
2051			
2052	170 MW CCCT (Greenfield)	170	Thermal
2053			
2054	Replace 3 rd Wind farm (~25 MW)		Wind
2055			
2056	170 MW CCCT (Greenfield)	170	Thermal
2057			
2058			
2059			
2060			
2061			
2062			
2063	50 MW CT (Greenfield) - 2 Units	100	Thermal
	170 MW CCCT (Greenfield)	170	Thermal
2064	50 MW CT (Greenfield)	50	Thermal
2065			
2066	170 MW CCCT (Greenfield)	170	Thermal
2067	170 MW CCCT (Greenfield)	170	Thermal

5.1 Thermal Generating Plants

Future utilization of the Holyrood Thermal Generating Station is very different for each of the two options. Also, both options make extensive use of combustion turbines and combined cycle combustion turbines as part of their generating expansion plan. Reviews of the various assessments of the thermal assets are summarized in Section 6 of this report, and covered in greater detail in Volume 2 – Section 10.

5.2 Small Hydroelectric Plants

The Isolated Island Option requires the addition of three small hydroelectric generation projects at Round Pond, Portland Creek, and Island Pond. Portland Creek is also required in the Infeed Option, but not until 2036.

Table 10: Small Hydroelectric Plant Summary

Plant	Capacity (MW)	Firm Energy (GWh)	Base Estimate (2010\$ M)
Round Pond	18	108	\$142
Portland Creek	23	99	\$90
Island Pond	36	172	\$166
Total	77		

Each of the plants has been the subject of one or more studies, including those that are presented as feasibility level studies. The studies were conducted by consulting engineering firms with extensive experience in the engineering of hydroelectric projects. Nalcor relied on the findings of these studies for inputs to the Strategist model it used to produce CPW analyses for the Isolated Island and Infeed Options.

The basis for Nalcor's capacity, capital cost, schedule, and availability inputs to the Strategist tool for CPW analyses was reviewed for reasonableness. The reviews of the three plants generally focused on the most recent and advanced studies made available by Nalcor. The required level of review was judged in the context of the relatively small scale of the three plants relative to the overall expenditures and the large difference in CPW between the Isolated Island and Infeed Options.

For additional information on the review of the small hydroelectric generating stations at Island Pond, Round Pond, and Portland Creek, please refer to Volume 2 – Section 9.

5.2.1 Small Hydroelectric Plant Key Findings

The following key findings from the small hydroelectric plant reviews are as follows:

- A review of the capital cost estimates for the three small hydroelectric plants indicated that the level of engineering and investigations were consistent with a feasibility study. Considering the age of some of the studies, the review also indicated that the development schedules and cost estimates used as inputs to Strategist for the three projects were optimistic in light of current, more stringent environmental processes.
- It is expected that resolution of these uncertainties would generally result in increases rather than decreases in the CPW of the three projects. However, the magnitude of any changes would not be expected to significantly alter the difference in CPW between the Isolated Island and Infeed Options. It is therefore concluded that Nalcor's Strategist inputs for the capacity, direct capital costs, schedule, and outage rates for the three small hydroelectric projects provide a reasonable basis for comparing the two expansion options when considered against the significantly larger expenditure for fuel in the Isolated Island Option.

5.3 Wind Farms

In the Isolated Island Option, a new 25 MW wind farm is proposed and scheduled for in-service in 2014. This is in addition to the 27 MW wind farms already in operation at St. Lawrence and Fermeuse. The latter two wind farms have a 20-year Power Purchase Agreement (PPA) with NLH. Once the contract period ends, there is a build-own-operate-transfer clause that allows transfer of ownership of the wind farm assets to NLH at no cost⁴⁸. For the CPW calculation, it is assumed that the wind farms have a 20-year operating life⁴⁹, and that after this period, the entire wind farm would be replaced by NLH. The replacement cost of each of the wind farms was factored into the CPW calculation.

⁴⁸ Exhibit 6a, Nalcor, "PPA Listing and Rates".

⁴⁹ Exhibit 7, Nalcor, "Service Life-Retirements"

The review of the wind farms included the following objectives:

- Assess related planning and cost estimates for the wind farm and verify the estimates are reasonable.
- Examine related studies or assumptions such as wind survey, annual capacity factor and assessment of allowable non-dispatchable wind capacity in the island grid.

The review was conducted in sufficient detail to ensure that the wind assessment had been performed with due diligence.

5.3.1 Cost Estimates and Capacity Factors

The existing price structure used in the evaluation for a new wind farm in 2014 is based on NLH's current wind PPA structure as outlined in Exhibit 25⁵⁰. Capital costs for the replacement of wind farms is based on the 2007 Ontario Power Authority Integrated Power System plan. Operations and maintenance costs for these new wind farms are based on information from NLH recent requests for proposals. MHI considers that the estimated capital and operating costs used by Nalcor in the CPW analysis are representative of projects of this type and are appropriate for use at DG2.

