Date : 9/25/2012 12:23:46 PM
From : "Paul Wilson"
To : "Bown, Charles W."
Subject : MHI Muskrat Falls DG3 Review report (draft)
Attachment : MHI Muskrat Falls LIL DG3 Review report (draft).pdf;

Hello Charles, as requested here is a version marked draft with today's date. All markups have been removed and the copy is clean. The following revisions to pages 55 and 56 items are

"The Muskrat Falls Generating Station project contingency in the Decision Gate 3 estimate is 9.0%, but maybe higher with allowances if required. This has been discussed with the Nalcor project team, and the Nalcor project team believes that the current Decision Gate 3 estimates input detail and conservative assumptions justify the chosen contingency amount. Nalcor has noted that there is fixed pricing in place for approximately 25% of the project value, thus the 9% contingency is reasonable for Muskrat Falls Generating Station."

and

"The LTA Decision Gate 3 estimate includes a 9.1% contingency which is reasonable when combined with conservative inputs on labour and indirect costs."

Good luck!

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Manitoba
HYDRO INTERNATIONAL

Decision Gate 3
Review of the Muskrat Falls and Labrador Island HVdc Link and the Isolated Island Options

September 2012

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Decision Gate 3

Review of the Muskrat Falls and Labrador Island HVdc Link and the Isolated Island Options

Prepared for:
Hon. Jerome Kennedy, Q.C.
The Minister of the Department of Natural Resources
Government of Newfoundland and Labrador

Prepared by:
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September 25, 2012

DRAFT

Divisions of Manitoba Hydro International Ltd.

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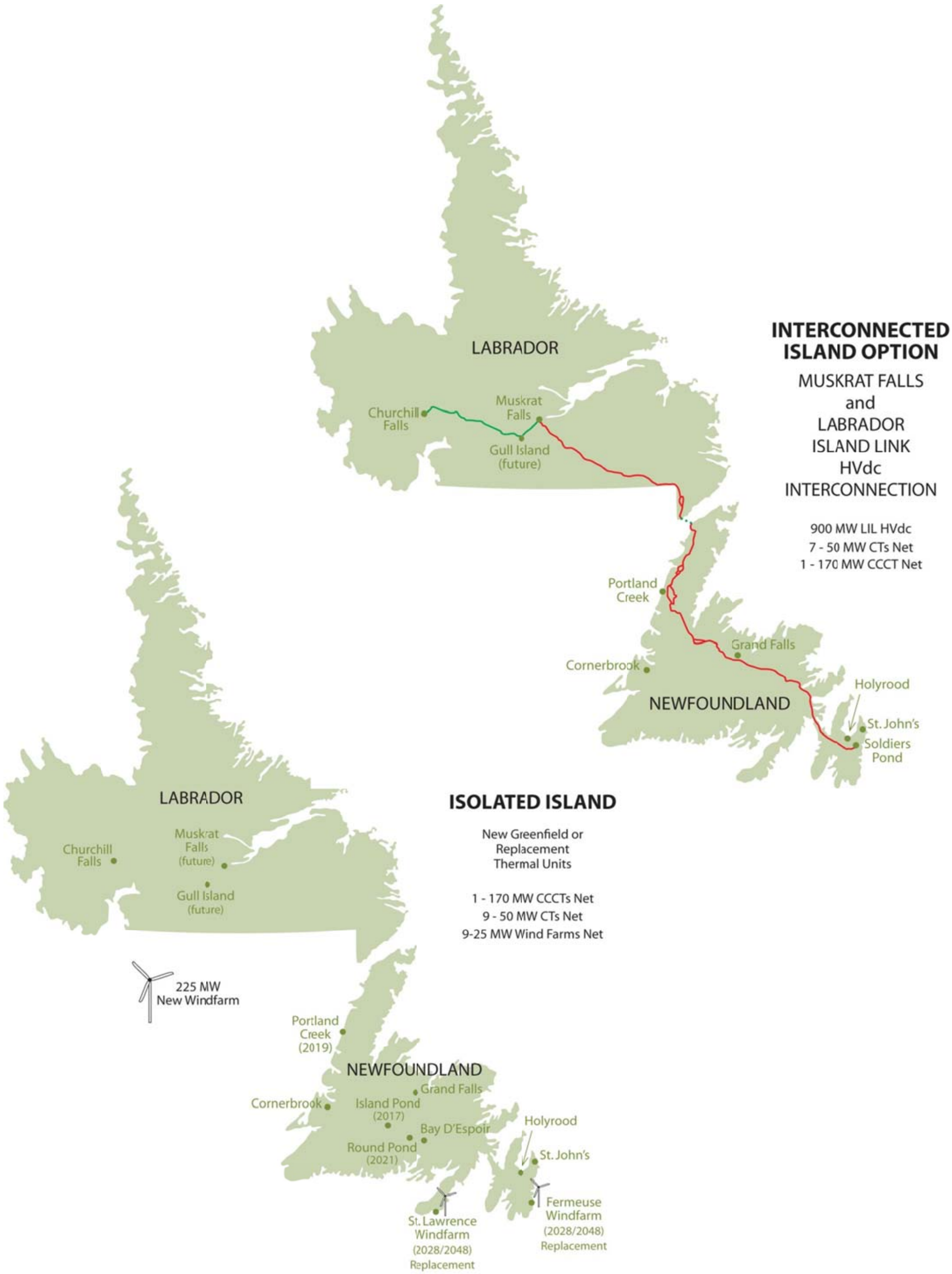
Professional Engineering and Geoscientists of Newfoundland and Labrador - No. 0474


INTERCONNECTED ISLAND OPTION
MUSKRAT FALLS
and
LABRADOR
ISLAND LINK
HVdc
INTERCONNECTION
900 MW LIL HVdc
7 - 50 MW CTs Net
1 - 170 MW CCCT Net
LABRADOR
Churchill Falls
Muskrat Falls
Gull Island (future)
Portland Creek
Grand Falls
Cornerbrook
NEWFOUNDLAND
Holyrood
St. John's
Soldiers Pond
ISOLATED ISLAND
New Greenfield or Replacement Thermal Units
1 - 170 MW CCCTs Net
9 - 50 MW CTs Net
9-25 MW Wind Farms Net
LABRADOR
Churchill Falls
Muskrat Falls (future)
Gull Island (future)
225 MW New Windfarm
Portland Creek (2019)
NEWFOUNDLAND
Grand Falls
Cornerbrook
Island Pond (2017)
Bay D'Espoir
Round Pond (2021)
Holyrood
St. John's
St. Lawrence Windfarm (2028/2048) Replacement
Fermeuse Windfarm (2028/2048) Replacement

Executive Summary

Manitoba Hydro International Ltd. (MHI) has reviewed the technical material and cumulative present worth estimates provided by Nalcor to MHI for two power supply options to serve the forecasted load in Newfoundland and Labrador until 2067.

One of the options, known as the Interconnected Island option because power would be fed to the Island of Newfoundland, is largely a hydroelectric generation plan, with 824 MW from a hydroelectric generating station and 670 MW from thermal generating stations. The thermal plants are largely used to provide reliability and capacity support to the system and are only used when operational contingencies arose. Power from Muskrat Falls Generating Station on the Lower Churchill in Labrador would be fed to Newfoundland over the Labrador Island Link HVdc transmission line that will cross the Strait of Belle Isle. The cumulative present worth (CPW) of the Interconnected Island option was estimated at $8,366 million in 2012 dollars.

The other option, known as the Isolated Island option because all generation would originate in Newfoundland, is largely a thermal generation plan, with 1,890 MW from thermal generating stations, 77 MW from mini-hydroelectric generating stations, and 279 MW from wind farms. The CPW of the Isolated Island option was estimated at $10,778 million in 2012 dollars.

The current review of the options was based on material provided by Nalcor since November 2010 in preparation for Decision Gate 3, the milestone to give project sanction. To perform this review, MHI assembled a team of specialists with expertise in load forecasting, risk analysis, hydroelectric generation, HVdc engineering, system planning, and financial analysis. As part of the review process, team members met with Nalcor representatives and their consultants to review the new information available on the options.

Several key findings on Nalcor's work came to light during MHI's current review. They are highlighted here to help convey the depth and extent, and reasonableness, of the refinements made to the two options.

Key Findings

Interconnected Island Option

The Interconnected Island option for Decision Gate 3 has the following component mix: a 900 MW Labrador Island HVdc link, a total of ten 50 MW CTs (combustion turbines) installed of which three are replacements, and one 170 MW CCCT (combined cycle combustion turbines). There was some realignment of the generating station at Muskrat Falls as a result of detailed design modeling. Nalcor also specified the size of the synchronous condensers to support the Labrador Island Link HVdc system.

Load Forecast. The Load Forecast for the Interconnected Island option showed an increase in domestic load for the period to 2029, which was expected due to higher economic forecasts for personal disposable income and population. However, the general service sectors show a decrease, which would appear to be conservative as it normally mirrors domestic load. The industrial load does not include any new accounts over the entire time-span, which is very likely conservative. MHI finds that the Load Forecast for the Interconnected Island option is well founded and appropriate as an input into the Decision Gate 3 process.

AC Integration Studies. MHI's review of the ac integration studies for the Interconnected Island option indicates that Nalcor is in compliance with good utility practices. It also found that there is an opportunity, during detailed design, to optimize final configurations that may enhance system reliability.

HVdc Converter Stations. An assessment of the technical work completed by Nalcor and its consultants on the HVdc converter stations, electrode lines, and associated station equipment showed the work was reasonable as an input to the Decision Gate 3 process. MHI has notified Nalcor of some project improvements which could be made during the detailed design phase, with little impact on the CPW result.

HVdc Transmission Line, Electrode, and Collector System. MHI reviewed the cost estimates, construction schedules, and design methodologies undertaken by Nalcor and its consultants for the HVdc transmission line, electrode, and collector system. In our opinion, Nalcor has used a reasonable approach in designing the transmission line to withstand many unique and severe climatic loading conditions along its length. However, MHI continues to support selection of a 1:150 year return-period due to the criticality of the HVdc transmission line to the Labrador and Newfoundland electrical system.

Strait of Belle Isle Crossing. MHI's review of the work completed by Nalcor and its consultants has shown that the design definition and concept of the configuration of the marine crossing are well founded. Further bathymetric work and a test borehole have shown that costs have increased only marginally. MHI considers that the marine crossing is viable, within the AACE Class 3 estimate range, and that it can be completed as planned within the allotted time frame.

Muskrat Falls Generating Station. The cost estimates, construction schedules, and design work undertaken by Nalcor and its consultants were reviewed as part of the Decision Gate 3 process. The proposed schedule is appropriate and consistent with best utility practices. Based on the amount of engineering completed and on the number of tenders for which estimates have been provided by potential suppliers, MHI considers the Decision Gate 3 cost estimate to be an AACE Class 3 and thus would be considered reasonable for a Decision Gate 3 project sanction. The Labrador transmission assets have also been appropriately designed and scheduled, and the cost estimate for them is consistent with good utility practice.

Isolated Island Option

The Isolated Island option, for Decision Gate 3, is comprised of the following generation resource mix of seven 170 MW CCCTs (net one new), fourteen 50 MW CTs (net 9 new), 77 MW of small hydroelectric plants, and 279 MW (net 225 MW new) of wind farms.

The load forecast for the Isolated Island option is somewhat less than the Interconnected Island option due to the higher marginal price of electricity. However, the general service sectors show a decrease, which would appear to be conservative as it normally mirrors domestic load. MHI finds that the Load Forecast for the Isolated Island is well founded and appropriate as an input into the Decision Gate 3 process.

Holyrood Thermal Generating Station. The Holyrood Thermal Generating Station is assumed to remain in full operation until 2036, with upgrades taking place as previously committed. Pollution control equipment was also scheduled to be installed by 2018. Vendors were canvassed for actual costs of equipment, and fuel oil prices were updated to reflect 2012 PIRA estimates.

The Holyrood Thermal Generating Station will be replaced with three 170 MW CCCTs, which are then subsequently replaced every 30 years. Estimates have been updated to reflect this change in operation.

Wind Farms. Wind farms are not deployed in the Interconnected Island option because surplus energy is available from Muskrat Falls Generation Station. In the Isolated Island option, a significant amount of wind power has been added, replacing a portion of the generation supplied by thermal generation operating on base load, as recommended in the external 2012 Hatch study.

MHI studied the proposed wind plan for inclusion into the Isolated Island option, as a separate project. The report for this study will be published under separate cover "Decision Gate 3 Review of the Wind Study for the Isolated Island of Newfoundland". The new generation master plan allows for up to 279 MW (including the existing 54 MW) of total wind capacity on the Island as part of the Isolated Island option.

MHI has reviewed the costs associated with the fixed charges and operating expenses of the wind farms used in the Isolated Island option. It finds them reasonable as inputs into the CPW analysis.

Simple and Combined Cycle Combustion Turbines

In the Interconnected Island option, there are ten 50 MW peaking units to match the increase in expected load, along with one 170 MW combined cycle unit. For Decision Gate 3, costs for the CCCT were upgraded for the analysis, with input from consultants and vendors.

The Isolated Island option is comprised of fourteen 50 MW CT peaking units with seven base-load 170 MW CCCT units, plus 225 MW of wind capacity. While there was no change in the types of units specified, there was an upgrade of costs to reflect current market prices.

Small Hydroelectric Plants

There are no changes in the configuration of any of the three small hydroelectric generating stations to be developed for the Isolated Island option. Island Pond Generating Station and Portland Creek Generating Station were updated to current costs, whereas additional work was undertaken on Round Pond Generating Station to update a 23-year-old study. The costs presented for all three plants are reasonable as AACE Class 4 estimates and suitable as input in the Decision Gate 3 analyses.

Financial Analysis of Options

Both the Interconnected Island and Isolated Island options have been updated to reflect current market conditions and cost inputs for the Decision Gate 3 analysis. The preference for the Interconnected Island option is $2.4 billion over the Isolated Island option. This work included a re-evaluation of fixed charges, operating costs, fuel costs, and power purchase costs. The cost estimates were conducted by consultants working with staff and management from Nalcor. Costs of both options have increased as a result of escalation and scope changes. With the assumptions and inputs provided by Nalcor to MHI, the Interconnected Island option remains the least cost option to meet the needs for capacity and energy to supply the forecasted load in Newfoundland and Labrador until 2067.

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

It is important to note that any monetization of excess power from Muskrat Falls to external markets was not factored into MHI's Decision Gate 3 analysis; the monetization is expected to improve the overall business case of the Interconnected Island option. Also, any uncommitted energy from Muskrat Falls would allow Nalcor to more easily address any future large load additions to the Island of Newfoundland or to Labrador.

There remains significant uncertainty in fuel price forecasts, which are magnified over the 50-plus years of the study horizon. The Interconnected Island option has much less exposure to variances in fuel prices.

Conclusions

MHI has found Nalcor's work to be skilled, well-founded, and in accordance with industry practices. The result of the CPW analysis indicates a preference for the Interconnected Island option of $2.4 billion over the Isolated Island option. Both options have increased substantially in cost due to escalation and scope change from prior estimates released in November 2010. However, the Interconnected Island option continues to have a lower present value cost given the full range of sensitivity analyses and inputs provided by Nalcor. MHI therefore supports Nalcor's finding that the Interconnected Island option is the least-cost option of the two.

Nothing was found in any of the technical or financial reviews that would substantially change MHI's findings under the existing assumptions.

Although beyond the scope of the review, MHI also concluded that a planned new connection of Newfoundland's power system to the North American grid is not only expected to improve reliability of the province's system but also increase provincial power revenues, given that Muskrat Falls would generate more electricity than required by the province for the next two decades.

Recommendations

Given the analysis that MHI has conducted based on the data and reports provided by Nalcor, MHI recommends that Nalcor pursue the Interconnected Island option as the least cost alternative to meet future generation requirements to meet the expected electrical load in Newfoundland and Labrador.

Table of Contents

1 Introduction

The Government of Newfoundland and Labrador retained Manitoba Hydro International Ltd. (MHI) to provide an independent technical assessment of two generation supply options, as prepared by Nalcor Energy (Nalcor), for the future supply of electricity to the Island of Newfoundland. The two generation supply options are the Interconnected Island option and the Isolated Island option. The scope of this assessment is limited to Nalcor's revisions to the two generation supply options following Decision Gate 2 (DG2), from November, 2010. MHI's assessment is summarized in this current report, and will be used in preparation for Decision Gate 3 (DG3) or project sanction.

The Decision Gate process is a project management process designed to allow effective decision making for projects. Nalcor has passed the Decision Gate 2 milestone November 2010 and the next stage gate or Decision Gate 3 is the milestone to determine whether to proceed with the project. Decision Gate 3 is also referred to as project sanction.

MHI's report is preceded by a report prepared by the Newfoundland and Labrador Board of Commissioners of Public Utilities dated March 30, 2012[1]. The Board's report reviewed the two generation supply options for the Government of Newfoundland and Labrador to determine whether the Interconnected Island Option represented the least-cost option for the supply of power to the Island Interconnected customers over the period of 2011-2067 as compared with the Isolated Island option. The Board's report also embodied the work done by Manitoba Hydro International as their independent expert as part of the Decision Gate 2 review.