An annual capacity factor of 40% is assumed for the 25 MW wind farm, based on the average capacity factor between the two existing wind farms at Fermeuse (44.3% capacity factor) and St. Lawrence (35.7% capacity factor). No specific site and wind survey data has been collected for the proposed new wind farm to validate the 40% annual capacity factor. According to Nalcor, the proposed site for the new 25 MW wind farm would be selected through a wind RFP process⁵¹. Nalcor added that from previous 2005 and 2006 wind RFPs, submissions from other proponents (excluding Fermeuse and St. Lawrence wind proponents) indicated expected net annual capacity factors ranging from 35%-43%. In MHI's opinion, a 40% annual capacity factor appears to be a reasonable assumption for a planning estimate.

5.3.2 Assessment of Non-Dispatchable Capacity

From the analysis performed in 2004, an upper limit of 80 MW was recommended by Nalcor for wind generation on the Isolated Island system for the following reasons:

1. Water management: Additional wind generation beyond 80 MW would result in less load being supplied by hydroelectric generation. This would result in wasteful spillage of water from reservoirs. For example, by adding 20 MW to the upper limit of 80 MW, the annual water spill energy equivalent would approximately double from the existing 9 GWh to 19 GWh.
2. Transmission grid security: Non-dispatchable generation could displace the demand for hydroelectric generation and cause the transmission network to be lightly loaded in certain

⁵⁰ Exhibit 25, Nalcor, "Board Letter July 12th 2011: Q5: A report on the information and data collected for wind farms", July 2011.

⁵¹ Response to RFI MHI-Nalcor-87

areas, resulting in an overvoltage condition. A small disruption to the system could then cause widespread system disturbances.

3. Regional transmission voltage: The study notes a possible overvoltage condition due to limited voltage control provided by wind generation installations.

These reasons, identified in the 2004 study, still apply today as the power system has not substantially changed⁵².

5.3.3 Wind Farms Key Finding

The key finding from the wind farms review is as follows:

- The capacity factor of 40% used by Nalcor is reasonable for a planning study. The estimated capital and operating costs used in the analysis are appropriate. Nalcor's assessment of an 80 MW limit for wind generation under the Isolated Island Option appears reasonable. Additional wind power could be installed beginning in the 2025 timeframe as the system capacity grows.

⁵² Response to RFI MHI-Nalcor-89

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6 Thermal Generating Stations

6.1 Introduction

The Island of Newfoundland relies heavily on existing thermal power sources to supply energy (33% in 2010). The Holyrood Thermal Generating Station (HTGS) and two CTs (110 MW) are currently used by Nalcor to satisfy load requirements. In both Options, thermal generation will be used to supplement the energy and capacity requirement to meet the reliability criteria.

The Infeed Option includes the addition of 520 MW of thermal generation using combustion turbines. This generation plan includes:

- Synchronous condenser conversion projects at HTGS for units 1 and 2 plus some life extension work to keep the plant running as synchronous condensers (2041).
- 7 - 50 MW new Combustion Turbines (CT).
- 1 - 170 MW new Combined Cycle Combustion Turbine (CCCT).

The Isolated Island Option is largely a thermal generation plan with the addition of 1,640 MW of CTs and CCCTs. The Isolated Island Option generation plan includes:

- Installation of environmental emissions controls at HTGS (electrostatic precipitators, scrubbers and low NO_x burners).
- Life extension projects at Holyrood with eventual replacement of the units in 2033 and 2036 with 3 – 170 MW CCCTs.
- 9 - 50 MW new CTs.
- 7 - 170 MW new CCCTs.

The Infeed Option contains significantly less thermal generation than the Isolated Island Option. By 2067 there still will be some thermal generation emissions as the HTGS is decommissioned and 520 MW of CCCTs and CTs are added primarily as peaking units. The Isolated Island Option, with 1640 MW of new thermal and 510 MW of replacement thermal for HTGS, will emit significantly more greenhouse gases (GHG).

Exhibit 16, page 27, states that “...the current Provincial Government 25,000 tons per year limitation on SO_x emissions from the HTGS, have traditionally been included in generation planning studies.”⁵³ The 25,000 tonnes per year limitation on SO_x emissions from HTGS commenced in 1991. To date, the only year that annual emissions exceeded 25,000 tonnes was in 1989, when the SO_x emissions at HTGS totaled 25,900 tonnes⁵⁴. However, if 0.7% sulphur content fuel continues to be used at the facility, this target will not be exceeded in the future even when the load factor is increased.

⁵³ Exhibit 16, Nalcor, “Generation Planning Issues 2010 July Update”, July 2010

⁵⁴ Response to RFI PUB-Nalcor-17

Even though Nalcor has projected a capital cost of \$603 million for an environmental equipment upgrade, this investment will not reduce GHG emissions, which are expected to increase as the load factor of the plant increases. Should the GHG emission standard change through public policy to a lower target, there is the risk that an oil fired facility such as HTGS may not be able to operate in the long term. The proposed pollution control upgrades for HTGS under the Isolated Island Option meet the Newfoundland and Labrador Energy Plan's commitment to address environmental concerns at HTGS.

6.2 Holyrood Thermal Generating Station

HTGS located on the south shore of Conception Bay, consists of three heavy fuel oil boilers for a combined net generating capacity of 466 MW. HTGS currently supplies approximately one third (up to 2,996 GWh annually) of the island's existing firm energy. The plant normally operates all three units during the highest customer demand periods of December through to March. HTGS production and operating factor can vary from year to year depending on the amount of hydraulic energy production, weather conditions, and industrial load requirements. HTGS Unit 3 generator is capable of synchronous condenser operation to assist in voltage control during the off peak season. HTGS Units 1 and 2 are over 40 years old and Unit 3 has exceeded 30 years of service.

As HTGS uses heavy fuel oil, it is a significant source of pollution emissions within Newfoundland and the amount of emissions is proportional to energy production. Nalcor has stated that environmental stewardship is one of its guiding principles as documented within the provincial energy plan (Focusing Our Energy: Newfoundland and Labrador Energy Plan).⁵⁵ HTGS does not currently employ environmental equipment to control SO_x or particulate emissions.

MHI's thermal specialists performed an assessment of the various options for HTGS and the planned CTs and CCCTs in meetings with Nalcor, a review of available documentation, and responses to RFIs.

6.3 Thermal Generation Options

Nalcor has investigated various options to upgrade or replace HTGS, which is approaching its end of service life. The initial screening study performed by AMEC⁵⁶ concluded that the HTGS life could be extended if capital investments were made for the refurbishment or replacement of critical plant equipment. Studies completed by Stantec⁵⁷ and Alstom⁵⁸ were made regarding the addition of pollution control equipment at HGTS in order to comply with the Government's directive on the addition of such equipment, if continued operation of the HTGS is required. Additional studies also concluded that CTs and CCCTs burning light fuel oil could be utilized on the island.

⁵⁵ Government of Newfoundland and Labrador, "Focusing Our Energy: Newfoundland and Labrador Energy Plan," 2007

⁵⁶ Exhibit 44, AMEC, "Newfoundland and Labrador Hydro, Holyrood Thermal Generating Station Condition Assessment & Life Extension Study", January 2011

⁵⁷ Exhibit 5-L-I, Stantec, "Precipitator and Scrubber Installation Study Holyrood Thermal Generating Station", November 2008

⁵⁸ Exhibit 68, SGE Acres, "Air Emission Controls Assessment – Holyrood Thermal Generating Station Final Report", February 2004

6.3.1 Isolated Island Option Thermal Plan

The Isolated Island Option expansion plan includes the continued operation of HTGS with the addition of pollution abatement equipment and life extension and upgrade investments to allow the operation of the plant to 2033 (units 1 & 2) and 2036 (unit 3). After this date the HTGS would be replaced with CCCT technology. The schedule and costs for the thermal capital works and retirements are outlined in Table 11.

Table 11: Isolated Island Option Thermal Plan

Isolated Island Option Thermal Plan			
Thermal Related Installations, Life Extensions & Retirements			
Year	Description	Costs (millions)	Retirements
2015	Holyrood ESP & Scrubbers	\$582	
2016	Holyrood Life Extension (5-yr \$20 M /yr)	\$100	
2017	Holyrood Low NOx Burners	\$20	
2019	Holyrood Upgrades	\$121	
2022	170 MW CCCT (Greenfield)	\$282	Hardwoods CT (50MW)
2024	50 MW CT (Greenfield) Holyrood Upgrades	\$91 \$9	Stephenville CT (50MW)
2027	54 MW CT (Greenfield)	\$97	
2029	Holyrood Upgrades	\$4	
2030	50 MW CT (Greenfield)	\$103	
2033	Holyrood U1 Replacement - 170 MW CCCT Holyrood U2 Replacement - 170 MW CCCT	\$346 \$447	Holyrood Unit 1 (161.5 MW) Holyrood Unit 2 (161.5 MW)
2036	Holyrood U3 Replacement - 170 MW CCCT	\$492	Holyrood Unit 3 (142.5 MW)
2042	50 MW CT (Greenfield)	\$130	
2046	50 MW CT (Greenfield)	\$141	
2049	50 MW CT (Greenfield)	\$149	50 MW CT
2050	170 MW CCCT (Greenfield)	\$477	
2052	170 MW CCCT (Greenfield)	\$665	50 MW CT & 170 MW CCCT
2056	170 MW CCCT (Greenfield)	\$534	
2063	50 MW CT (Greenfield) - 2 Units 170 MW CCCT (Greenfield)	\$395 \$818	2 x 170 MW CCCT
2064	50 MW CT (Greenfield)	\$201	
2066	170 MW CCCT (Greenfield)	\$645	170 MW CT
2067	170 MW CCCT (Greenfield)	\$882	50 MW CT

6.3.2 Infeed Option Thermal Plan

Under the Infeed Island alternative the HTGS would be required to operate as is until at least 2017 then maintained in standby mode for power generation from 2017 to 2021. HTGS would primarily be operated in synchronous condenser mode from 2017 onwards. The schedule and costs for the thermal capital works and retirements for the Infeed Option are outlined in Table 12.