MHI's review of the work completed by Nalcor in preparation for Decision Gate 3 includes an assessment of the Cumulative Present Worth (CPW) analysis of the various components for each of the two options, including a reasonableness assessment of all inputs into that analysis. The tests of reasonableness for this assessment are generally defined as the work following:

- Good project management and execution practices
- Good utility practices of the majority of electrical utilities in Canada, while recognizing the unique electrical isolated system on the Island of Newfoundland and commonly accepted practice in Newfoundland and Labrador regarding the electrical system. Any practices unique to Newfoundland and Labrador are noted in this report. The review and technical assessment in the context of this scope of work determines if Nalcor's

[1] Board of Commissions of Public Utilities, "Reference to the Board – Review of Two Generation Expansion Options for the Least-Cost Supply of Power to Island Interconnected Customers for the Period 2011-2067", March 30, 2012.

work was undertaken in accordance with good utility practices whereby the processes, practices, and standards used in the development of the work follows generally acceptable practices, standards, and processes of a majority of the utilities in Canada.

A comparison of the two generation supply alternatives; the Interconnected Island option and the Isolated Island option, are outlined on pages 7 and 8 (Figure 1 and Figure 2).

Over the study period, the Interconnected Island option is largely a hydroelectric generation plan (824 MW from the Muskrat Falls Generating Station and the 900 MW Labrador-Island Link HVdc system, with the addition of 10 – 50 MW CTs and one 170 MW CCCT (520 MW net) of thermal generation for capacity reserve. Power from the Muskrat Falls Generating Station on the Lower Churchill River in Labrador is planned to be supplied to Newfoundland over the Labrador-Island Link HVdc system transmission line that would cross the Strait of Belle Isle. The target for first power from the Muskrat Falls Generating Station is scheduled to be available in July 2017.

Similarly, the Isolated Island option is largely a thermal generation plan (620 MW net), with the addition of 77 MW of small hydroelectric-generating stations and 225 MW net of new wind power. The generation plan includes:

- Installation of environmental emissions controls at Holyrood (electrostatic precipitators, scrubbers and NOx burners) as per the Newfoundland and Labrador Government's policy directives
- Life extension projects at Holyrood which is replaced by three 170 MW combined-cycle combustion turbines in 2032, 2033 and 2036.
- 23 – 25 MW, plus four 27 MW of wind farm (279 MW net)
- The 36 MW Island Pond Generating Station
- The 23 MW Portland Creek Generating Station
- The 18 MW Round Pond Generating Station
- Nine 50 MW combustion turbines (450 MW net)
- One 170 MW combined-cycle combustion turbine (170 MW net)

This review of the two generation supply options includes a more in-depth examination of the transmission line designs, ac integration studies, and HVdc converter station plans, as this material has been recently prepared for Decision Gate 3. MHI's focus for the Muskrat Falls Generating Station, the Strait of Belle Isle marine crossing, and thermal power plants was limited to a detailed review of cost estimates and schedule as it relates to the project definition. The technical comments contained in this report are offered for Nalcor's consideration based on review of the available material, meetings with Nalcor, and MHI's past experience on similar projects. Comments of a significant nature that could potentially lead to impacts on the result of the CPW analysis are highlighted; the balance of the comments are for Nalcor to consider as part of the detail design process post-Decision Gate 3.

For Decision Gate 3, the cost estimate accuracy range for all engineering estimates for the Muskrat Falls Generating Station and the Labrador-Island Link HVdc system was the Association for the Advancement of Cost Engineering (AACE), Class 3 estimate range. For the Isolated Island option, some costs were updated, whereas others were escalated to provide new base case numbers at the AACE Class 4 level similar to that used for Decision Gate 2.

This report is organized with the major elements of the Interconnected Island option being discussed first in Section 2. The items related to the Isolated Island option are discussed in Section 3, with the CPW financial analysis described in Section 4. A number of documents have been provided to MHI by Nalcor to assist in this review.

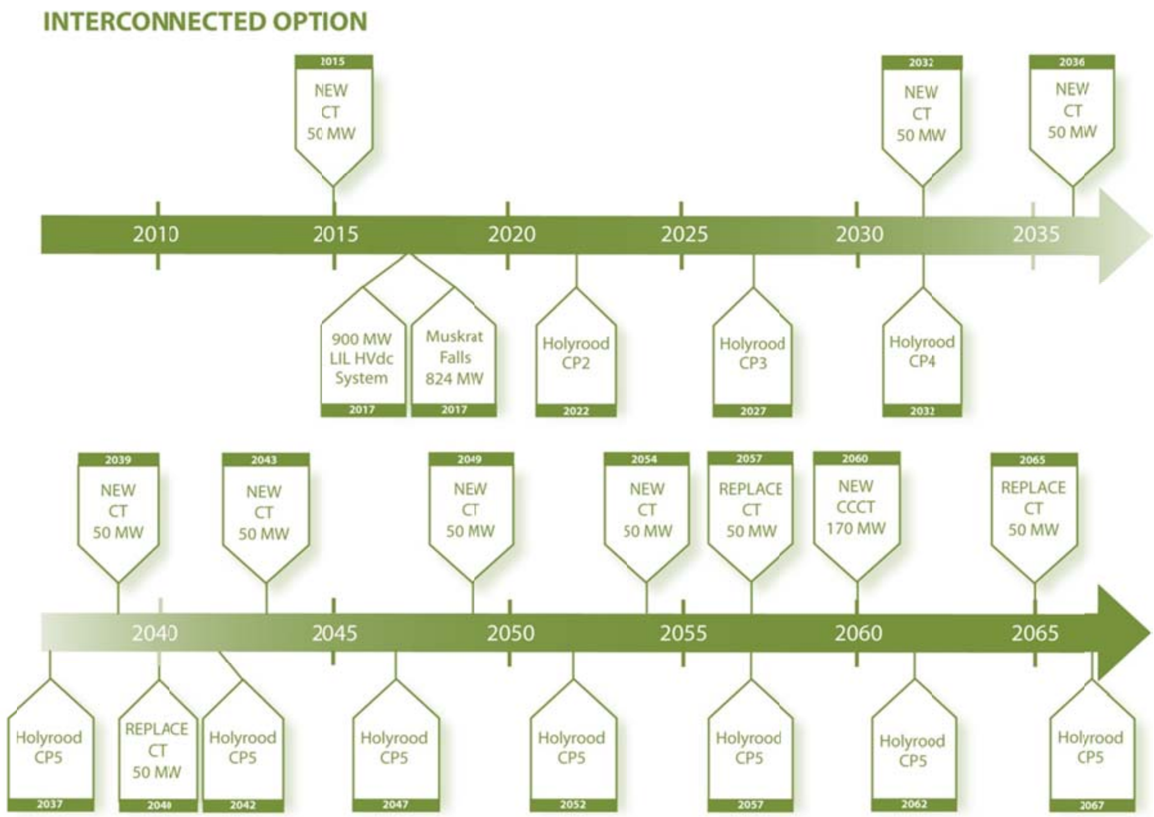


Figure 1: Project Time Line - Interconnected Island Option

The Interconnected Island option encompasses several generation items that are added to the system according to the generation master plan. These items and installation dates are shown in Figure 1. The timing and sizing of new generation sources are a result of the Strategist Software. This plan is essentially the same as the previously published plan with differences in plant timings. Holyrood sustaining capital for unit 3 synchronous condenser operation and plant decommissioning costs have been noted as Holyrood CP2 through 5.

The Isolated Island option as detailed in Section 3 encompasses several generation items that are added to the system according to the generation master plan. These items and installation dates are shown in Figure 2 below.

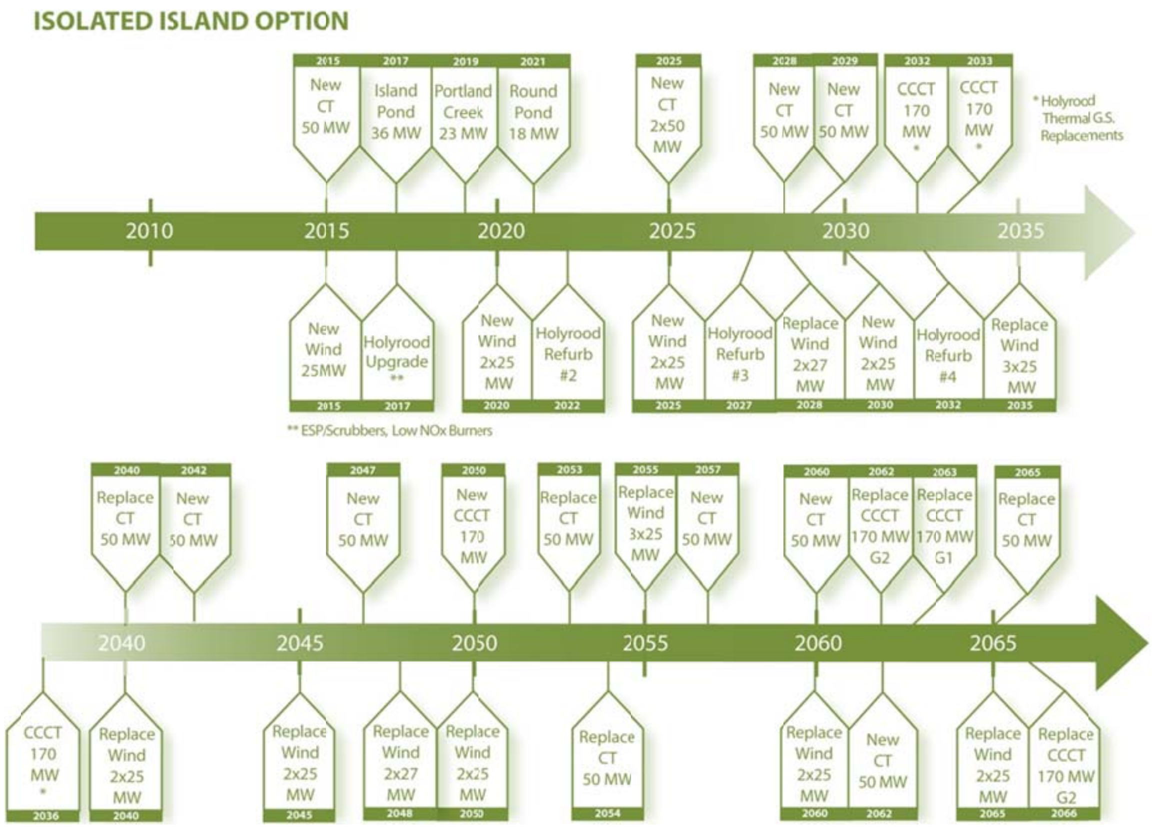


Figure 2: Project Time Line - Isolated Island Option

2 Interconnected Island Option

The Interconnected Island option is depicted in Figure 3 showing the HVdc transmission system, and important elements as part of the generation resource plan.

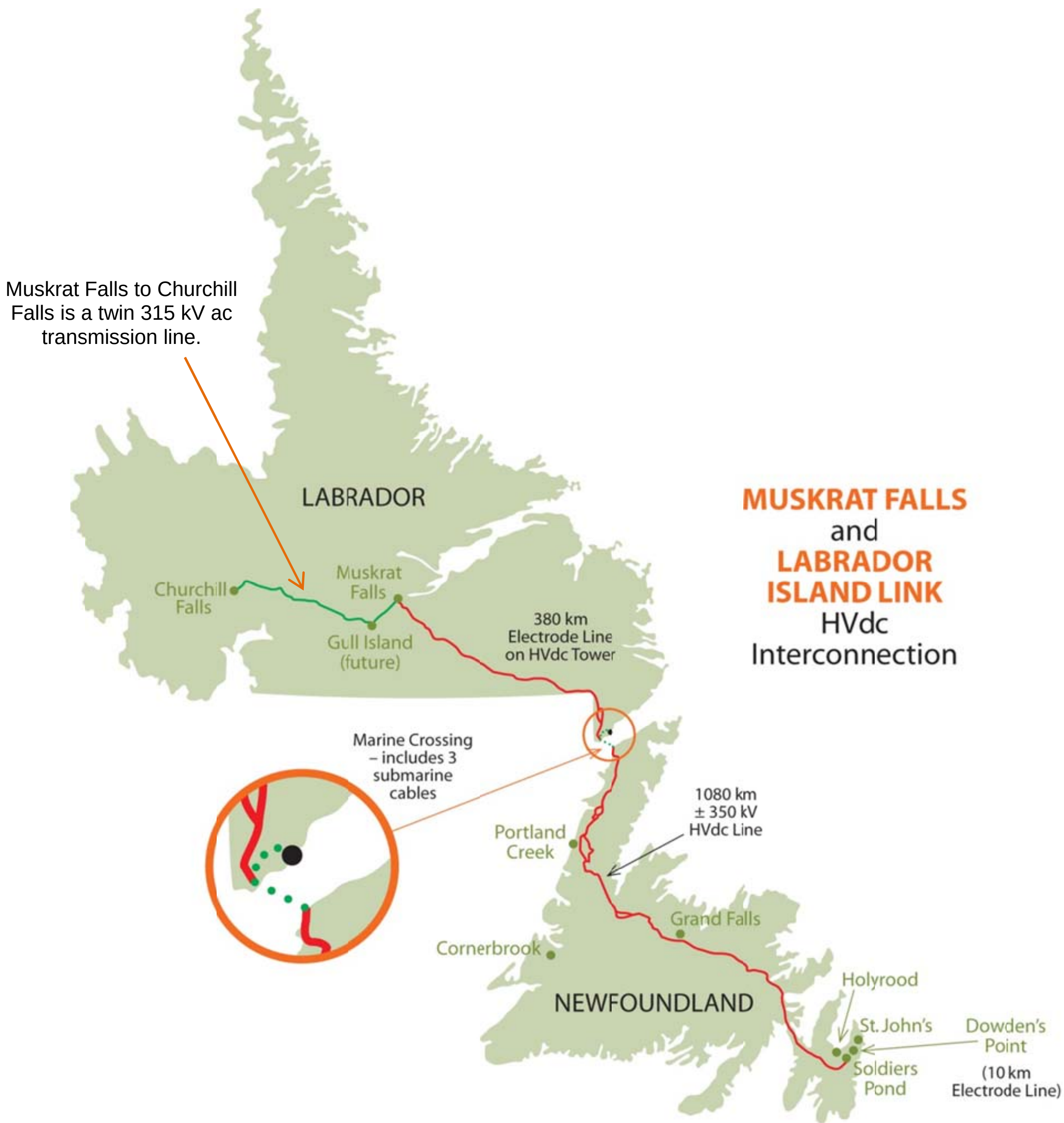


Figure 3: Interconnected Island Details

This section of the report describes the Load Forecast, ac integration studies undertaken by Nalcor, HVdc converter station and associated equipment, transmission system elements, the Strait of Belle Isle marine crossing, Muskrat Falls generating station, and other thermal and small generation sources added for this option. Detailed examination of the hydrology, reliability studies, or thermal supply options have been previously carried out and deemed not required as part of MHI's Decision Gate 3 review.

2.1 Interconnected Island Load Forecast

The purpose of this section is to analyze the 2012 Interconnected Island option to determine whether it was conducted with the due diligence, skill and care expected from an operation of this magnitude. Based on a number of documents provided by Nalcor to MHI, this section outlines the differences between the Load Forecast for 2012 Interconnected Island option and that prepared in 2010, compares levels of forecast growth versus historical growth, and updates the forecast accuracy tables. The analysis focuses on the total electric energy peak requirements on the Island of Newfoundland. The data reviewed focuses on the 20-year forecast period (2012-2031). The extrapolated forecast (from 2031-2067) is also reviewed for total Island energy requirements and interconnected Island system peaks.

2.1.1 Comparison of the 2012 Interconnected Island Option Load Forecast and the 2010 Load Forecast

This analysis compares the forecasts prepared in 2010 and 2012 where the 2012 Interconnected Island Load Forecast is being used as the basis for Decision Gate 3. Generally, the 2012 energy and peak forecasts are higher over the 20-year forecast period. The 2012 energy and peak forecasts converge towards 2010 forecast levels over the extrapolation period and cross over around 2057 (see Figure 4 and Figure 5).