Table 12: Infeed Option Thermal Plan

Infeed Option Thermal Plan			
Thermal Related Installations, Life Extensions & Retirements			
Year	Description	Costs (millions)	Retirements
2014	50 MW CT	\$75	
2017	Holyrood Units 1 & 2 Synchronous Condenser Conversion	\$3	
2021	Holyrood decommissioning begins	\$15	Holyrood Unit 1 (161.5 MW) Holyrood Unit 2 (161.5 MW) Holyrood Unit 3 (142.5 MW)
2022			Hardwoods CT (50 MW)
2024			Stephenville CT (50 MW)
2025			
2029	Holyrood decommissioning complete	\$12	
2037	170 MW CCCT (Greenfield)	\$373	
2039			50 MW CT
2041	Holyrood Synchronous Condensers decommissioned		Units 1, 2, and 3.
2046	50 MW CT (Greenfield)	\$141	
2050	50 MW CT (Greenfield)	\$152	
2054	50 MW CT (Greenfield)	\$165	
2058	50 MW CT (Greenfield)	\$179	
2063	50 MW CT (Greenfield)	\$197	
2066	50 MW CT (Greenfield)	\$209	
2067			170 MW CCCT

6.4 Holyrood Thermal Generating Station Pollution Control Equipment Upgrades

With the Isolated Island Option, Units 1 and 2 of the HTGS would continue operating until 2033, and Unit 3 until 2036, when the station would be replaced. The station would require various upgrades to continue operating as a generating plant, where most of these upgrades involve the addition of pollution control equipment including electrostatic precipitators, scrubbers, and low NOx burners required to meet Government's directive.

Nalcor has committed to install equipment to control SOx and particulates at HTGS if the Lower Churchill Project does not proceed⁵⁹. This decision complies with the Newfoundland and Labrador Energy Plan by addressing environmental concerns at HTGS. HTGS currently meets SOx emission limits specified in the Certificate of Approval - AA06-025458B, and has only exceeded these limits once during heavy operation.

⁵⁹ Exhibit 68, SGE Acres Limited, "Final Report: Air Emissions Controls Assessment – Holyrood Thermal Generating Station", February 2004

Meetings with Nalcor staff have indicated that the upgrade to low NOx burners has been under consideration for many years, on the assumption that future regulatory requirements would mandate their replacement. It is standard industry practice in North America to invest in NOx burner upgrades, which have a small capital commitment when installed along with other major emission control upgrades.

The level of detail in the studies for the addition of pollution control equipment was adequate, and the related cost estimates are reasonable and in line with industry norms.

6.5 Holyrood Thermal Generating Station Life Extension

Life extension of the HTGS was reviewed under both options. The initial Holyrood Phase 1 Condition Assessment and Life Extension Study (non-intrusive analysis) completed by AMEC does not address life extension requirements for the Isolated Island Option. The study of the life extension of the plant for continuous operation until 2015, and synchronous condenser operation until 2041, was detailed. It thoroughly reviewed the main equipment and systems and developed a detailed list of requirements for a more in-depth analysis, inspections, the tests required, and estimated costs associated with this work in phase 2 of the study. The study concluded that HTGS is a relatively modern design, is well maintained, and is in good condition for its age.

The costs included in the study are mainly related to the inspections and tests for Phase 2 of the life extension study. The life extension costs themselves are high level, and subsequent study phases would need to be completed to provide more detailed line item costs for components such as the marine terminal, transformers, and switchyard.

Meetings with Nalcor and responses to the Board's letter of July 12, 2011 (Exhibit 28) indicate that values included in the 2010 Capital Budget of \$100 million (\$20 million per year from 2012 to 2016) for the Holyrood Life Extension for the Isolated Island Option were not based on detailed engineering.⁶⁰ However, the values do offer a conservative order of magnitude representation of the sustaining capital required for the plant.

The CPW inputs also include HTGS life extension costs for major overhauls for Boilers No. 1 – 3 in 2015 – 2019, steam turbine overhaul costs in 2015 and 2016, as well as other minor upgrades in years 2024 and 2029⁶¹. This cost estimate provides a reasonable order of magnitude for life extension work of the HTGS plant to 2033/2036.

Based on industry experience, even with life extension, operation beyond 50 years to a maximum of possibly 60 years, with reduced reliability, may not be practical.

⁶⁰ Exhibit 28, Board Letter – July 12th, 2011

⁶¹ CE-39 MHI-Nalcor-1 CPWDetails

6.6 Holyrood Thermal Generating Station Replacement

For the Isolated Island Option, the HTGS plant replacement is planned to consist of three, 170 MW No. 2 low sulfur oil-fired CCCTs. The turbines would be installed in 2033 for Units 1 and 2, and in 2036 for Unit 3.

The cost for the first unit would be higher since there would be significant costs incurred for transmission connection, fuel supply, black start capability, etc. which would not be required for the 2nd and 3rd units. The resulting base cost estimate for the first unit included in Exhibit 5 Summary-Capital Costs Estimates is \$273.9 million.

MHI used GTPPro/Peace software, a well-known combined cycle heat balance and cost estimating program, to assess the plant installation costs in Nalcor's commissioned studies. The cost estimates and power output were found to be reasonable, with modifications applied to the cost for contingency and escalation.

6.7 Simple Cycle Combustion Turbines

CT installations on the island system in both options would have a nominal rating of 50 MW per unit and would be located either adjacent to existing thermal operations or at greenfield sites near existing transmission system infrastructure. Due to the high cost of operations, CTs are generally used for only short periods of time. Due to their low simple cycle efficiency, CTs are primarily deployed for system reliability and capacity support for peak demand. If required, CTs can be utilized to provide firm energy to the system.

The technology proposed and base value of \$55 to \$60 million for a 50 MW simple cycle No. 2 oil-fired CT installation appear reasonable and in compliance with industry estimates. The cost estimates are based on manufacturer supplied data.

6.8 Combined Cycle Combustion Turbines

A CCCT is more efficient than a simple cycle combustion 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. The higher efficiency makes it possible for CCCTs to be competitive for intermediate or base load applications. One of the primary benefits of a CCCT plant is that it can be used as base load power generation. CCCTs are typically configured using larger units of 170 MW.

The Isolated Island Option includes seven greenfield⁶² CCCT plant installations between 2022 and 2067. As discussed in Section 10 Volume 2, the CCCT Capital Cost study prepared by Hatch in 2008⁶³ was used to develop the base cost estimate for a 170 MW greenfield installations for both the Isolated

⁶² Definition of greenfield is an undeveloped site, especially one being evaluated and considered for commercial development or exploitation.

⁶³ CE-46 Rev.2 (Public), Hatch, "PM0011 – CCGT Capital Cost Benchmark Study Final Report", December 2008

Island and Infeed Options. The base cost estimate for the installations was escalated on average by approximately 2% per year to arrive at values used in the CPW analysis. MHI considers this estimate to be reasonable for the study purposes intended.

6.9 Holyrood Thermal Generating Station Synchronous Condenser Conversion

The feasibility study for converting Units 1 and 2 to synchronous condenser operation, Exhibit CE-56 Rev. 1 (Public), covered the main aspects of the electronics, controls, and generator and steam turbine modifications required to allow operation of the generators as synchronous condensers. Unit 3 already has the capability to operate as a synchronous condenser, and therefore conversion is not required.

MHI has concluded that the chosen technology is appropriate and that the cost estimate is acceptable.

6.10 Holyrood Thermal Generating Station Decommissioning

A detailed site assessment study has not been completed for HTGS by Nalcor. As a result, costs allocated for decommissioning the station are high level estimates. Using decommissioning estimates available to MHI from other projects, MHI has determined that the estimate of \$27.3 million used by Nalcor is reasonable.

It was noted in the response to RFI MHI-Nalcor-106 that Nalcor plans to continue using the Holyrood site for CCCTs. As a result, the site as a whole would not need to be remediated.

6.11 Thermal Assessment Key Findings

Key findings of MHI's review of thermal projects for both options are as follows:

- The thermal studies related solely to the Isolated Island Option were screening level studies, while there was a great deal more depth to studies of the Infeed Option. The level of detail of studies on upgrading the Holyrood Thermal Generating Station was found to be adequate, and the related upgrade costs are reasonable and in line with industry standards.
- Although the HTGS life extension costs for the Isolated Island Option are not based on detailed engineering studies, the estimates in the CPW analysis are conservative and representative of similar plants. This expenditure is needed to extend the life of the plant as a generating facility to 2033 for units 1 and 2, and 2036 for unit 3.
- Even with life extension under the Isolated Island Option, operating HTGS beyond 50 years, to a maximum of 60 years, with reduced reliability, may not be practical. There may come a point well before 2041 when the plant becomes unreliable to operate. The life extension plan and requirements under the Infeed Option are as follows:

- 2010 to 2017 Electricity Generation
 - 2017 to 2021 Electricity Generation, as-required primarily on a standby basis
 - 2017 to 2041 Synchronous Condenser Operation – Units 1 and 2 converted to synchronous condenser mode by 2017. Unit 3 is already synchronous condenser capable.
-
- The technology and base costs assumed for the 50 MW CT and the 170 MW CCCT installations are reasonable. The technology and costs assumed for replacing HTGS using CCCTs under the Isolated Island Option are reasonable based on present utility plant retirements for plants built in the late 1960's and early 1970's.
-
- A detailed site assessment study for decommissioning the HTGS has not yet been completed by Nalcor. The costs of decommissioning the station are high level estimates, but they are considered reasonable when compared to similar recent projects.