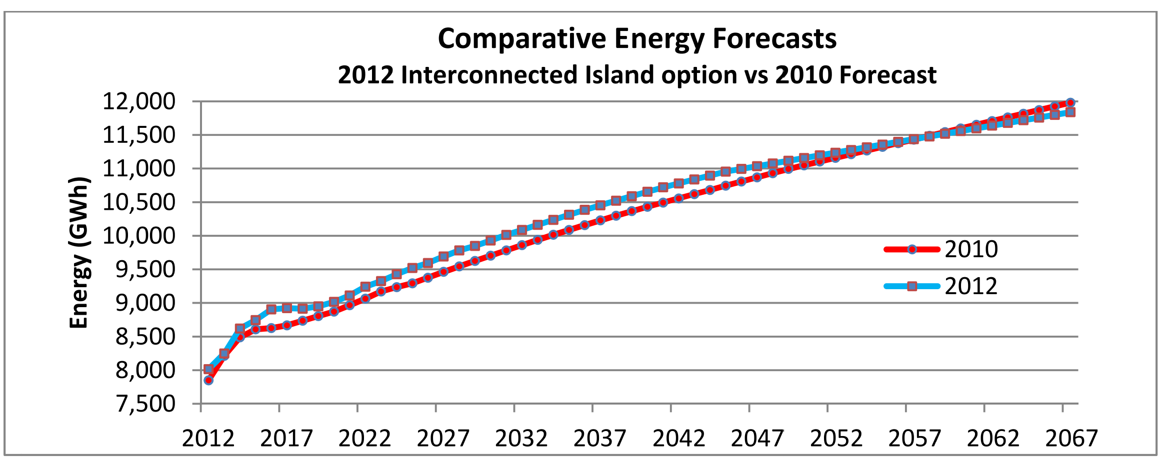


Figure 4: Comparative Energy Forecasts - the 2012 Interconnected Island option versus 2010 Load Forecast

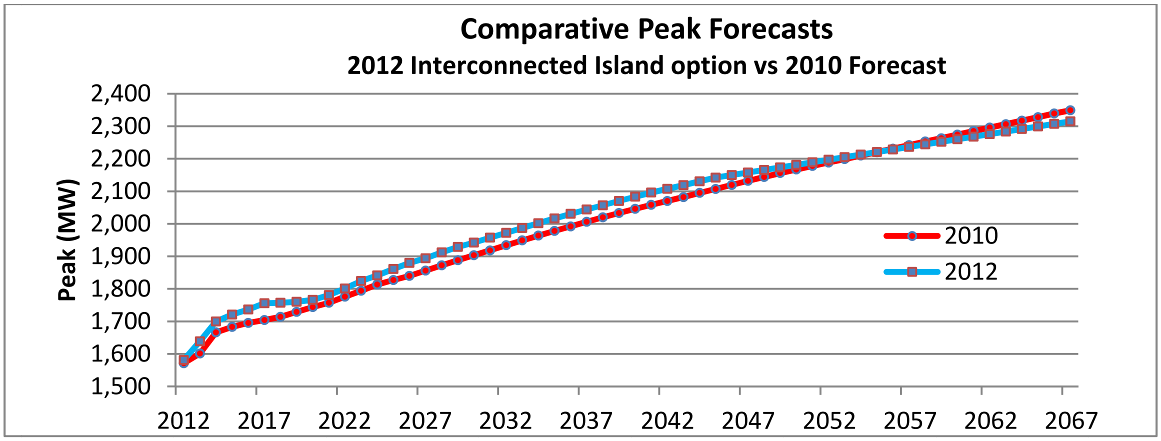


Figure 5: Comparative Peak Forecasts - the 2012 Interconnected Island option versus 2010 Load Forecast

Since the econometric sector forecasts prepared in 2010 covered the period of 2010 to 2029, this comparative analysis has a forecast start year of 2012, a forecast mid-point year of 2020, and a forecast long-term year of 2029. The results are included in Table 1.

Table 1: Comparison of the 2012 Interconnected Island option and the 2010 Forecast - Net Difference

	Energy (GWh)					Peak (MW)
Year	Domestic	General Service	Industrial	Other	Energy	
2012	177	-4	-53	44	164	10
2020	160	-67	37	14	144	22
2029	326	-156	37	14	222	41

In the year 2012, the 2012 Interconnected Island option predicts that total Island energy and peak requirements will be greater than the 2010 Load Forecast by 164 GWh and 10 MW, respectively. This increase is the result of a higher actual domestic load growth experienced in 2010 and 2011, caused by a significant number of new domestic customers and an increase in domestic weather-adjusted average use.

By 2029, the 2012 Interconnected Island option predicts that total Island energy requirements will be greater than the 2010 Load Forecast by 222 GWh. This increase is due to the higher domestic sector forecast, by 326 GWh, which is the result of a higher customer forecast and a higher average-use forecast.

Table 2 lists the differences between the 2012 Interconnected Island option and 2010 Load Forecast for the key economic assumptions and domestic consumption variables for the 2029 forecast long-term year. The higher domestic forecast for the 2012 Interconnected Island option (by 326 GWh) was due to a lower marginal price of electricity forecast (-1.17 cents), which will encourage electricity consumption such as electric space-heating, and the revised key economic assumptions as prepared by the Newfoundland Department of Finance, which raised forecasts for personal disposable income (by $1,501) and population (by 6,500). By 2029, the domestic average-use forecast was increased by 984 kWh in the 2012 Interconnected Island option, primarily due to a lower marginal price of electricity forecast, a higher saturation of electric space-heating forecast (2.0%), and a higher Personal Disposable Income (PDI) per customer forecast. By 2029, the domestic forecast predicted a greater number of total customers (3,496) and electric space-heating customers (7,437), primarily due to a higher actual customer growth in 2010 and 2011 than previously forecast.

Table 2: Comparison of the 2012 Interconnected Island option and 2010 Load Forecast in 2029 - Net Difference

Forecast	Avg Use	Electric Space Heat Cust.	Total Cust.	Electric Space Heat%	Marginal Price	PDI ($)	Population	CBI (000s)
2012 Interconnected Island option	17,015	178,824	254,627	70.2%	8.72	$15,196	513,200	$21,857
2010 Load Forecast	16,032	171,387	251,131	68.2%	9.89	$13,695	506,700	$22,797
Difference	984	7,437	3,496	2.0%	-1.17	$1,501	6,500	($940)

MHI considers the significant increase in the domestic forecast as an improvement over the 2010 Load Forecast because the 2012 Interconnected Island option is based on the higher customer growth and higher weather-adjusted average-use growth experienced over the last two years. The 2012 Interconnected Island option is also based on higher personal disposable income and population forecasts, which MHI considers more reasonable.

The higher domestic forecast was offset by a general service forecast that was 156 GWh lower, caused by a lower commercial business investment forecast, provided by the Department of Finance. The decrease in Commercial Business Investment (CBI) is questionable, considering that most other key economic assumptions were increased. Usually, an increase in the number of domestic customers and their relative prosperity will lead to an increase in general service investment and general service electricity consumption. ***Consequently, MHI considers the general service forecast prepared in 2010 as more reasonable and representative of an economy with moderate, consistent growth.***

The industrial forecast was 37 GWh higher due the combination of a higher energy consumption forecast for Vale Newfoundland and Labrador Limited (Vale) and a lower energy consumption forecast for Corner Brook Pulp and Paper Limited (Corner Brook mill). The other sector forecast, which consists primarily of distribution and transmission losses, was increased by only 14 GWh. System losses will increase as a result of higher total electricity sales.

By 2029, the 2012 Interconnected Island option predicts that the total Island interconnected peak will be 41 MW more than the 2010 Load Forecast. This increase is the result of a higher electric space-heating customer forecast and a lower marginal price of electricity forecast. MHI considers the increase in the peak forecast as an improvement over the 2010 Load Forecast because the 2012 Interconnected Island option is based on a higher number of electric space-heating customers.

By 2020, the 2012 Interconnected Island option predicts that total Island energy and peak requirements will be greater than the 2010 Load Forecast by 144 GWh and 22 MW, respectively. The domestic forecast was increased by 160 GWh, the general service forecast was decreased by 67 GWh, the industrial forecast was increased by 37 GWh, and the other sector forecast was increased by 14 GWh. Generally, the differences in the 2020 forecast mid-point year are caused by the same factors that explained the differences for the 2029 forecast long-term year.

2.1.2 Comparison of the 2012 Interconnected Island Option with Historical Growth

Table 3 compares the 2012 Interconnected Island option with historical growth. Total Island energy and peak requirements are expected to grow at a steady rate over the next 20 years. These forecasted growth levels are very similar to the historical growth experienced over the last 40 years. One apparent concern is that the total Island energy and peak forecasts over the extrapolation period (from 2031 to 2067) are too low. The extrapolated energy forecast (51 GWh) is only 44% of the load expected over the 20-year forecast growth rate (115 GWh). The extrapolated peak forecast (10 MW) is only 48% of the load expected over the 20-year forecast growth rate (21 MW). These reductions in future growth are significant and may be overly conservative. For example, the 10 MW of annual peak growth can be achieved by adding only 1,565 electric space-heating customers per year, which is much lower than the average addition of 3,551 electric-space heating customers per year over the last ten historical years (2001-2011). The extrapolated growth rates are lower due to lower growth of electric space-heating as the market becomes saturated and the assumption that no new industrial loads will locate on the Island over the extrapolation period.

Table 3: Annual Growth per Year – The 2012 Interconnected Island option and Historical Growth

Sector	Historical Growth Rate			Interconnected Island option	
				Forecast Growth Rate	Extrapolated Growth Rate
	1971-2011 (40-Year)	1991-2011 (20-Year)	2001-2011 (10-Year)	2011-2031 (20-Year)	2031-2067 (36-Year)
Domestic (GWh)	77	42	65	56	NA
General Service (GWh)	44	24	32	21	NA
Industrial (GWh)	-13	-58	-132	31	NA
Other (GWh)	8	3	13	7	NA
Island Energy (GWh)	117	12	-23	115	51
Island Peak (MW)	25	3	11	21	10

The 20-year forecast growth rate for the domestic sector (56 GWh) is expected to be less than the 10-year historical growth rate (65 GWh). This is because most electric space-heating conversions have already occurred, so fewer conversions are expected in the future. Conversely, the 20-year forecast growth rate is expected to be greater than the 20-year historical growth rate (42 GWh). This is because the economy is expected to outperform the historical period that included the economic downturn of the 1990s. ***MHI considers the 20-year forecast growth rate for the domestic sector to be reasonable.***

The 20-year forecast growth rate for the general service sector (21 GWh) is expected to be similar to the 20-year historical growth rate (24 GWh). However, the historical growth rate covered a period of economic downturn in the 1990s, and since another economic downturn is not anticipated in the future, the 2012 Interconnected Island option forecast for the general service sector seems to be conservative. MHI considers the 2010 Load Forecast for the general service sector to be more reasonable and representative of an economy with moderate, consistent growth. By 2029, the 2010 Load Forecast predicts that the general service load will increase by 156 GWh, or 8 GWh per year, over the 20-year forecast period. This would raise the 20-year forecast growth rate to 29 GWh per year, which would be similar to the 10-year historical general service growth rate (32 GWh).

The 20-year forecast growth rate for the industrial sector (31 GWh) is expected to grow due to the expansion of Vale and the assumption of continued operation of the Corner Brook mill.

The 20-year forecast growth rate for the other sector (7 GWh) is expected to be similar to the 40-year historical growth rate (8 GWh). The 20-year forecast growth rate for total Island energy (115 GWh) is expected to be similar to the 40-year historical growth rate (117 GWh). The 20-year forecast growth rate for total Island peak (21 MW) is expected to be 16% lower than the 40-year historical growth rate (25 MW).

2.1.3 Forecast Accuracy

A reasonable performance measure for forecast accuracy is a maximum forecast deviation of ±1% per year. A 10-year-old forecast, for example, should be within ±10% of the actual energy load observed. Table 4 measures forecast accuracy in terms of percentage of deviation from the actual load.

Table 4: 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 (%)	-1.4	-2.2	-3.2	-3.9	-4.4	-4.8	-6.0	-7.4	-8.5	-10.2
General Service (%)	0.1	0.1	0.1	0.3	0.2	0.4	0.3	0.5	1.5	2.5
Industrial (%)	5.0	13.3	26.0	40.8	59.6	70.4	88.0	100.5	122.4	125.3
Other Loads (%)	-3.1	-4.3	-5.0	-6.7	-7.9	-8.7	-8.1	-7.6	-7.1	-9.2
Island Energy (%)	0.3	1.7	3.5	5.8	8.7	10.4	12.4	13.5	15.9	15.3

Past domestic forecasts have been reasonable, but have under-predicted future energy needs at a rate of 1% per year into the future. The domestic forecast under-predicted energy consumption in 63 of the 65 cases analyzed. This under-prediction probably results from conservative assumptions for key economic variables and not from the model specification. Past forecasts for the general service sector have produced remarkably good results.

In the past, the industrial sector forecast has not performed well. The assumption of continued operation of the pulp and paper mills at Stephenville and Grand Falls was overly optimistic, causing problems that have affected the industrial forecast accuracy. The total Island energy forecast is prepared by summing the four sector forecasts, and consequently, the industrial forecast has affected the results for total Island energy requirements. Table 5 shows that all of the total Island energy forecast deviation can be associated with the overly optimistic industrial forecast. In fact, the Island energy requirements would be under-forecast if the industrial forecast was accurate.

Table 5: 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 (GWh)	-45	-72	-108	-130	-149	-163	-209	-260	-303	-366
General Service (GWh)	2	3	2	7	5	9	6	12	33	55
Industrial (GWh)	86	221	403	617	866	1,014	1,209	1,330	1,524	1,544
Other Loads (GWh)	-19	-26	-30	-40	-47	-52	-50	-47	-44	-58
Island Energy (GWh)	24	127	268	454	675	809	956	1,035	1,209	1,175

Table 6 measures forecast accuracy in terms of percentage of deviation from the actual peak load observed. The Newfoundland Peak demand regression equation accounts for 80% of the Interconnected Island demand and has performed extremely well. The Other peak forecast, which includes the peak demand associated with the Newfoundland and Labrador

Hydro (NLH) rural system, the NLH transmission system, and the industrial customers served by NLH, has not performed well. The Other peak forecast has been over-predicted as a result of a high industrial peak demand forecast. Since the Interconnected Island system peak demand forecast is prepared by summing the Newfoundland Power (NP) and the Other peak forecasts, the Interconnected Island peak forecast has also been affected by the high industrial peak demand forecast.

Table 6: 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	0.8	1.2	0.6	0.8	1.3	1.1	0.6	-0.2	0.2
Other Peak (%)	-4.5	-1.9	3.5	11.6	19.5	24.3	30.0	36.1	40.8	57.8
Island Peak (%)	0.3	0.1	1.6	2.9	4.7	6.1	7.1	7.8	7.9	11.1

Table 7 shows that the entire Interconnected Island peak forecast deviation can be associated with the high other peak demand forecast (rural, transmission & industrial).

Table 7: 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 (MW)	22	9	14	8	10	15	13	7	-2	3
Other Peak (MW)	-18	-8	9	37	63	78	96	113	125	166
Island Peak (MW)	4	0	24	44	73	93	109	120	122	169

2.1.4 Summary

Regression models for the domestic sector are well founded and produce reasonable results. The 2012 Interconnected Island option increased domestic load by 326 GWh by 2029. MHI considers the increase reasonable and an improvement over the 2010 Load Forecast because the latest forecast is based on more current information for the number of customers, the weather-adjusted average use, the marginal electricity price, and higher economic forecasts for personal disposable income and population.

Regression models for the general service sector are well founded and produce extremely good results. The 2012 Interconnected Island option decreased general service load by 156 GWh by 2029 due to lower levels of growth for commercial business investment. MHI considers the lower forecast for commercial business investment conservative, thus producing a conservative forecast for the general service sector.

The customer-specific methodology used to prepare the industrial forecast is reasonable. With the current industrial forecast, the 2012 Interconnected Island option forecast should perform well over the next 5 to 10 years. In the longer term, the potential for new industrial loads would increase the likelihood of under-predicting future industrial energy requirements. With potential reductions in industrial load, the 2012 Interconnected Island option forecast will over-predict energy requirements in the next five to ten years. In the longer term, the Corner Brook mill load could be replaced by new potential industrial loads. The 2012 industrial forecast does not include any potential increase for new industrial customers after the expansion to Vale is completed. The industrial forecast should contain some allocation for potential future industrial loads.

The total Island energy and peak requirements have been over-predicted as a result of pulp and paper closures that were not accounted for in the industrial forecast. Otherwise, the total Island energy and peak forecasts have performed extremely well. The primary concern is that the total Island energy and peak forecasts over the extrapolation period are too low. The extrapolated energy forecast is only 44% of the load expected over the next 20 years. The extrapolated peak forecast is only 48% of the load expected over the next 20 years. These reductions in future growth are significant and may be overly conservative. MHI notes that the Interconnected Island option is more resilient to large increases in load. This impact is further discussed in the CPW sensitivity analysis section 4.7.

MHI finds that the Interconnected Island Load Forecast is well founded and appropriate as an input into the Decision Gate 3 process.

Figure 6: Newfoundland and Labrador Generation and Transmission System Map

2.2 AC Integration Studies

As part of the Decision Gate 3 analysis, MHI has evaluated the ac integration studies considering the latest project definition with generation at the Muskrat Falls Generating Station using a point-to-point HVdc transmission system (Labrador-Island HVdc Link) with the inverter station at Soldiers Pond. With the documents Nalcor provided to MHI as part of the Decision Gate 3 review, the ac integration study review has now been completed.

A total of six studies were provided by Nalcor to MHI, and comprise the ac integration analysis for Muskrat Falls Generating Station and Labrador Island HVdc Transmission System. These studies are reviewed in detail in Sections 2.2.1 through to 2.2.6, and in Section 2.2.8.

2.2.1 Construction Power Study

The construction power study examines options to supply a maximum load of 12 MW, which is expected to be reached in 2015, at the Muskrat Falls construction site in Labrador. The SNC Lavalin study recommended the following:

- Replace the two existing 25/33/42 MVA, 230/138 kV transformers at Churchill Falls with a larger 125 MVA bank that has an on-load tap changer with a tap range of +5% to -15%. The two existing transformers and the gas turbine at Happy Valley are expected to remain connected for back-up supply during the construction period to cover for failure of this new transformer.
- Install a temporary 6 km 25 kV transmission line to connect the construction power site to the Muskrat Falls tap station. An additional 10 km 25 kV transmission line will be constructed to connect the construction site to the camp site.
- Use direct line to line motor starters for the large motors connected at the construction power site.
- Install six 3.6 MVAr capacitor banks at the Muskrat Falls tap station on the 25 kV bus. Each capacitor bank is equipped with a 0.1 mH series reactor.
- Install a new 30/40/50 MVA 138/25 kV transformer at the Muskrat Falls tap station. The size and impedance need to be checked to ensure motors at the construction power site will successfully start. The contractor is expected to supply a 25/0.6 kV transformer. The impedance and size of this transformer also need to be checked to ensure that the motors will successfully start.

The construction power supply study meets good utility practice. The above plan is robust and can supply up to 15 MW of peak load while meeting voltage criteria.