7 Cumulative Present Worth Analysis

Nalcor stated in its submission to the Board under its cover letter dated July 6, 2011⁶⁴:

"The outcome of the generation planning analysis is Cumulative Present Worth (CPW), which is the present value of all incremental utility capital and operating costs incurred Hydro to reliably meet a specific load forecast given a prescribed set of reliability criteria. Where the cost of one alternative supply future for the grid has a lower CPW than another, the option with the lower CPW will be recommended by Hydro, consistent with the provision of mandated least cost electricity service."

The metric of least cost was not defined by the government in setting out its mandate to the Board. The analysis provided by Nalcor is based on a Cumulative Present Worth (CPW) methodology which focuses exclusively on costs, including capital expenditures for the construction of new facilities, fuel costs and power purchased, and operating expenses. The CPW approach does not take cash inflows related to revenues into account. The goal of the least-cost analysis is to choose the Option which minimizes the present worth of costs.

When analyzing the least cost as determined by Nalcor, MHI reviewed all Nalcor exhibits and RFI responses that related to the calculation of the CPW figures, and developed a spreadsheet based on data from these various sources. This spreadsheet was used to better understand and evaluate Nalcor's assumptions and methodologies used in the CPW calculation. Over a subsequent series of RFIs submitted to Nalcor, MHI further assessed the specific details of the methodologies employed, both to evaluate the approach used to construct Nalcor's two Options and to look for possible mechanical or methodological errors.

The CPW results (2010\$) presented by Nalcor are summarized in Table 13. Analysis completed by MHI validated these results.

Table 13: Nalcor's CPW Breakdown for the two Options (\$ millions)

CPW Component	Isolated Island	Labrador Infeed
Operating and Maintenance	\$634	\$376
Fossil Fuel Costs	\$6,048	\$1,170
Existing Power Purchases	\$743	\$676
Muskrat Falls Power Purchases	NA	\$2,682
Depreciation	\$553	\$450
Return of Rate Base	\$831	\$1,297
Total	\$8,810	\$6,652
Differential	\$2,158	

(Source: Nalcor's Final Submission, Table 28, pg. 124)

⁶⁴ Nalcor, "Synopsis of 2010 Generation Expansion Decision", July 2011

7.1 Alternatives to CPW

Other types of analysis that are commonly used for determining the preferred option from a set of alternatives include Net Present Value (NPV) and Internal Rate of Return (IRR). Both of these methods require an estimate of the revenue stream generated by the power tariffs over the forecast period, as they weigh future cash in-flows related to revenue against cash out-flows, such as those associated with capital investment. These approaches rely on discounting future cash flows to the present and the result with the highest NPV is the preferred option. Differences in risk exposure are typically manifested in the choice of discount rate. MHI is satisfied that the CPW approach used by Nalcor is reasonable for the purpose intended, that being to identify the least cost choice between the two Options.

In summary, the least cost Option as defined by the use of CPW methodology is the Infeed Option. The CPW differential between the two Options is \$2.158 million.

7.2 PPA Versus COS Approach

In the process of discounting the costs for the CPW, Nalcor treated the costs related to the Muskrat Falls generation facility on a Power Purchase Agreement (PPA) basis, in contrast to a Cost of Service (COS) basis. The rationale provided by Nalcor for using a PPA approach was that the generation facility was to be developed by Nalcor who was then to act as an independent power producer and sell the energy to NLH. It also facilitated the costs associated with the Muskrat Falls Generating Station to be smoothed over the period under review. In contrast, using a COS approach tends to result in higher costs in the earlier years followed by lower costs in the latter years of a project. MHI tested the merits of using a full COS approach for Muskrat Falls Generating Station costs. Using an 8% interest rate for calculating AFUDC, the CPW using a COS approach is approximately equal to that using a PPA approach⁶⁵.

7.3 Discount Rate Sensitivity

MHI also tested the sensitivity of the level of discount rate used to discount the costs. Nalcor used a discount rate based on a weighted cost of capital of 8.0%, based on a weighting of 75% debt at 7.35% plus 25% equity at 10%. Recognizing there is some judgment applied in the selection of the appropriate discount rate, MHI tested the sensitivity of varying the discount rate and determined that within a reasonably close band, the level of discount rate does not substantially affect the CPW. In the extreme, the discount rate would have to be raised to 17% for the differential of the CPW between the two Options to become zero.

⁶⁵ Response to RFI PUB-Nalcor-177

7.4 Capital Cost Sensitivity

The sensitivity of accuracy as related to the capital costs, particularly as related to the Infeed Option, was also tested. Given the level of accuracy associated with DG2 estimates, the final capital costs have the potential to increase by as much as 50% over the current estimates. Should such a result occur, the differential of the CPW between the two Options would be reduced from \$2.158 billion to \$194 million⁶⁶.

Similarly, should the Labrador-Island Link capital costs increase by 25%, the CPW differential in favour of the Infeed Option would be reduced by \$398.0 million, and if the Muskrat Falls Generating Station capital costs increased by 25%, the CPW differential in favour of the Infeed Option would be reduced by \$577.0 million⁶⁷. If both the Labrador-Island HVdc Link and the Muskrat Falls Generating Station costs increase by 25%, the CPW differential in favour of the Infeed Option would be reduced by \$975 million⁶⁸.

7.5 Load Forecast Sensitivity

Another consideration which could have a significant impact on the resulting CPW relates to the assumption used for the load forecast. The assumption used for the Isolated Island Option was based on the same planning load forecast⁶⁹ (PLF) described in the 2010 Capital Budget Application to the Board, but extended to 2067. However, the significance of a possible alternate future for the remaining pulp and paper mill was not considered as an additional Isolated Island scenario. The PLF makes the assumption that there is no change in status for the mill. MHI requested Nalcor to perform a sensitivity analysis with a reduction in system consumption of 880 GWh per year, equivalent to the total electric energy requirement of the mill including purchases from Nalcor and their own generation. In Exhibit 43, revision 1, Nalcor indicated the CPW differential between the two Options would be reduced from \$2.158 billion in the base case to \$408 million in favour of the Infeed Option.

7.6 Fuel Price Sensitivity

Another consideration for the CPW analysis is the impact of fuel costs. In its analysis, Nalcor relies on forecasts of fuel oil prices provided by PIRA Energy Group of New York (PIRA), an international supplier of energy market fuel forecasts. PIRA provided reference, low, high and expected fuel forecasts with the reference price forecast being used by Nalcor. Using PIRA's March 2010 low fuel price forecast, the CPW differential is reduced to \$120 million from the \$2.2 billion presented by Nalcor in its base case⁷⁰. The forecasting accuracy for fuel costs will remain a challenge over the duration of the projected review period, which is in excess of 50 years. There are many variables which could come into play over that period that could have a substantial impact on fuel costs, over which Nalcor has no control or influence.

⁶⁶ Response to RFI PUB-Nalcor-118

⁶⁷ Response to RFI MHI-Nalcor-41

⁶⁸ Exhibit 43 Rev.1, Nalcor, "Newfoundland and Labrador Hydro – 2010 Generation Expansion Analysis (Revision 1)"

⁶⁹ Exhibit 16, Nalcor, "Generating Planning Issues 2010 July Update", July 2010

⁷⁰ Response to RFI MHI-Nalcor-41

7.7 Combined Input Sensitivities

Additional sensitivities were performed by varying multiple inputs. For example, if there is a 20% decrease in fuel costs, combined with a 20% decrease in the annual percentage load growth post 2014, and a 20% increase in the capital cost estimate for both Muskrat Falls Generating Station and the Labrador-Island Link HVdc system, the CPW differential would be reduced to \$159 million in favour of the Infeed Option⁷¹.

Also, should the existing pulp and paper mill cease operations, and its generation capacity be available for use on the system (880 GWh), and should the capital costs of both the Muskrat Falls Generating Station and Labrador-Island Link HVdc projects increase by 10%, the CPW for the two Options would be approximately equal⁷².

7.8 CPW Sensitivity Analysis Summary

With projects of this magnitude, and considering the length of the analysis period, there are risks and uncertainties associated with the key inputs and assumptions. Changes in these key inputs and assumptions will affect the financial results and must be assessed to determine materiality. These changes in key inputs and assumptions can impact the results of the analysis and shift the preference for what is the least cost option. Fuel costs and construction material costs are variable with world economic conditions. Load forecasts are a major input based on local conditions and must be carefully monitored to ensure that generation development occurs in relation to future load requirements.

Table 14 summarizes the results of various sensitivities. Increases in capital cost, load forecast reduction, or fuel price reduction could result in the favourable CPW differential for the Infeed Option being substantially reduced or even eliminated. Given the sensitivity of the load loss on the CPW, particularly in combination with potential variations in fuel price and capital cost estimates, MHI considers it imperative that Nalcor obtain as much understanding as possible regarding the future prospects for the continued operation of its industrial customers and in addition, develop contingency plans to address the implications of reductions in industrial loads.