The original estimate of 6 MW used in 2010 was an old estimate calculated by Hatch Consultants in the early 1980s that did not include detailed engineering. Nalcor has good confidence in the 12 MW estimate as it was calculated by SNC Lavalin using recent information and detailed engineering calculations.

A 600 hp motor was considered to be the largest size that might be used at the construction site. Starting this motor resulted in a 4% voltage drop at the point of common coupling and 20% at the 600 V motor bus. This was considered acceptable in the report. Depending on the actual construction power motor load, such as larger motors, larger starting current, and frequent starts, there could be issues with voltage flicker or with motors tripping in the construction camp depending on their protection settings. Nalcor has indicated that the load estimate is mature including the number of large motors. The two 600 hp motors will at most start one or two times per day. The contractor will be made aware of the network limitations.

Only one 138/25 kV supply transformer is being proposed. In discussions with Nalcor, MHI indicated that it would be good utility practice to install two banks to ensure a reliable supply for the duration of the construction period. These two supply transformers should have staggered in-service dates to eliminate common mode failures during transport and installation. Nalcor indicated that a spare 138/25 kV transformer already exists at Happy Valley. This 28 MVA transformer has been a cold standby transformer at Happy Valley for the past twenty-five years. This transformer will be fully tested prior to the in-service date of the construction power substation and will be moved to Muskrat Falls if a failure occurs. In addition, two 2 MW diesel generators will be on-site for emergency power. ***Nalcor's construction power contingency plan is reasonable.***

The recommended capacitor bank size of 3.6 MVAr results in a 2.7% voltage change assuming maximum fault level. This voltage change is at the borderline of flicker visibility. If this were a permanent installation, normal utility practice would be to consider sizing the banks to avoid voltage flicker based on the minimum fault level. Adding a second transformer bank to improve supply reliability would help to reduce voltage flicker and lower the net impedance, which would improve the motor starting performance. Nalcor indicated preference to not move the bank unless absolutely necessary to minimize risk and cost. The long term plan is to use this transformer at Happy Valley. Customer loads connected to the 138 kV network are not sensitive to voltage flicker. ***Nalcor's capacitor bank plan is reasonable.***

If there are sources of harmonics on the 138 kV network, then the series impedance of the 138/25 kV transformer and capacitor banks should be sized to avoid a characteristic harmonic; especially the fifth harmonic. Transformer saturation due to elevated voltage levels is one common source of fifth harmonic. Nalcor indicated no known sources of harmonics and system voltages were typically less than 1.0 pu, which generally means the transformers are not saturated and not supplying fifth harmonic current. Therefore, series harmonic resonance issues are not expected.

2.2.2 Stability Studies

The stability studies in the SNC Lavalin report examined the impact of the 900 MW Labrador-Island Link HVdc system and the 500 MW Maritime Link on Newfoundland primarily, as well as the ac network between Churchill Falls and Muskrat Falls in Labrador. The Labrador-Island Link HVdc system is expected to be in service on July 1, 2017 and first power is expected at Muskrat Falls in July 2017 with each subsequent unit coming online every two months. For the purposes of the MHI Decision Gate 3 review, the Maritime Link is considered to be out of scope for this review.

The four-unit (4x206 MW, 0.9 pf) Muskrat Falls generation case was examined as Nalcor indicated this is the base plan that has been selected. Also, part of the 300 MW recall option from Churchill Falls is available to be used to supply Newfoundland load with a 90% capacity factor. As a result, the availability of generation at the rectifier of the Labrador-Island Link HVdc system is very high. Availability is only limited by the availability of the Labrador Island Link HVdc system.

Contingencies examined included permanent dc pole faults, temporary bipole faults and three-phase normal clearing ac transmission faults. The selection of faults generally conforms to NERC category B or n-1 disturbances.

For the Labrador-Island Link HVdc, it was recommended in the SNC Lavalin stability study to:

- Install line-commutated HVdc converters for the Labrador-Island Link HVdc system. The link should be designed with a 10-minute, 200% overload rating, and 150% continuous overload rating while in monopolar operation.
- Install three 150 MVAr high-inertia synchronous condensers. The study assumed that one of the three synchronous condensers are out for maintenance.
- Evaluate settings of under-frequency relays to ensure proper coordination, such as avoiding operation for high rate of change of frequency if not required.

The largest contingency of the existing Nalcor system is currently the loss of the entire Holyrood plant for a nearby three-phase fault. After 2021, it is proposed to retire Holyrood and only operate the plant as a synchronous condenser. Nalcor indicated in meetings that the Holyrood generators were tripping off due to the plant auxiliaries not having sufficient low voltage ride-through capability. With retirement of the boilers, Nalcor does not expect there to be any remaining plant auxiliaries that would impact the synchronous condensers and affect the operation of the HVdc link.

Nalcor provided information on generator under-frequency protection settings. The Holyrood units have a setting of 58.8 Hz and 45 seconds. For the cases simulated, the worst case was roughly 58.8 Hz for a temporary bipole block. There are no concerns with loss of additional generation with the Labrador-Island Link HVdc system as the minimum frequency is planned to remain above the first block of load shed trip point of 58.8 Hz with 0.1 second pickup time.

There could be advantages to specifying some short-term overload capability while in bipolar operation to cater for large generator outages on the Newfoundland network. Nalcor will be including this question in the converter request for proposal. Nalcor agrees that having access to additional spinning reserves from Labrador will have operational advantages. There are concerns with having the continuous nameplate rating of the link larger than 900 MW. Also, the proposed reactive power support may be insufficient unless the new 150 MVAr cold standby spare is made a hot standby.

Nalcor indicated they had upgraded some of their generating units with high-speed exciters that had power system stabilizers, and had plans to modernize the remaining units. However, all of the power system stabilizers on Newfoundland are turned off. The stability studies did not indicate any issues with poor damping of power oscillations and Nalcor indicated that no issues have been reported during real time operations. MHI recommends that a small signal stability study[2] be undertaken in the detailed design stage of the project to confirm that power system stabilizers are not needed or to determine the preferred settings for the power system stabilizers.

The stability study meets good utility practice.

Permanent Bipole Block

From an n-1 perspective, the Interconnected and Isolated Island options are different in terms of network impact following loss of the largest generator. No load-shedding is planned to occur following the loss of the largest generator in the Interconnected Island option. The Isolated Island option is a continuation of the status quo, which permits under-frequency load shed to occur. The Isolated Island option would require significant investment to match the

[2] The recommended study would be a small signal stability study. Such a study is able to determine which generators participate in power system oscillations and the best settings for damping low frequency (0.1 to 2 Hz) power system oscillations.

improved reliability of the Interconnected Island option. Additional inertia would be required as well as additional generation to supply spinning reserves.

From an n-2 perspective, the permanent bipole block results in a potential loss of up to 900 MW at the rectifier for the Interconnected Island option. A permanent bipole fault is a low probability event; however, it is a credible event. The Isolated Island option would have an n-2 generation loss between 340 MW (loss of two generators) and 520 MW (loss of the Holyrood plant). This is a major difference between the Isolated Island option and Interconnected Island options. There are no planning criteria in Newfoundland that requires prevention of instability for a permanent bipole fault. However, there is a requirement to minimize under-frequency load-shedding. It may be possible to separate Newfoundland into separate zones following a permanent bipole block to minimize the amount of load shed as well as to improve system restoration times. Nalcor indicated during the meeting that it was already investigating this as a potential mitigating measure.

The stability studies in the SNC Lavalin report examined the impact of the 900 MW Labrador-Island Link HVdc system on Newfoundland as well as the ac network between Churchill Falls and Muskrat Falls in Labrador. ***This study was performed according to good utility practice.***

2.2.3 Load Flow and Short-Circuit Studies

Short-circuit and load flow studies performed by SNC Lavalin were reviewed by MHI as part of the Decision Gate 3 review. ***Short circuit and load flow studies were performed according to good utility practice. No equipment concerns were noted in this study.***

From the SNC Lavalin study it was initially unclear whether the 138 kV and 69 kV networks are radial or networked. These networks were ignored in the study and assumed radial. Higher loading on the 230 kV network could impact underlying low voltage networks. In discussions with Nalcor, they indicated that there are three 138 kV transmission lines that are networked as follows:

- Holyrood to Western Avalon
- Sunnyside to Stony Brook
- Stony Brook to Deer Lake

Nalcor indicated that it does not currently have a spinning reserve criterion. For loss of the largest generator today, it relies on under-frequency load-shedding to prevent a widespread blackout. Under-frequency load shed is being used instead of spinning reserves. The same practice was applied to the analysis of load flow case of long-term future planning year. This case is set up without generation reserves, which means any generator outage results in load-shedding. Nalcor provided a guideline for Unit Maximum Loading that indicates the secure limit for the maximum plant as a function of system load. This guideline ensures that sufficient load is able to be dropped to prevent the frequency from falling below 58 Hz. Nalcor has made some investigations into adding spinning reserve to match the size of the largest unit loss and doubling the inertia of all existing units. This approach does not eliminate under-frequency load shed. The Interconnected Island option, with the addition of high-inertia synchronous condensers is able to improve this situation and avoid load-shedding for a single contingency.

From the SNC Lavalin report, and with clarifications by Nalcor, the equivalent short circuit ration (ESCR) at the Soldiers Pond was calculated with the assumption of synchronous condensers at Holyrood, and with none at Soldiers Pond.

2.2.4 HVdc System Modes of Operation and Control Strategies Study

The HVdc System Modes of Operation and Control Strategies Study conformed to good utility practice and properly identified the different configuration modes and operational modes.

Some items of a technical nature were raised during the meetings with Nalcor and it was determined that they were not material to the CPW analysis. For example, one item raised was that a pole block while in the loop power flow control mode could result in over-voltages requiring filter tripping. This contingency was not tested in the stability or power flow studies. MHI noted to Nalcor that it is recommended to simulate tripping of either pole and confirm the over-voltage impacts. Another item raised was whether there is a need to utilize overload capability while in this mode to increase the speed of ice melting, and whether there is concern if the import pole trips. The loop power flow control mode should automatically switch off if a pole trip occurs. Nalcor indicated that it will clarify this item during HVdc design studies. There should be no impact on cost or the CPW analysis. In the worst case, there would be a need for an addition of a filter overvoltage relay.

2.2.5 Harmonic Impedance Studies

The harmonic impedance of the ac network was calculated at Muskrat falls and at Soldiers Pond. This study was conducted according to good utility practice.

MHI recommends that the harmonic impedance study consider operation with three 150 MVAr synchronous condensers in operation as this may occur for high loads or outages of transmission lines near Soldiers Pond. Nalcor noted this recommendation and will recalculate the harmonic sectors for the Labrador-Island Link Request for Proposal.

A list of shunt reactors and capacitors near the converter station was not included in the harmonic impedance study to ensure appropriate sensitivity cases were completed. In discussions with Nalcor, they provided a list of capacitors and reactors up to four buses away and confirmed that sufficient variations were included in the harmonic study.

2.2.6 Reactive Power Studies

This SNC Lavalin report for Nalcor determined the steady-state reactive power capabilities of the ac network over the feasible operating voltage range of the HVdc converters. ***The report is written following on good utility practice.***

The inverter could be thought of as a generator interconnection and the inverter could be required to supply reactive power over the range 0.95 leading to 0.95 lagging at the point of interconnection over the complete operating voltage range between 0.95 and 1.05 per unit. Alternatively the link could be designed to operate at unity power factor or be self-sufficient in reactive power. Nalcor does not have a published grid code that defines the reactive power or voltage control requirements for new generator interconnections. Requirements are determined on a case-by-case basis depending on the size and location of the generator. For Muskrat Falls, no reactive power exchange was assumed available from Churchill Falls. With one unit out at Muskrat Falls, assuming filters were in-service supplying 25% of the reactive power of the rectifier, the remaining Muskrat Falls units were required to hold the 315 kV voltage at 1.02 pu. This required the units to be rated at 0.9 pf. At the inverter, assuming the filters provide 25% reactive support, the synchronous condensers are required to hold the voltage to 1.02 pu at maximum loading. ***This methodology is reasonable and consistent with the voltage and reactive power regulations used by the industry.***

2.2.7 Preliminary Transmission System Analysis – Muskrat Falls to Churchill Falls Transmission Voltage

The Preliminary Transmission System Analysis report examines the voltage options to interconnect the Muskrat Falls generating station to Churchill Falls. Four single-conductor 230 kV lines, three two-conductor 230-kV lines, and two two-conductor 315 kV or 345 kV lines were compared. Two 345 kV lines with 45 MVAr shunt reactors located at both sending and receiving ends were recommended. The 345 kV lines could also be built to 315 kV. **This report is in accordance with good utility practice and makes sound recommendations.**

According to Nalcor, the voltage level was selected at 315 kV for economic reasons. In addition, the 45 MVAr shunt reactors were removed in favour of using on-load tap changer capability and the reactive power capability of the Churchill Falls and Muskrat Falls generating stations.

MHI noted one concern; Nalcor intends to extend its normal practice on 230 kV lines in Newfoundland and implement single-pole trip and reclose on the new 315 kV transmission lines between Churchill Falls and Muskrat Falls. High voltage long lines greater than 300 kV quite often employ four-pole reactors to help improve the probability of extinguishing the secondary arc current, thus ensuring a successful reclose[3]. Without these reactors, a longer pole open dead time may be required or single-pole trip and reclose may need to be disabled. For the transfer levels studied, single-pole trip and reclose was not demonstrated as necessary to maintain stability. Nalcor noted this concern and will further investigate the need of single-pole trip and reclose and the feasibility of single-pole trip and reclose with and without four-pole reactors. There is some minimal risk that one or two four-pole reactors will need to be added with additional cost to each of the 315 kV lines, which will increase the cost by approximately $2 million per reactor installed for a maximum exposure of $8 million.

2.2.8 Labrador-Island HVdc Link and Island Interconnected System Reliability

The Labrador-Island HVdc Link and Island Interconnected System Reliability study compares the reliability of the Island Link HVdc to the existing system reliability. The impact of the Maritime link is quantified and the design criterion of the HVdc transmission line is discussed. ***This study meets good utility practice.***

With the Island link transmission line designed for a 1:50 return period, assuming a 14 day restoration time to fix transmission outages, results in a maximum 1% annual unserved energy. The report characterized the 1:50 return period being for ice-loading only but Nalcor clarified that this was for both wind and ice-loading.

A more accurate calculation method would have required the use of a probabilistic assessment tool. However, the purpose of the Nalcor study was to provide a simple quantitative comparison between the status quo and potential futures in terms of the impacts of major outages due to ice storms. The report fulfills this purpose.

2.2.9 Summary

The AC Integration Studies that were reviewed follow good utility practice and are adequate to define the minimum transmission facilities needed to:

- Supply the expected maximum construction power load of 12 MW at Muskrat Falls,

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[3] IEEE Committee Report "Single Phase Tripping and Auto Reclosing of transmission Lines", pp. 185, Jan. 1992. In table III of the IEEE Committee report, they note for 345 kV lines greater than 140 miles, additional measures must be undertaken to reduce the secondary arc current.

- Interconnect four 206 MW Generating units at Muskrat Falls, and
- Deliver the output from approximately 900 MW of generation in Labrador to Newfoundland load.

There is a remote possibility that up to four 45 MVAr 315 kV four-pole shunt reactors may be needed to permit successful single pole tripping and reclosing on the new 315 kV lines between Churchill Falls and Muskrat Falls. The maximum cost impact is $8 million. However, it is possible to avoid this cost by potentially disabling single pole trip and reclose.

MHI recommends:

Harmonic impedance sector calculations include cases where all three synchronous condensers are in operation for both system intact conditions and 230 kV ac transmission line prior outages. The study can be performed in the detailed design stage to provide the HVdc suppliers adequate information to design the ac filters.

Further work should be conducted to design a special protection scheme that will balance available generation with load following a permanent bipole outage on the Labrador Island HVdc Link. The 230 kV transmission system on the Island can be configured to trip specific transmission lines with the use of an appropriate under frequency or rate of change of frequency relay, or direct tripping signal from the HVdc converter station at Soldiers Pond to balance load with generation. This study is not critical to Decision Gate 3 and can be completed prior to the in-service date of the Labrador-Island Link.

A power system stabilizer study should be conducted in the detailed design stage to determine appropriate settings for the Muskrat Falls Generating Station as well as for generators and synchronous condensers in Newfoundland. The study is not required for Decision Gate 3 but good utility practice dictates that it be performed as part of the detailed design.

The result of the six studies conducted by SNC Lavalin for ac integration demonstrates that Nalcor is in compliance with good utility practice. There is an opportunity during detailed design to optimize final configurations that may enhance the system reliability.

2.3 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 Decision Gate 3 review of the two options. This review was carried out by HVdc experts on staff at MHI through meetings with Nalcor and reviews of a number of confidential documents provided by Nalcor.

2.3.1 HVdc Configurations

The system single line diagrams were reviewed for the HVdc converter stations (dc yard) at both terminals with electrode sites, the new 315 kV ac switching station at Muskrat Falls, the ac system extension at Churchill Fall 735 kV / 315 kV switching station, and the new 230 kV ac station at Soldiers Pond. The dc and ac yard layouts as shown in the single line diagrams follow good utility practice and the identified system upgrades are well supported by the study reports described in AC Integration Study Review Sections 2.2.2, 2.2.4, and 2.2.6. The planned transmission outlet facilities at Muskrat Fall and Soldiers Pond are adequate for the proposed HVdc Link rating. Three high-inertia synchronous condensers are planned to strengthen the system and assist in voltage and frequency control.