⁷¹ Response to RFI PUB-Nalcor-56

⁷² MHI derived

Table 14: CPW Sensitivity Analysis Summary

	Sensitivity Summary	Isolated Island Option	Infeed Option	Difference
1	Base case	\$8,810	\$6,652	\$2,158
2	Annual load decreased by 880 GWh	\$6,625	\$6,217	\$408
3	Fuel costs: PIRA's low price forecast	\$6,221	\$6,100	\$120
4	Fuel price reduced by 44% from base case	\$6,134	\$6,134	\$0
5	Labrador-Island Link capital cost increased by 25%	\$8,810	\$7,050	\$1,760
6	Muskrat Falls GS capital cost increased by 25%	\$8,810	\$7,229	\$1,581
7	Muskrat Falls GS and Labrador-Island HVdc Link capital cost increase by 25%	\$8,810	\$7,627	\$1,183
8	Labrador-Island HVdc Link and Muskrat Falls capital cost increased by 50%	\$8,810	\$8,616	\$194
9	Scenario with <ul style="list-style-type: none"> Fuel cost decreased 20% Annual load growth decreased of 20% Capital cost increased for Muskrat Falls GS and Labrador-Island HVdc Link by 20% 	\$7,037	\$6,878	\$159
10	Scenario with <ul style="list-style-type: none"> Annual load decreased by 880 GWh Muskrat falls GS and Labrador-Island HVdc Link Capital cost increased by 10% 	\$6,625	\$6,598	\$27

(Sources:

Scenarios 1,2,3,4,5,6,7: Response to RFI MHI-Nalcor-41 Revision 1 and EX-43 Rev.1

Scenario 8: Response to RFI PUB-Nalcor-118

Scenario 9: Response to RFI PUB-Nalcor-56

Scenario 10: MHI derived)

In addition, the matter of meeting environmental guidelines in the future could be problematic. Nalcor stated that it may not be able to continue operating its oil fired generation facilities if a natural gas combined cycle benchmark for GHG emission intensity levels is applied to oil fired generation⁷³.

It is also noted, that while no consideration has been given to carbon pricing in either option, the impact of any future value of carbon credits will be more significant on the Isolated Island Option, which will lead to increasing the differential between the two Options.

⁷³ "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 2011, pg. 64.

7.9 CPW Analysis Key Finding

The key finding from the review of the CPW analysis is as follows:

- Based on the capital and operating costs estimated by Nalcor for each option and a common load forecast, Nalcor has determined that the Infeed Option has a lower cumulative present worth than the Isolated Island Option by approximately \$2.2 billion. The detailed analysis performed by MHI determined that Nalcor's cumulative present worth analysis was completed using recognized best practices and the cumulative present worth for each option was correct based on the inputs used by Nalcor. These inputs were reviewed in the technical and financial analyses conducted by MHI and were generally found to be appropriate. There are, however, other considerations related to risks associated with the assumptions used for certain key inputs such as load, fuel prices and cost estimates which may impact the cumulative present worth analysis for the two options. These were tested with the use of several sensitivity analyses and the results of these are summarized as follows:

- Load Forecast

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 of the Muskrat Falls Generating Station and Labrador-Island Link HVdc projects increase by 10%, the cumulative present worth for the two Options would be approximately equal⁷⁴.

- Capital Cost Estimates

The current capital estimates are within the accuracy of an AACE Class 4 estimate which has a plus factor variance potential of as much as 50%. Should cost overruns reach that level, the difference between cumulative present worth values for each of the two Options would be less than \$200 million in favour of the Infeed Option.

- Fuel Price

There remains significant uncertainty in fuel price forecasts. Global disruptions in supply could drive the price of oil well above inflation. However, new sources of supply, such as shale oil or downward trends in natural gas pricing, may have the potential to minimize fuel price increases.

If fuel prices drop by 44% below those used by Nalcor, the difference between the two cumulative present worth results becomes neutral. However, if fuel prices rise more

⁷⁴ MHI derived

than the reference price used in the cumulative present worth analysis, an even greater difference between the cumulative present worth results would occur.

The risks associated with these inputs are further magnified considering the 50+ year period (2010 – 2067) used in the preparation of the cumulative present worth analysis.

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8 Conclusion

Through a rigorous review of available technical and financial documents, meetings with Nalcor and their consultants, and responses to requests for information, MHI has undertaken an in-depth analysis and prepared this Report on the Isolated Island and Infeed Options for future generation expansion for the Island of Newfoundland. This Report is intended to assist the Board in its review and report to Government to address the Reference Question from the Lieutenant-Governor in Council.

A number of key findings are presented both in support and in critique of the work Nalcor has completed and MHI has made a number of recommendations. Except for the gaps identified in the key findings, particularly in the areas of reliability assessment, ac system integration studies, transmission line design criteria, and application of NERC standards, Nalcor's work has been performed largely in accordance with utility best practices. Further details on the key findings, gaps identified and recommendations are described in the relevant sections of the report.

As a result of the investigations based on the material, data, and assumptions provided by Nalcor, MHI finds that the Infeed Option is the least-cost option of the two alternatives reviewed. There are, however, risks associated with the assumptions used for certain key inputs such as load, fuel prices and cost estimates which may impact the CPW analysis for the two options. The risks associated with these inputs are further magnified considering the length of the period (2010 -2067) used in the preparation of the CPW analysis.



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