2.3.2 Reliability and Availability Assessment

The Reliability & Availability Assessment report presents the results of the reliability and availability analysis carried out to determine the expected reliability performance of the proposed Labrador-Island Link HVdc system. The Reliability and Availability performance indices for key system components including the converter stations, the HVdc transmission line from Muskrat Falls to Soldiers Pond, the submarine cables, the electrode lines and the composite reliability performance of the complete Labrador-Island Link HVdc system were derived and considered to be in the reliability performance range of the HVdc schemes in-operation today. The recommendations on provision of spare equipment such as converter transformers and smoothing reactors follow good utility practice.

The Nalcor study determined that the repair time of the HVdc transmission line failure has significant impact on the availability of the island HVdc link. Line design enhancement such as anti-cascading towers and a good emergency response plan are recommended for further evaluation as part of the detailed design stage post Decision Gate 3. Special care shall also be paid to the electrode line reliability, such as insulation coordination and arc extinguishing capability, due to its unique overload operation mode under pole outages and extreme long distance.

The electrode line and electrode section is dealt with in a limited fashion and requires more attention as this element is critical for the overload capability during mono-polar operation. Because of the long-distance of the electrode line on the Labrador side and the fact that during normal operation there is virtually no voltage or current (just the bipolar unbalance current), detecting the soundness of the electrode line is very difficult. The exact design would be part of the detailed engineering provided by the supplier. Investigation into fault detection and locating systems such as Pulse Echo systems for the electrode lines is suggested by MHI. Addition of this item would not materially impact the CPW of the overall project.

2.3.3 HVdc Master Schedule

The HVdc system master scheduling documents provided by Nalcor to MHI outline the schedules for procurement, installation, and commissioning of the HVdc converter stations and related components. The project schedules and execution times including engineering, procurement, and constructions are comparable to similar HVdc projects.

2.3.4 HVdc Cost Estimates

Master cost estimates provided by Nalcor to MHI for the HVdc converter stations, ac switchyards, synchronous condensers, and electrode sites were examined as part of the Decision Gate 3 review.

The capital cost estimate includes the system upgrades at the HVdc converter stations (both ac and dc yards) and the island system enhancement as well as replacement of high voltage breakers. Two shoreline electrodes and associated electrode lines are included in this estimate. The first electrode line from the Muskrat Falls converter station has a significant length of about 400 km and most electrode line will be mounted on the same HVdc overhead tower. The second electrode line will emanate from Soldiers Pond approximately 10 km to the electrode site near Dowden's Point in Conception Bay. The estimates on synchronous condensers are somewhat low based on MHI's experience on other projects, but are within the bands of cost estimate variability. The costs for Nalcor's synchronous condensers have been estimated from suppliers' quotations.

The capability of maintaining full HVdc power rating while losing one ac filter branch element was verbally discussed with Nalcor as MHI noted that this information was not included in the Short Form Specification sent to the suppliers. Nalcor has confirmed that each filter bank will be made up of several branch filters and will have redundancy at the branch filter level such that if one branch fails, or is disconnected for maintenance, there will be no need to de-rate the power transfer.

Sufficient contingency has been allocated to this portion of the project to offset any unforeseen project risks.

MHI finds that the estimates are reasonable as inputs to the Decision Gate 3 process and CPW analysis.

System Study Reports

The scope of work in the Nalcor study reports included power flow and short circuit analysis, harmonic study, reactive power study, transient stability analysis, HVdc control strategy and HVdc modes of operations.

The Load Flow and Short Circuit Studies and the Reactive Power Studies provide by Nalcor to MHI have determined the short circuit levels (fault levels) at converter stations, power dispatches under various load flow scenarios, and reactive power requirements for the proposed Labrador-Island Link HVdc system. The proposed system upgrades at Muskrat Falls and Soldiers Pond are adequate for the HVdc operating modes considered and the overload requirement. The ESCR requirements are met at both converter terminals with the proposed system upgrades and the HVdc system is expected to provide acceptable performance based on industry experience. The harmonic impedance study provides preliminary information for the filter designs with no adverse low-frequency system resonance identified.

Detailed HVdc performance under various contingencies is evaluated in the stability study report provided by Nalcor. It is worthy to note that Nalcor has stated that one of the main system development criteria is to achieve the same or better reliability than today's system considering its unique island electrical system configuration. The study results demonstrated the acceptable HVdc system responses of the proposed HVdc link following various ac and dc contingencies. Two 150 MVAr high-inertia synchronous condensers plus one spare are required based on system stability requirements.

The HVdc configurations, operation modes, control hierarchy and strategies, and communication requirements were presented in the study report provided by Nalcor to MHI. The basic philosophy outlined in this report conforms to good industry practice. The report stated that the final implementation requirements were to be developed and presented as part of the Technical Specifications. During islanded operation (i.e. when the Labrador Island HVdc Link is forced out of service), the impact of frequency excursions on control strategy will need to be evaluated during recovery operations. However, no implications on the additional costs are expected.

Short Form Technical Specification

Lower Churchill Project Short Form Technical Specification dated October 13, 2011 provided by Nalcor was reviewed as part of the Decision Gate 3 review by MHI. This document was provided to three suppliers to obtain cost estimates for the HVdc converter stations: ABB, Siemens and Alstom Grid. The Specification forms the basis for the costs estimates received from the suppliers. The typical practice was to discard the lowest estimate and average the two highest for budget preparation. This philosophy was carried forward in all cost estimates prepared for Decision Gate 3 where applicable.

There is a possibility of additional costs, depending on what assumptions were made by the suppliers in the preparation of their estimates. Given that Nalcor has indicated that they have used the average of the two highest estimates of three submitted, which were both relatively equal, MHI believes that this approach is reasonable when estimating budgetary costs.

2.3.5 Summary

MHI through its review notes the following important points:

- The study determined that the repair time of the HVdc transmission line failure has significant impact on the availability of the Labrador-Island Link HVdc system. Line design enhancements such as anti-cascading towers as planned by Nalcor will improve reliability. Development of a good emergency response plan is recommended by MHI as part of the operational stage of the project post Decision Gate 3. Nalcor has committed to have this emergency response plan developed prior to in-service.
- Due to the long-distance of the electrode line on the Labrador side, and the fact that during normal operation there is virtually no voltage or current in the electrode line, monitoring of the soundness of the electrode line is very difficult. Investigation into fault detection and location systems such as Pulse Echo systems for the electrode lines is recommended during the detailed design phase post Decision Gate 3. Addition of these detection systems is expected to have a minimal cost impact on the CPW analysis.
- The cost estimates for the synchronous condensers appear low when compared to other projects in Canada; however Nalcor has secured these costs directly from manufacturers. The cost estimates are within the bands of cost estimate variability for an AACE Class 3 estimate range.

Overall the project as indicated by Nalcor in documents provided appears reasonable. MHI has made some recommendations as outlined above that may provide improvements to the project.

The system upgrades identified in the single line diagrams for HVdc converter stations, ac switchyards, and electrodes are well supported by the study reports provided to MHI by Nalcor and are reasonable as inputs to the Decision Gate 3 CPW analysis.

2.4 HVdc Transmission Line, Electrodes and Collector System

The purpose of this section is to conduct a high level review of the HVdc lines, the electrode sites, and the high voltage ac (HVac) collector transmission system Nalcor proposed at Decision Gate 3.

Cost estimates, construction schedules, and the design methodology undertaken by Nalcor in preparation for Decision Gate 3 were examined and an assessment made of the reasonableness as inputs to a CPW analysis.

2.4.1 Schedule

Nalcor's proposed schedule for the HVdc and HVac line designs, procurement, and construction were reviewed through a series of interviews with key Nalcor personnel. A high level schedule for the existing project scope was requested by MHI and provided by Nalcor for examination.

At this time, detailed design of the transmission line structures is under way, and testing of critical line structures scheduled later this year. Nalcor has planned for detailed design right through the entire construction phase in the schedule. This is a prudent industry practice to support construction on large transmission projects with changing terrain necessitating field-specific design solutions.

Procurement activities have been staged in the first quarter of 2012. MHI understands much work has been done to verify pricing and supply of the various transmission line materials pending official Decision Gate 3 project sanction. To date, a total of 21 material procurement management packages are being prepared to fulfill the transmission requirements. To maintain the project construction schedule as planned, the majority of material contracts for long lead-time items such as towers, insulators, and conductors should be awarded by the end of 2012 for a fall 2013 or early 2014 construction start.

The construction window for all high voltage transmission line construction activities for the project complex has been allocated approximately four years with clearing activities starting in the second quarter of 2013. MHI finds the schedule to be reasonable and achievable provided construction work and equipment access is possible during all four construction seasons.

2.4.2 Cost Estimate Evaluation

Nalcor provided MHI with a detailed report on the Decision Gate 3 transmission line cost elements broken down into the key components described as: Construction, Supply, Geotechnical Exploration, and Right of way clearing.

Nalcor described the methodology in preparing the estimate and MHI considers that it accurately reflects the costs forecasted for the design and construction of the transmission lines.

The Decision Gate 3 estimate is based upon the following contributory factors:

- Costing from suppliers for detailed material breakdowns and known bulk quantities such as number of towers, insulators, and hardware
- Transmission contractor budgetary feedback based upon the proposed schedule and construction methodology and timelines
- Engineering concepts that are virtually complete, and scope changes tracked and identified
- Labour unit costing assuming a negotiated master labour agreement, equipment and commodity rates are identified
- Productivity factors for labor, equipment, while factoring in seasonal impacts.

Comparing the Decision Gate 3 cost estimate evaluated on a cost-per-line-km basis with other similar projects under way in Canada, MHI finds the Muskrat Falls transmission line component costs are at a reasonable level and accuracy for this stage of the estimate. ***The costs for the transmission lines are within an AACE Class 3 estimate accuracy congruent to the requirements of Decision Gate 3.***

2.4.3 Risk Assessment

Nalcor has identified the key areas of project risk in its project management strategy. At the current stage of project progress, the majority of major engineering decisions affecting transmission line design and construction have been made and costs estimated for Decision Gate 3. Nalcor has displayed appropriate controls and signing authority managing scope changes with the Transmission Deviation Alerts and the Change Notice document MHI reviewed.

With the level of engineering complete to date and the tracking system in place, the probability of major scope changes to the design affecting cost and schedule is assessed as very low. At this stage minor route changes will not affect cost or schedule significantly.

Material costing has been calculated with estimated line quantities at current market values and as such is likely to only vary with the final tower optimization quantities. These variations should not be significant from the quantities currently estimated.

At this stage, the major risks to be addressed for the transmission line complex remain as contractor cost, labour availability and productivity. Nalcor has identified this as a major risk and has identified mitigation strategies to attract skilled labour back into the province through a master labour agreement, training, and other self-development programs.

2.4.4 Assessment of Line Routes

MHI has reviewed the line route corridor provided in documents by Nalcor in topographical mapping format. The corridors MHI reviewed are the 2 km wide general study corridor running from Muskrat Falls across the Strait of Belle Isle to the Soldiers Pond Converter Station, and the 60-metre-wide proposed transmission line alignment contained within it. Work acquiring property and easements for the alignment is currently underway. MHI's assessment will be limited to the route corridor as it has been defined to date.

HVdc Transmission Line Route

The route selected for the HVdc line is optimal considering the primary criteria required for an efficient bulk point-to-point transmission line. The line has been designed to minimize the distance between the source of generation at Muskrat Falls and the load centre at Soldier's Pond, minimizing angle locations where possible. The route navigates the more difficult areas of Labrador, by-passing the numerous large lakes, ponds, and swampy terrain with a minimal number of line angles. All water crossings appear achievable with minimal custom site designs typified as shown in Figure 7.

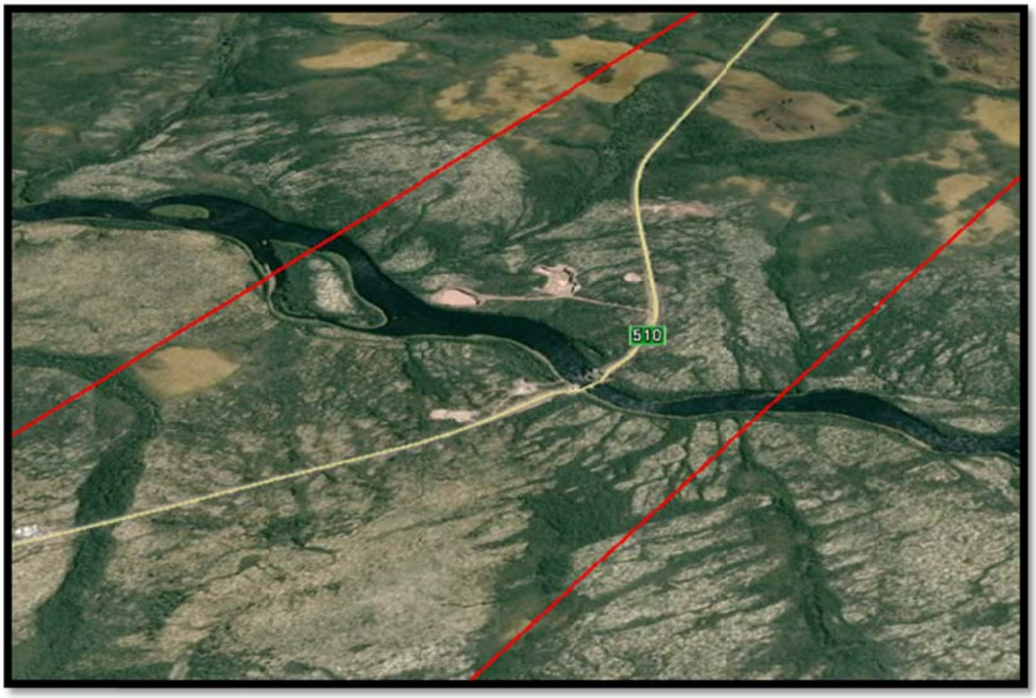


Figure 7: Typical river and highway crossings along the HVdc transmission line route. Crossing spans are achievable with the current transmission line design parameters.

The route proceeds as directly as possible through the Long Range Mountain Ridge before it turns east heading across the Newfoundland Island to the Soldiers Pond Converter Station.

Portions of the route are adjacent to major roads such as the Trans-Canada and Trans-Labrador highways. This will help facilitate access to clearing, construction of the line, maintenance, and with planning an emergency response scenario. A review of the corridor displayed numerous access trails which should enable reasonable access to the line in most seasons.

The entire transmission line corridor through Labrador and the Newfoundland Island is selected and under review for the environmental and licensing process. ***MHI finds the route was selected with due diligence and appears to be well suited for its purpose.***

AC Transmission Line Routing

The routing for the two 315 kV ac lines connecting Churchill Falls to Muskrat falls essentially follows the corridor of existing 138 kV transmission line TL 240. The corridor is well established and will be widened to an appropriate width to contain the additional two lines. MHI reviewed the transmission line corridor and does not foresee any difficulties with this planned corridor addition. Nalcor still needs to obtain appropriate approvals and easements.

Electrode Line Routing

Detailed routing for the small lengths of electrode line carried on single wood pole structures to the Labrador (25 km) and Newfoundland (15 km) Electrode sites were not reviewed in detail as these short lengths of electrode line will have minimal impact to overall project costs and the right of way.

2.4.5 Structure Families

MHI reviewed Nalcor's proposed structure families for the new transmission lines in meetings with Nalcor and reviewed formal and informal printed documentation from design files. Composition of final tower design and fabrication drawings is in progress and at an acceptable level of completion for this stage of the project.

Nalcor's design philosophy used to determine the structure families for the ac and dc transmission lines follows an industry-accepted practice of apportioning out structures into "families" classified by their function along the transmission line. Structure families proposed in the designs include tangent suspension structures, various degrees of angle structures, heavy angle, and termination structures used to sectionalize the line.

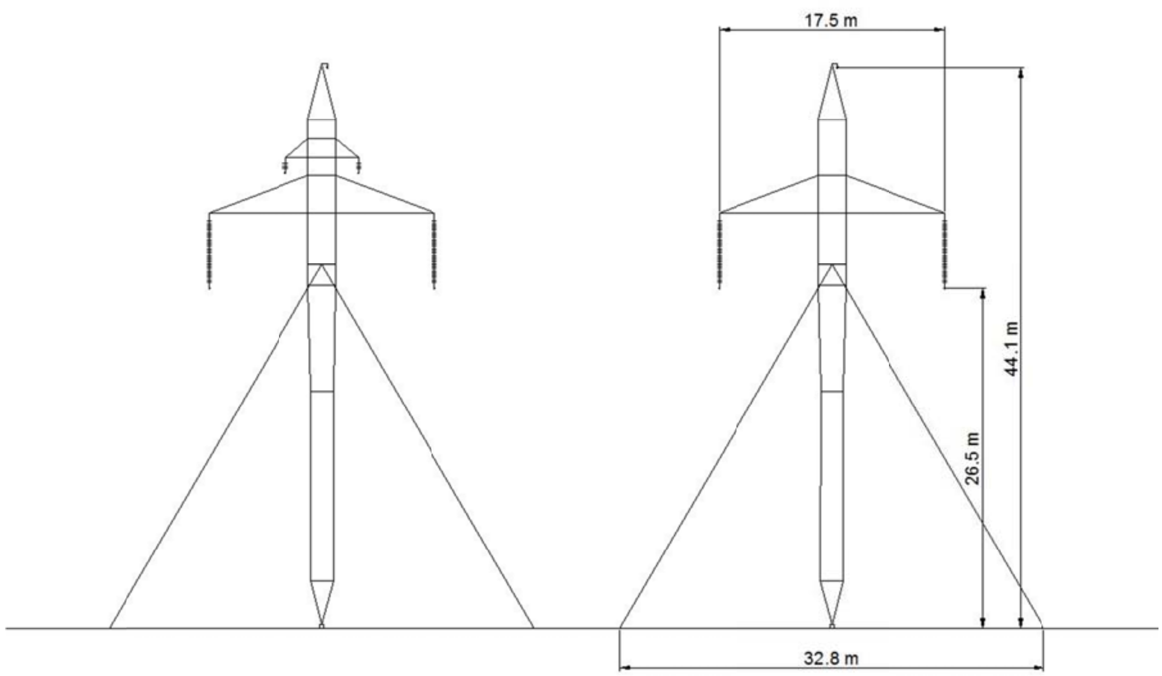
The tangent suspension towers Nalcor has selected for both ac and dc systems are composed of guyed lattice steel mast-type structures modifiable by height extensions to maximize tower utilization in the rolling terrain common along the entire corridor. These types of structures are the most economical choice given the variety of geophysical soil conditions, terrain to be crossed, and remoteness of the route selected. Use of these structure types is common throughout the industry, and there are many other examples of these towers successfully installed throughout North America.

Other structures proposed are lattice steel self-supporting towers typically positioned at angle locations and other sections in the line for termination purposes or boundaries between weather-loading zones. Critical to the performance and maintenance of self-supporting structures are suitable foundations for the terrain type. Nalcor has identified these tower locations for detailed geotechnical exploration which is acceptable methodology for structures of these types. Given the information provided by Nalcor, MHI finds that the selection made for structure families and types to be reasonable.

HVdc Transmission Line Structure Family

MHI reviewed Nalcor's design specification documents which outlined in detail the approach determining the tower design and geometry, span spacing, load capacity, and other detailed engineering criteria pertinent to the proposed HVdc transmission system. From extensive meteorological research, Nalcor determined that the transmission line would require 11 unique weather zones, with a number of subzones, to adequately model the ice-and-wind loading on line structures.

Engineering work is in progress to complete the detailed design for the HVdc line. Nalcor has defined 12 structure families, with a total of 25 structure types, required to economically construct the line. Wherever possible, an effort was made to use common structures in the various loading zones in an effort to minimize the number of unique, custom structures which mitigates design and construction cost.



HVdc Segment 1 (with electrode) HVdc Segment 2 (without electrode)

Figure 8: Typical HVdc Transmission Guyed Tangent Structures which comprise approximately 85% of the towers in the Labrador-Island HVdc transmission line

Nalcor's design controlled the structure loading from the various ice-and-wind loading combinations by reducing or increasing the ruling span in the 11 weather-zone regions. Generally, as the loading increased, the design ruling span and conductor tension was reduced. This is an acceptable approach to controlling the structure size and weight, and ultimately construction and logistics costs.

MHI has reviewed the various ice-and-wind loading cases and required structure families and has determined that Nalcor's design approach, given the severity and wide range of weather cases found along the transmission line route, is a reasonable and cost-effective methodology.

AC Transmission Line Structure Family

MHI reviewed Nalcor's design specification documents which outlined in detail the approach determining the tower design and geometry, span spacing, load capacity, and other detailed engineering criteria pertinent to the proposed HVac transmission system connecting the Churchill Falls Switching Station to the Muskrat Falls Switching Station.

Two 315 kV ac lines are proposed, and Nalcor has advised that only one structure family with five different tower types is required for the route. The structure family is composed of guyed steel lattice structures with self-supporting angle and termination structures. As this line is predominantly in one weather-loading zone, MHI concurs with Nalcor's decision in selecting this structure family design.

Electrode Line

For reasons of life-cycle economics and reliability, the electrode line on the Labrador portion of the HVdc line was recently moved from individual wood pole structures located along the right-of-way edge to a position on the HVdc line structures from Muskrat Falls to Forteau point. MHI finds it is a prudent decision to consolidate the HVdc pole and electrode conductors onto one supporting structure in the Labrador transmission line section. There are considerable cost savings in construction effort, material, and the long-term maintenance required of wood pole structures.

From Forteau Point to the Labrador Electrode site at L'Anse-au-Diable, and from the Soldiers Pond Converter Station to the Dowden Point electrode site, the electrode line is suspended on standard wood pole structures of similar size to a distribution pole system. MHI concurs with the design methodology that Nalcor selected for the electrode line system.

2.4.6 Assessment of Transmission Line Reliability

Nalcor made several prudent decisions regarding the detailed transmission line design to reduce the probability of an outage, and failure or progression of failures in line structures with the intent to increase the line's overall reliability. The following salient points highlight these decisions:

- The guyed structure configuration will naturally resist failure from cascading events and is more stable in the rugged terrain found along the route
- Provision of special anti-cascade towers every 10 to 20 structures to contain and isolate failures and prevent them from impacting large sections of line
- In sections of the transmission line with the most severe combined ice-and-wind loading, the spans have been shortened appropriately to reduce structure loading to manageable levels
- Selection of a single large conductor in place of a multi-bundled conductor arrangement. This prevents ice accumulations bridging across sub-conductors to form large shapes which would transfer high wind loads to structures. Nalcor has selected a large 3640 MCM 91-Strand all-aluminum conductor (AAC) family for the entire transmission line, and is currently investigating the use of high-strength aluminum alloy conductors of identical size for use in the extreme ice regions required to maintain reliability.
- Insulator suppliers were limited only to vendors with international reputations for quality, operational reliability, and who have established distribution networks that will allow them to comply with delivery schedules.
- Due to the effect the rolling terrain has on tower locations and optimization, the average tower strength utilization on tangent towers will be somewhat less than the designed capacity, with utilization possibly averaging between 75% and 85% of the ultimate strength. This has the effect of increasing tower resistance and stability during extreme weather events, thus increasing overall reliability.
- Selection of the final alignment within the route corridor attempted to minimize exposure to the extreme climatic-loading regions such as Long Range Mountain Ridge, and to avoid areas where the terrain acts to accelerate and funnel the wind.
- Tower window dimensions and spans are designed to comply with the most up-to-date theory predicting conductor motion in extreme wind and ice events. This will reduce or eliminate outages during these events, increasing the overall transmission line reliability.
- Tower prototype testing on the most common line structures to affirm capacity and behavior under loading is scheduled for late 2012.

MHI finds Nalcor has completed a thorough assessment of the various climatic regions impacting the ±350 kV HVdc line from Muskrat Falls to the Soldiers Pond transmission line route. In documents provided by Nalcor to MHI, the meteorological research determined that 11 zones along the route corridor with a number of subzones, each with a unique zone-specific climatic loading is required to reliably predict climatic loading to the transmission line.

The climatic loadings for each line section were selected based on Nalcor's past research studies and statistical analysis of the climate data. Extreme values based upon historical data and observations on ice accumulation and wind speed were implemented in the line regions through the Long Range Mountains and other regions in Labrador. This follows the recommendations of CAN/CSA A.7.2 where designers are cautioned to investigate and design for areas with localized higher icing and/or wind forces. It is MHI's opinion Nalcor undertook appropriate due diligence selecting the weather loads for this transmission line.

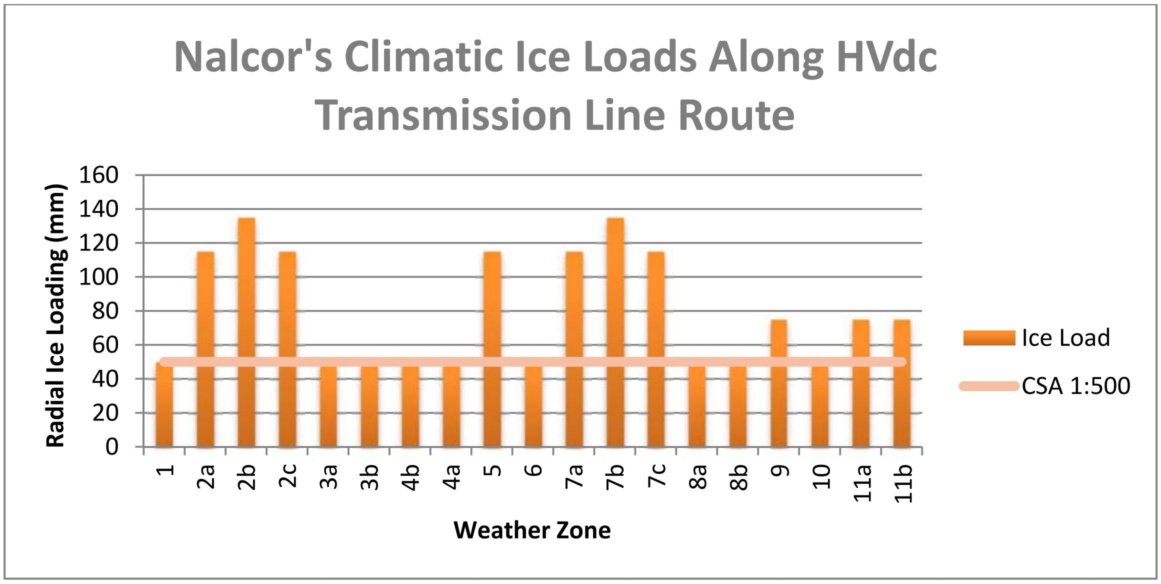


Figure 9: Climatic Ice Loads along the HVdc Transmission Line Route compared to the CSA Standard 1:500-year return period limit

Nalcor's research studies to define the climatic loadings along the transmission line route were based on 50 years of data, as outlined in the document "Muskrat Falls Project – Exhibit 97, Appendix A Revision 1". The climatic loadings for each line section are approximately equivalent to the climatic loadings calculated assuming a Canadian Standards Association (CSA) 1:500-year return period.

MHI notes that CAN/CSA C22.3 suggests a greater reliability of design to 1:150-year or 1:500-year return periods for lines of voltages greater than 230 kV which are deemed of critical importance to the electrical system. It is MHI's opinion the ±350 kVdc and 315 kV ac lines proposed for the Lower Churchill Project be classified in a critical importance category due to their operating voltage and role in Nalcor's long term strategic plan for its transmission system and be designed to a reliability return period greater than 1:50 years.

Nalcor, as part of the detailed design post Decision Gate 3, is aware that increased reliability is needed in the Long Range Mountains and other regions in Labrador subject to extreme wind and icing conditions and has taken actions to upgrade portions of the line. Nalcor, from its own analysis of the climatic loading study and information acquired from experience in the region, has specified a transmission line design criteria that exceeds the ice loading requirements experienced in Newfoundland and Labrador over the past 50 years.

2.4.7 Emergency Response Plan

Emergency response plans for an HVdc outage scenario will be instituted once the line is placed into service and is not normally part of the Decision Gate 3 review process. Informal discussions with key Nalcor staff were held on the topic to determine what, if any formalized emergency restoration is planned. Emergency response times to restore the line to normal operating conditions are very difficult to predict due to the remoteness of the transmission line and levels of failure possible. Outage periods up to one month or greater in remote line sections are possible. The emergency response plan needs to consider the availably of alternate generation in addition to the potential duration and extent of an HVdc transmission line outage. Nalcor acknowledges that an emergency response plan is necessary and will undertake the development of one prior to in-service.

The items addressed for possible follow-up in a restoration plan may include:

- Purchase and strategic storage of material caches, spare all-terrain equipment to access remote sites. Material for caching may be purchased with the primary material orders to take advantage of bulk costing.
- Development of an access and restoration trail-way system. This should be done during primary construction.
- Design of temporary emergency structures and anchoring devices which may be flown in to remote tower sites.
- Mutual aid agreements with neighbouring utilities.

2.4.8 Summary

The following is a summary of the key findings from the review of the information gathered and interviews held with the Nalcor project team.

The Nalcor project management team is utilizing an experienced consultancy firm to prepare the detailed design, material, and construction cost estimate taken forward to Decision Gate 3. Nalcor is utilizing professional staff with engineering and project management backgrounds to manage, track, and direct the consultant using accepted project management practices.

The design and construction schedule proposed by Nalcor is achievable provided there are no major changes to the project scope, unusual weather encountered during construction seasons, and adequate contractors are retained with resources available.

In its evaluation of the conductor optimization and selection report prepared by SNC Lavalin, MHI noted to Nalcor that the report did not examine in sufficient detail the reliability issues of the recommended conductor operating in the severe icing regions through the Long Range Mountains. Nalcor has indicated a study of this technical issue is underway to examine the use of extra high-strength aluminum alloy conductors in these regions. The approximate 20% cost premium for these conductors is not included in the Decision Gate 3 estimate, but since the severe icing regions represent only 15% of the transmission line length, the impact to the total project budget if the alloy conductor is implemented is negligible.

In MHI's opinion, Nalcor has undertaken a reasonable approach to design the transmission line to withstand the many unique and severe climatic loading regions along its line length. MHI continues to support selecting a 1:150 year climatic return period due to the criticality of the HVdc transmission line to the Newfoundland/Labrador electrical system.

MHI recommends that Nalcor develop a transmission line emergency response restoration plan prior to in-service which includes consideration of access routes, material caches and equipment which can be mobilized in an emergency.

The transmission line structures and routes selected for all transmission facilities are cost-effective considering the terrain, route, and climatic loading expected. From the review of the written documentation provided, design methodology, and information recorded in the Nalcor staff interviews, MHI has found that the Decision Gate 3 estimates for all transmission facilities were prepared in accordance with good utility practice and within an AACE International Class 3 level accuracy range.

2.5 Strait of Belle Isle Marine Crossing

The configuration of the Strait of Belle Isle (SOBI) cable crossing has not changed significantly from prior studies.

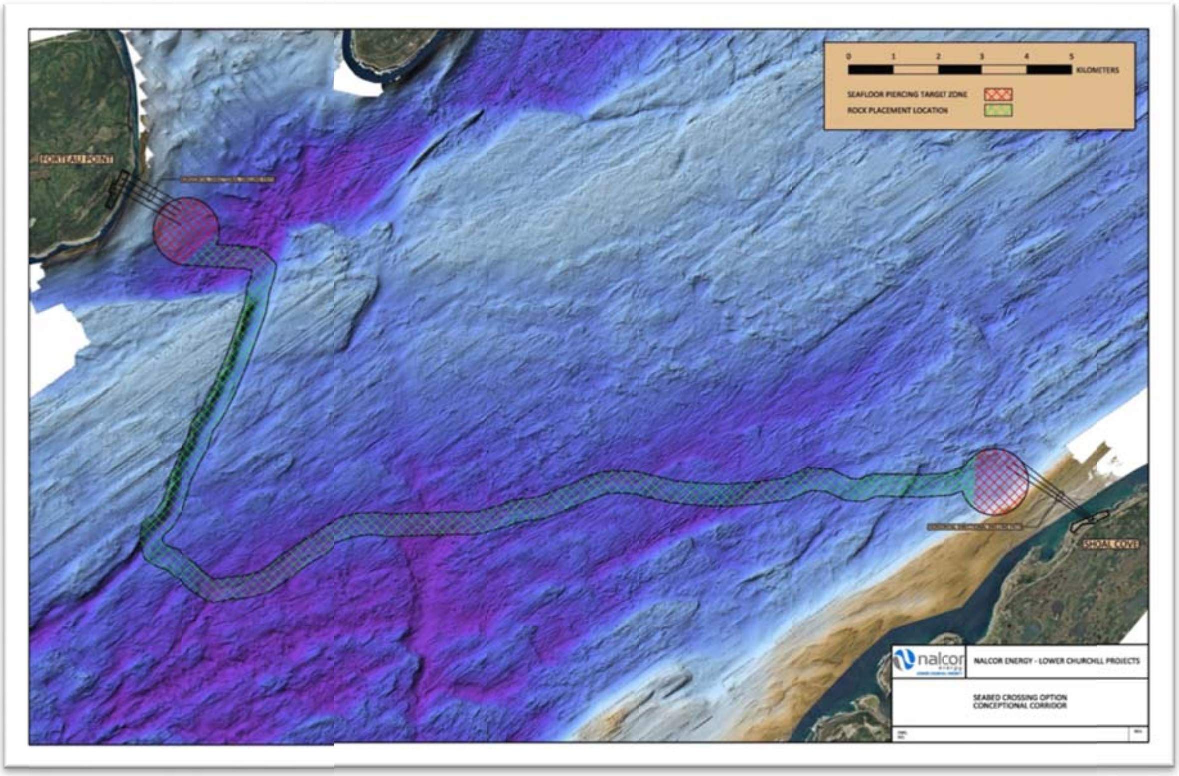


Figure 10: Strait of Belle Isle Marine Crossing Location

Further refinement of the route is being investigated to firm up the shore approaches, the horizontal directional drilling (HDD) techniques, the sea floor routing, the cable-laying technology, and the rock berm placement. There are ongoing studies of the currents and tides in the Strait, and continued surveillance of iceberg movements and roll rates in the vicinity. An observation tower has been erected to track movement of icebergs through the Strait and record actual roll rates. The status of these works was reviewed during meetings with Nalcor for this segment of the project.

2.5.1 Decision Gate 3 Activities

Significantly more knowledge has been gleaned in all aspects of the marine crossing project. There have been ongoing discussions with the potential cable suppliers, the cable has been tendered and a contract award is imminent. A decision has been made to embed fibre-optic cable for communications into the submarine cable, which increases the cost of the cable but results in an overall net reduction in this segment of the project.

Considerable work has also been done with cable-laying contractors, rock berm contractors and a test HDD bore hole was drilled from the Shoal Cove Landing site on Newfoundland for a distance of approximately 1,500 m. Drill rates were assessed during this test and were slightly longer than previous estimates. Some problems were encountered with fractured rock but grouting procedures proved workable. The bore hole was reamed out to 14 in. in some areas and 24 in. in others without any significant problems. These diameters are a specified requirement for the steel liner to be placed. It may be possible that the other two bore holes may be drilled at a lower depth to prevent the intersection of the fractured rock and subsequent requirement for grouting. Although the bore hole was not completed to the subsea floor, it is very likely that drilling re-entry will be done and the test hole used for one of the three cables.

From discussions with potential installers, it is expected that the laying of the cable on the sea bed can be completed in approximately 45 days. Iceberg flows typically prevent a start-up of work in the Strait until at least June 1. The work season in the area usually extends to late October so there appears to be ample time to complete this work in one summer season, rather than the two-year program originally envisioned.

If in fact the project is completed and the HVdc lines and converter stations are in service by the fall of 2016, it may be possible to transmit power imported from the market with significant savings in fossil fuels at the Holyrood Generation Station.

It has been determined that all of the cables can be placed on the laying vessel, reducing the time required to reload during the installation exercise. It is expected that the cable can be floated at the Labrador side and a joint made on board the laying ship with the cable from the shore approach.

Discussions with potential rock berm suppliers are underway to optimize the design. Information has also been made available from suppliers on a new technique for removing the rock from the berm should it be necessary to facilitate a repair to the cable. This new method would involve vacuuming the rock off the berm, allowing removal of rock up to 16 inches in diameter. Several qualified Canadian contractors have been trained in the use of this equipment.

2.5.2 Schedule and Estimates

The cable for the 32 km crossing has been tendered and three bids have been received. Suppliers have quoted firm prices in Canadian dollars for cable delivery in 2015-2016. The inclusion of the fibre-optic cable would result in a reduction in costs while improving reliability rather than relying on line-of-site communication towers on either side of the Strait.

The conductor was originally specified at 320 kV and has subsequently been upgraded to 350 kV. The increase in operating voltage will result in minimizing line losses and improve the business case for the higher voltage cable. The larger conductor will also support an increased pull-in-load to better facilitate installation.

The land-trenching costs are likely to be somewhat higher than previous estimates based upon the observed rate of progress on the test bore hole and unit costs for construction.

There are also several opportunities to reduce costs from previous estimates. There may be potential to shorten the crossing distance following a more detailed engineering design. A request for proposal for the rock berm is scheduled to be issued at the end of summer 2012 which will firm up both the quantity and cost of rock to be placed.

It may also be possible to reduce the planned size of the HDD bore hole. Any reduction in size will increase drill rates, shrink the size of the steel liner and therefore lower the overall cost of the SOBI crossing. The SOBI cable crossing has been adequately redefined in Decision Gate 3 and the planned approach to the project optimized. While there has been an increase in overall costs, there have also been several opportunities noted for possible reduction in costs.

MHI considers the project construction schedule to be reasonable but all onshore and HDD should be completed in advance of receipt of the cable.

2.5.3 Summary

The costs of the Strait of Belle Isle marine crossing have increased marginally but are considered to be reasonable and within the AACE Class 3 estimate range for Decision Gate 3. MHI is of the opinion that there is an equal likelihood that the costs will decrease, as a result of opportunities through optimized design.

2.6 Muskrat Falls Generating Station Development

In January, 2012, Manitoba Hydro International submitted the "Report on Two Generation Expansion Alternatives for the Island Interconnected Electrical System"[4], which included a review of Nalcor's Muskrat Falls Generating Station plans from the perspective of technical and construction feasibility and cost estimate. This review covers Nalcor's work in preparation for Decision Gate 3 and is also based on information provided by Nalcor in June, 2012.

This section of the report describes the schedule and cost implications of the Muskrat Falls Generating Station including ac Switchyard Upgrades and Transmission Lines to Churchill Falls.

2.6.1 Scope of Work

A high-level review of the Muskrat Falls Generating Station design changes, associated switchyards, and 315 kV transmission lines to Churchill Falls was completed. Cost estimates and construction schedules completed by Nalcor in preparation for Decision Gate 3 were examined and an assessment was made of their reasonableness as inputs to a CPW analysis. Nalcor provided a number of documents to assist MHI in this review.

2.6.2 Muskrat Falls Generating Station

Design and Engineering

The evolution of project scope based on further engineering includes the following:

- Reorientation of the powerhouse in the river by approximately 30^0
- The spillway configuration change from a four-radial gate to a five-vertical gate arrangement
- A significantly more massive powerhouse intake structure
- The south dam changed from a roller-compacted concrete (RCC) structure to a rock fill dam
- The addition of a second service bay at the north end of the powerhouse
- The addition of an RCC cofferdam to the bulk excavation work contract.

From discussions with the Lower Churchill Project (LCP) team and a review of selected change management documents, the changes in project scope are based on sound

[4] Web link, http://www.pub.nf.ca/applications/MuskratFalls2011/MHIreport.htm

engineering principles and have been effectively incorporated into the current project schedule and budget.

The Lower Churchill Project team has demonstrated in documents provided to MHI by Nalcor that the overall design and engineering for the project was 40% complete at the time of submission. Although a comprehensive review of the design was not within the scope of this review, the level of detail provided and evidence in the selected samples of the schedule and budget information supports this degree of completion.

The design and engineering conducted to date are appropriate for a Decision Gate 3 milestone.

2.6.3 Schedule

The target schedule indicates:

- Project start fourth quarter 2012
- Revisions to work package timing and durations as a result of design and engineering changes and refinements
- First power date is July 2017.

The high-level schedule that was reviewed reflected the project contracting strategy and depicted the key project activities that impact the project schedule. The schedule is consistent with the current contract packaging strategy and has considered labour workforce levelling. Based on a selected review, the schedule is supported by a very detailed work breakdown structure that should address project and construction management, and cost control during project execution.

There are a few areas in the schedule that will be challenging, for example, early installation of the project infrastructure, RCC cofferdam construction, and the main structures concrete. In discussion with the project team, however, it is apparent that they are well aware of these issues and are taking measures to manage the risks associated with the components of the schedule.

From MHI's perspective, the project scheduling is comprehensive, detailed, and consistent with best industry practice for similar projects. The current project schedule is appropriate and reasonable to meet the requirements of Decision Gate 3.

2.6.4 Cost Estimates

For Decision Gate 3, the Muskrat Falls Generating Station project cost estimate increased by 21% after allowing for a decrease of escalation and contingency funds in 2012.

The Decision Gate 3 estimate incorporates the recent design changes and is based on upgraded quantities derived from design development, recent pricing and quoting from suppliers, and updated labour pricing.

The Muskrat Falls Generating Station project contingency in the Decision Gate 3 estimate is 9.0%, but maybe higher with allowances if required. This has been discussed with the Nalcor project team, and the Nalcor project team believes that the current Decision Gate 3 estimates input detail and conservative assumptions justify the chosen contingency amount. Nalcor has noted that there is fixed pricing in place for approximately 25% of the project value, thus the 9% contingency is reasonable for Muskrat Falls Generating Station.

Based on the amount of engineering and levels of costs provided, MHI considers the Decision Gate 3 cost estimate to be an AACE Class 3 estimate and therefore would be considered reasonable for the Decision Gate 3 project sanction stage.

2.6.5 Labrador Transmission Assets

The Labrador Transmission Assets (LTA) includes the 315 kV transmission lines from Muskrat Falls to Churchill Falls, and the switchyards at both Muskrat Falls and Churchill Falls.

The evolution of project scope based on further engineering includes the following:

- The inclusion of the 735 kV equipment into the Churchill Falls Switchyard, which had previously been attributed to the Gull Island Generating Station project
- The power lines from the powerhouse unit transformers to the switchyard were changed from underground cables to overhead lines. This change was due to the reorientation of the powerhouse by approximately 30° with the river bed. This allows for a more conventional overhead line arrangement and which would be advantageous from both cost and schedule perspectives.

The current LTA schedule (i.e. 315 kV transmission line) has a projected in-service date of May 2016.

The schedule, which is 33 months long and includes three winter construction periods, accounts for the clearing and construction of the 247 km long 315-kV transmission line. This is a prudent and reasonable schedule given the length of line, the location, and the potential for unusual weather conditions. The schedule durations for AC switchyard design and construction, and procurement of the required transformers and switchgear appear reasonable.

The LTA estimate increased significantly with Decision Gate 3 as a result of including the new 735 kV equipment at the Churchill Falls Switchyard, utilizing current international instead of local construction costs, and increased indirect costs such as construction camps. In consideration of the anticipated significantly increased transmission line construction activity across Canada over the planned period, the increased estimates for construction costs and construction camps are considered appropriate. The LTA Decision Gate 3 estimate includes a 9.1% contingency which is reasonable when combined with conservative inputs on labour and indirect costs. ***Overall the Labrador Transmission Asset Decision Gate 3 estimate is comprehensive, reasonable and prepared in a manner consistent with best utility industry practice***.

2.6.6 Summary

The Lower Churchill Project team developed a comprehensive work breakdown structure for the Muskrat Falls Project that is consistent with the proposed contracting strategy. It is detailed enough to support a Decision Gate 3 level review of the scope, schedule, and budget, and to provide a framework for managing the project going forward.

The Lower Churchill Project has utilized experienced consultants, well recognized independent construction specialists and benchmarking of other recent projects to confirm constructability, productivity rates, and costs. This work, combined with the advancement of the design to the 40% level at the time of submission, provides a significant increase in confidence in the Decision Gate 3 schedule and cost estimate.

From a review of the information provided, Nalcor has performed the design, scheduling and cost-estimating work for the Muskrat Falls Generating Station and the Labrador Transmission Assets with the degree of skill and diligence required by customarily accepted practices and procedures utilized in the performance of similar work. The current Lower Churchill Project design, schedules and cost estimates are considered consistent with good utility practice. The design, construction planning, cost estimate and schedule are comprehensive and sufficiently detailed to support a Decision Gate 3 project sanction and appropriate for input into a cumulative present worth analysis.

3 Isolated Island Option

3.1 Load Forecast

The purpose of this section is to compare the forecasts prepared for the 2012 Isolated Island option and the 2012 Interconnected Island option. The Isolated Island option is based on a higher marginal electricity price because the cost of future generation is more expensive driven by escalating fuel costs. The higher marginal electricity price is expected to reduce future electricity consumption by encouraging conservation and discouraging electric space-heating installations, which will reduce or delay the need for future generation additions.

3.1.1 Comparison of the 2012 Isolated Island option and 2012 Interconnected Island option

The energy and peak forecasts for the Isolated Island option are lower than the respective forecasts for the Interconnected Island option (see Figure 11 and Figure 12). These differences are maximized by 2045, when the Isolated Island option energy forecast and peak forecast are lower by 487 GWh and 86 MW, respectively. After 2045, the gap narrows so that by 2067, the Isolated Island option energy forecast and peak forecast are lower by 276 GWh and 44 MW, respectively.

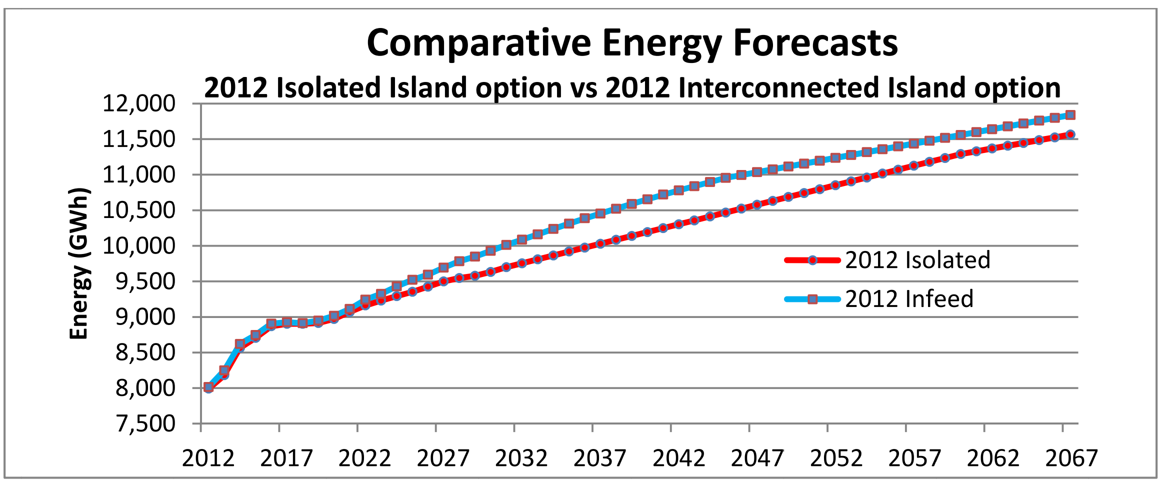


Figure 11: Comparative Energy Forecasts – The 2012 Isolated Island option versus 2012 Interconnected Island option

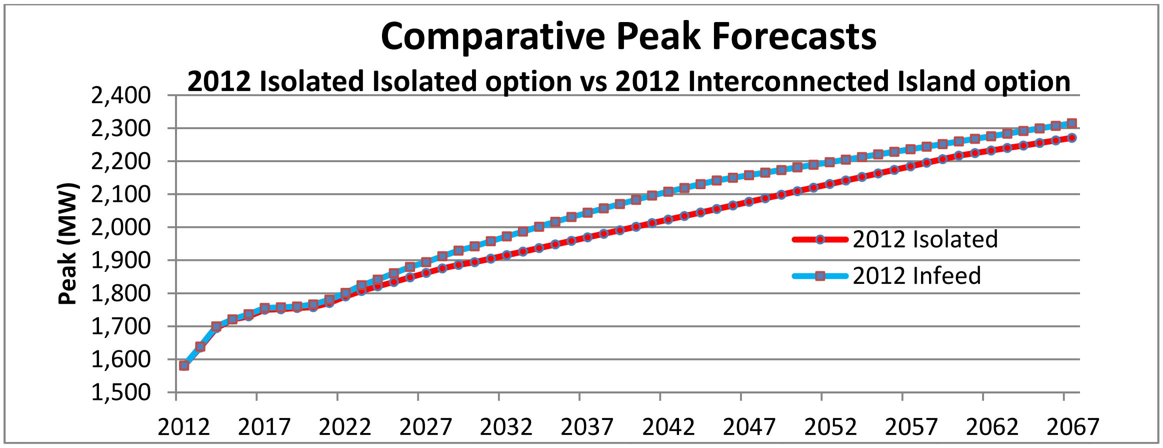


Figure 12: Comparative Peak Forecasts – The 2012 Isolated Island option versus 2012 Interconnected Island option

Table 8 demonstrates that the energy and peak differences between the two options are minimal in 2012. The main cause for the difference in energy consumption is energy reductions in the domestic sector. The general service and other load reductions are minimal throughout the forecast. There is no difference in the industrial load because both options use the same forecast.

Table 8: Comparison of the 2012 Isolated Island option and the 2012 Interconnected Island option – Net Differences

	Energy (GWh)					Peak (MW)
Year	Domestic	General Service	Industrial	Other	Energy	Peak
2012	-13	-6	0	-2	-21	0
2020	-48	-1	0	3	-46	-8
2029	-257	-4	0	-7	-269	-43
2045	NA	NA	NA	NA	-487	-86
2067	NA	NA	NA	NA	-276	-44

The reduction in the domestic forecast occurs because the Isolated Island option is based on a higher marginal electricity price. The higher marginal electricity price is due to the future generation for the Isolated Island option being more expensive than the Interconnected Island option. The higher marginal electricity price reduces the usage of electricity by encouraging conservation and by discouraging the installation of electric space-heating systems. By 2029, the difference in marginal electricity price is 1.13 cents, creating a 928 kWh reduction in domestic average use and a 257 GWh reduction in domestic load.

For both options, the extrapolated forecast assumes that the rate of new electric space-heating loads will be reduced after the 20-year forecast period. Since there is less electric space-heating load in the Isolated Island option, less energy is allocated each year, which widens the energy gap until 2045. By 2045, the Interconnected Island option reaches the maximum constraint for saturation of electric space-heating. The Isolated Island option does not reach the maximum constraint and continues to capture new electric space-heating load beyond 2045, which causes the energy gap to diminish over the later years of the extrapolated forecast period.

3.1.2 Comparison of 2012 Isolated Island Option to Historical Growth

Table 9 compares the 2012 Isolated Island option to historical growth. Total Island energy and peak requirements are expected to grow at a steady rate over the next 20 years. The 20-year Island energy forecast growth rate is 100 GWh and the 20-year Island peak forecast growth rate is 18 MW. These forecasts assume no industrial closures, but the forecast growth rates are still lower than the growth experienced over the last 40 years, which has been adversely affected by pulp and paper mill closures.

Table 9: Annual Growth per Year – Historical Growth and the 2012 Isolated Island option

Sector	Historical Growth Rate			Isolated Island option	
				Forecast Growth Rate	Extrapolated Growth Rate
	1971-2011 (40-Year)	1991-2011 (20-Year)	2001-2011 (10-Year)	2011-2031 (20-Year)	2031-2067 (36-Year)
Domestic (GWh)	77	42	65	42	NA
General Service (GWh)	44	24	32	21	NA
Industrial (GWh)	-13	-58	-132	31	NA
Other (GWh)	8	3	13	6	NA
Island Energy (GWh)	117	12	-23	100	52
Island Peak (MW)	25	3	11	18	10

The 20-year forecast growth rate for the domestic sector (42 GWh) is expected to be the same as the 20-year historical growth rate, which included the economic downturn of the 1990s, and 45% lower than the 40-year historical growth rate (77 GWh). MHI considers the domestic forecast for the Isolated Island option to be overly conservative. The general service, industrial, and other sector forecasts are similar to the 2012 Interconnected Island option, which is discussed earlier in this report, Section 2.1.

3.1.3 Summary

Similar to the findings in the 2012 Interconnected Island option (Section 2.1.4), the primary concern with the 2012 Isolated Island option is that the total Island energy and peak forecasts over the extrapolation period are too low. The extrapolated energy forecast is only 52% of the load expected over the next 20 years. The extrapolated peak forecast is only 56% of the load expected over the next 20 years. These reductions in future growth are significant and may be overly conservative. The extrapolated growth rates are significantly lower due to lower domestic average use, lower electric space-heating saturation, and the assumption of no new industrial loads locating on the Island over the extrapolation period.

3.2 Holyrood Thermal Generating Station

There are a number of alternates for Holyrood Thermal Generating Station, some of which only apply for the Interconnected Island option, some for the Isolated Island option, and some for both options. As most of the plans have been fully documented in the Decision Gate 2 review report, only the changes in scope or costs are noted as part of this report.

The most significant sources of greenhouse gas (GHG) emissions are anthropogenic (or human impact) mostly as result of the combustion fossil fuels. In December 2009, Canada committed to a national greenhouse reduction of 17% below 2005 levels by 2020. Then in June 2010, the government of Canada announced it would take action to reduce carbon dioxide greenhouse gas emissions in the electricity generation sector with regulations on fossil fuels generation. The Government specifically targeted the coal burning sector of the industry but oil burning regulations will not be far behind. The Holyrood Thermal Generating Station emits in excess of 1 million tonnes per year of GHG's. The installation of scrubbers and NO_X burners at a cost in excess of $600 million will clean up particulates and SO_X but will not remove carbon dioxide. Therefore, Holyrood Thermal Generating Station could become a target for Federal Government regulation well in advance of the end of its useful life of 2035. The final regulation for reducing GHG emissions from coal-fired electricity generation were announced by Canada's Environment Minister, the Honourable Peter Kent, on September 5, 2012. Again there was no mention of oil-fired generation but certainly greenhouse gas emissions from oil certainly mirror those from coal.

3.2.1 Holyrood Pollution Control Upgrade

As part of the Isolated Island base case for Decision Gate 3, sulphur dioxide scrubbers (flue gas desulphurization) and particulate collection devices (electrostatic precipitators) were considered to be installed by 2018 and maintained for the economic life of the plant until 2035. Stantec Consulting Ltd. (Stantec) provided an update to the costs outlined in the previous study conducted in 2008.

Findings for Decision Gate 3

Stantec performed a thorough review of the probable cost of the project to the current economic conditions in Newfoundland and Labrador. Stantec also reviewed any changes to environmental regulations that may have occurred that would impact the findings in the original report. Stantec used information from Statistics Canada, Consumer Price Indices for

Newfoundland and Labrador, economic indicators, and Engineering News Records to establish an estimated revised cost.

The productivity factor for labour used in the 2008 Report was still considered appropriate for this study. However, Newfoundland and Labrador are currently experiencing a shortfall of skilled labour due to the increase in construction activity in the region. This is putting pressure on labour rates which were called up to more adequately represent the trend in the construction timeframe. Material prices are somewhat higher in 2012 versus 2008, and despite steel prices being lower overall there was a slight increase in the price allowed for materials.

The review of major equipment and subcontracts concluded that equipment has increased in price equivalent to inflation while the subcontract price of labour and installation has increased significantly.

Summary

The Stantec study concluded that the overall cost to add the scrubbers and precipitators to the Holyrood Generating Station has increased but is generally in line with inflation. The costs outlined in the new report are appropriate for use in the Decision Gate 3 CPW analysis for the Isolated Island Option.

3.2.2 Holyrood Life Extension and Decommissioning

The Holyrood Life Extension was re-evaluated by AMEC in the spring of 2012 to update the prior estimate. The assumption of retaining the thermal generation plant at a capacity factor of 75% is similar to what was envisioned in previous work. Holyrood was the only station evaluated and the study did not examine any additional thermal plants.

Findings for Decision Gate 3

Decision Gate 3 considers continued operation of Holyrood in the Isolated Island Option with plant refurbishments in 2017, 2022, 2027 and 2032, operating until 2035. The reliable operation of all three units was assumed. Plant staffing and contract maintenance was assumed to be equivalent to current levels. In both cases, sulphur dioxide scrubbers (flue gas desulfurization – FGD) and particular collections devices (electrostatic precipitators – ESPs) were considered to be installed by 2018, and maintained for the economic life of the plant. High operating reliability and availability will be required in both cases.

A typical near end-of-life refurbishment would be in the range of $400/kW or $200 million for Holyrood, excluding the costs for the FGD and ESPs. The FGD would likely need to be refurbished in the 2023 to 2027 time range and is estimated to cost approximately $80/kW or $40 million.

Some additional FGD start-up costs and annual capital expenditures of $2 million/year were also likely. A modest refurbishment would occur in the 2025 time frame. The timing of the Holyrood refurbishment would likely be staged from 2013 to 2017. This would allow the plant to continue to provide reliable service and capacity. A second minor refurbishment would also be staged in the 2024 to 2026 time period.

For the Interconnected Island option, Holyrood unit 3 is maintained as a synchronous condenser after the Labrador-Island HVdc link comes online. These costs represent a combination of sustaining capital and decommissioning costs for Holyrood operating as synchronous condensers. The base document for life extension and decommissioning estimation was the Holyrood 20 year capital plan which outlines the Holyrood complex requirements itemized in the CPW analysis as CP2 through to CP5.

Summary

The AMEC study essentially updated the prior Holyrood Thermal Generating Station life extension plan for the Isolated Island option by bringing forward estimates to Decision Gate 3. The costs allocated to the CPW analysis for the Interconnected Island option are of sufficient scope to operate Holyrood unit 3 as a synchronous condenser.

3.2.3 Holyrood Thermal Generating Station Replacement

For the Isolated Island option, the Holyrood Thermal Generating Station plant replacement is planned to consist of three, 170 MW No. 2 low sulfur oil-fired CCCTs. The replacement turbines would be installed in 2032, 2033 and 2036.

3.3 Wind farms

MHI has been studying the proposed wind plan for inclusion into the Isolated Island option, as a separate project. The report of this study is published under separate cover "Decision Gate 3 Review of the Wind Study for the Isolated Island of Newfoundland" [5]. The new generation master plan allows for up to 279 MW in total wind capacity on the Island as part of the Isolated Island option.

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[5] Manitoba Hydro International Ltd. "Decision Gate 3 Review of the Wind Study for the Isolated Island of Newfoundland", September 2012.

The two wind farms proposed in the prior generation plans (St. Lawrence and Fermeuse) were updated to reflect current costs. There was no wind in the Interconnected Island option and none has been added in advance of Decision Gate 3.

Findings for Decision Gate 3

The original Isolated Island option generation master plan (November 2010) included the replacement of St. Lawrence and Fermeuse wind farms in 2028 and 2048 and a new 25 MW wind farm in 2014 with replacement in 2034 and 2054. The revised Isolated Island generation master plan retains all three of the wind farms but also adds a further 50 MW of wind in 2020, 2025, and 2030 including replacements on a 20 year basis plus a 25 MW wind farm added in 2035 and replaced in 2055. This additional 225 MW of wind displaces some base load thermal generation with associated fuel savings.

The Fixed Charges in capital cost estimates, and Operating & Maintenance costs estimates follow industry benchmarks escalated to 2012 dollars and are reasonable as inputs in to the CPW base case analysis.

Summary

MHI has reviewed the costs associated with the fixed charges and operating expenses and find them reasonable as inputs into the CPW analysis.

3.4 Simple and Combined-Cycle Combustion Turbines

The thermal generation facilities considered for both the Isolated Island and Interconnection Island options did not change for Decision Gate 3. The Acres International studies of 1997 and November, 2001 had been used to develop a scheme of simple-cycle combustion turbines (CTs) and combined-cycle combustion turbines (CCCTs) for the Island, at the existing Holyrood site or a new greenfield location. These studies were updated in April, 2012 by Hatch to reflect the current cost and operating environments of both a 170 MW combined cycle and 50 MW simple cycle units.

Findings for Decision Gate 3

In 1997, Acres International and Stone & Webster conducted a feasibility study to install combustion turbines at the Holyrood Generating Station. This original study considered various combined-cycle plants between 150 and 200 MW. The study concluded that natural gas would be unavailable and heavy fuel was eliminated due to excessive maintenance requirements and engine performance derating. Thus the early decision was to fuel the plants using diesel. A two pressure non-reheat cycle was selected and a single turbine configuration was chosen.

In 2001, the study was updated for combined-cycle plants in two capacity ranges, 125 MW and 175 MW. The update included data on plant performance, project capital costs, project schedules, operating and maintenance cost updates and environmental impacts. These costs were then escalated using appropriate indices for use in Decision Gate 3 estimates.

Hatch's 2012 study evaluated the costs for both the 170 MW combined cycle and the 50 MW simple cycle units. However in this case, budget prices were solicited from vendors for major equipment including delivery schedules. In some instances values were updated based on factoring from previous projects.

Summary

MHI finds that the methodology used to develop revised estimates for CT and CCCT thermal generating plants were reasonable and reflects state of the art industry practices for a project at the Decision Gate 3 level.

3.5 Small Hydroelectric Plants

3.5.1 Island Pond and Portland Creek Generating Station Development

The configuration of the Island Pond Generating Station and the Portland Creek Generating Station developments remained unchanged for Decision Gate 3. SNC Lavalin had conducted a detailed project design and engineering analysis in 2006[6]. This study was updated in April, 2012 to reflect the current cost and operating environments.

Findings for Decision Gate 3

As the design and engineering for Decision Gate 3 did not change, a group of relevant escalation indices were tabulated, and a composite index was prepared for the years 2006 and 2012. The resulting escalation index, representing the general cost increase from 2006 to 2012, was applied to all of the unit prices and a revised lump-sum price was established.

Schedule and Cost Estimate for Decision Gate 3

The escalated unit and lump-sum pricing was compared to equivalent pricing from other similar projects. When it was found that the comparative pricing differed significantly with the escalated project pricing, an adjustment was made to the escalation index for that price in the updated project cost estimates. Where practical, such as gate and hoist equipment, an evaluation was made of estimated weights for equipment and applicable unit prices to determine a rational price.

No consideration was given to a premium which could reflect the current state of construction labour in Newfoundland and Labrador.

Unit prices for both Portland Creek and Island Pond hydroelectric projects are in many cases the same for equivalent work items. There are exceptions where there are different foundation conditions from one project to the other.

Summary

The approach chosen to update the estimates on both the Island Pond Generating Station and Portland Creek Generating Station projects is reasonable given the static nature of the design and engineering. ***The revised costs for the small-hydro plants Island Pond and Portland Creek are suitable as an estimate for input into Decision Gate 3.***

[6] Exhibit 5b, SNC Lavalin, "Studies for Island Pond Hydroelectric Project", December 2006

3.5.2 Round Pond Generating Station

The Round Pond Generating Station development was initially investigated by Acres International in 1985, and the concept was updated in a feasibility study conducted by Shawinigan/Fenco in 1987/1988. Newfoundland and Labrador Hydro undertook companion studies of transmission, telecontrol, and environmental issues, and issued a Summary Report in February, 1989 incorporating the findings from the Shawinigan/Fenco investigations. Hatch Consultants updated costs in April, 2012 to reflect current cost and operating environments. This study was used for the Decision Gate 3 analysis.

Findings for Decision Gate 3

Hatch updated the initial cost estimates by applying its own proprietary estimating package to unit prices for all civil works. Hatch applied labour rates based on current labour agreements applicable to the 2012 market environment in Newfoundland and Labrador. The equipment rates were based on leasing of equipment by contractors, with consideration for the present heavy schedule of projects in the province. This approach was considered to be reasonable, although different than the approach used for both the Island Pond Generating Station and Portland Creek Generating Station developments.

Schedule and Cost Estimates for Decision Gate 3

Electrical and mechanical direct costs include the purchase and installation of turbine and generator equipment, and all mechanical and electrical equipment including gates, guides, and hoists. Estimates for mechanical equipment are based on Hatch's database of applicable contract and tender pricing combined with appropriate escalation and rating adjustments to match the Round Pond Generating Station technical parameters and estimate date. Indirect costs were also sufficiently covered.

Summary

The approach selected by Hatch Consultants to update the original studies is reasonable given the static nature of the design and engineering. ***The revised costs for Round Pond are a reasonable estimate suitable for input into Decision Gate 3.***

4 Financial Analysis of Options

4.1 Cumulative Present Worth Analysis

The Cumulative Present Worth (CPW) approach is an acceptable method by which to measure the present worth of alterative options. It focuses only on costs, including capital expenditures for the construction of new facilities, operating costs, fuel costs, and the cost of purchased power. The CPW approach does not take into account cash inflows related to revenues. The preferred option is the outcome which minimizes the cumulative present worth of costs considered over the study horizon.

The CPW approach provides discrete outcomes based on a relative set of input values. When undertaking this analysis, it is appropriate to also consider alternative outcomes. To this extent, a number of scenarios were developed for comparison to the base reference case.

Two base case options were considered by Nalcor, those being the Isolated Island option and the Interconnected Island option. From the perspective of the base reference case, the CPW for the Isolated Island option is $10,778 million, while in contrast the CPW for the Interconnected Island option is $8,366 million. The CPW of projected costs for the Interconnected Island option is $2,412 million less than the Isolated Island option, making it the more attractive option of the two under consideration.

The CPW for each of the two options is comprised of four main inputs:

- Fixed Charges
- Operating Costs
- Fuel Costs
- Power Purchase Costs

Costs for each of the four inputs have been quantified on an annual basis for the period extending to 2067. The sum of the input costs across the various years have then been discounted to 2012 based on a discount rate of 7.0%.

4.2 CPW Results

A summary of the four inputs for the CPW for each of the two options is included in the Table 10 below.

Table 10: Comparison of Options by major input category

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

It is notable that the Fuel Costs under the Isolated Island option account for 62.2% of the total CPW value whereas under the Interconnected Island option, the Fuel Costs account for only 15.8% of the total CPW value. This is attributed to the approximately 45 company owned thermal generation facilities, including the extended life for Holyrood under the Isolated Island option. Table 11 below highlights the fuel consumption between the two options.

Table 11: Fuel consumption between the two options

Barrels ('000)	Isolated Island option	Interconnected Island option
# 2 Fuel	121,632	1,213
# 6 Fuel	61,509	13,398
TOTAL	**183,141**	**14,611**

In contrast however, the early capital investment outlay for the Interconnected Island option is much greater than that for the Isolated Island option. To make a comparison of the CPW for each, it is appropriate to combine the CPW results related to the Fixed Charges with the Power Purchase Costs, as set out in Table 12 below. The greater CPW value and relative percentage related to the Interconnected Island option is attributed to the substantial capital investment tied up in the development of the Muskrat Falls generating station and the capital investment required for the building of the transmission line linking the plant from Labrador to Soldiers Pond.

Table 12: Fixed and PPA charges compared to Total

CPW (000s)	Interconnected Island option	Percent of Total CPW	Isolated Island option	Percent of Total CPW
Fixed Charges	319,400	3.8%	2,555,943	23.7%
Power Purchase Costs	6,467,127	77.3%	763,770	7.1%
TOTAL	**6,786,527**	**81.1%**	**3,319,713**	**30.8%**

4.3 Fixed Charges

The Fixed Charges are related to investment in plant and are intended to capture:

- Depreciation expense based on capital expenditures
- Return on Investment in Plant
- Insurance

The Depreciation Expense is based on the In-Service cost of the plant spread over its expected useful life. The Return on Investment in Plant has been calculated assuming a Return of 7.0% on the undepreciated portion of plant over its useful life. Based on documents provided to MHI by Nalcor, insurance has been calculated assuming a rate of 0.03 percent also on the in-service capital costs of the plant over its useful life.

With respect to the determination of the In-Service cost of plant, the projected total plant cost which has been denominated in 2012 dollars has been escalated each year for the work completed that year, over the period during which the plant is under construction. The escalation factor is designed to take into account factors such as productivity, market conditions, labour force etc. In addition, an Allowance for Funds Used During Construction (AFUDC) has been charged at a rate of 6.25% for the period during which the proposed plant is under construction, recognizing the construction of plant facilities extends beyond one year.

4.4 Operating Costs

The Operating Costs are comprised of two components:

- Fixed Operating and Maintenance (O&M)
- Variable Operating and Maintenance (O&M)

A fixed O&M cost has been determined for each different type of generating facility, expressed in 2012 dollars. For example, all 50 MW CT plants have an annual fixed cost of $551 thousand whereas all CCCT 170 MW plants have an annual fixed cost of $2,550 thousand. Based on documents provided to MHI by Nalcor, the fixed costs have been escalated at a rate of 2.5% forward to the date of in-service for each plant and each year thereafter.

Similarly, a variable O&M cost expressed as dollars per MWh has been determined for each different type of generating facility, expressed in 2012 dollars. The unit rate is applied to the production for each facility. These costs have been escalated as well at a rate of 2.5% forward to the date of in-service for each plant and each year thereafter.

The combined fixed and variable operating costs have then been discounted to 2012 based on a discount rate of 7.0%.

4.5 Fuel Costs

The Fuel component of the CPW incorporates two types of fuel:

- No. 2 Fuel used in CT and CCCT generating units.
- No. 6 Fuel used exclusively at the Holyrood Thermal Generating Station.
    - 0.7% sulphur
    - 2.2% sulphur

The No. 2 fuel is used throughout the period under review to 2067. The No. 6 fuel 0.7% is phased out in 2018 for the Interconnected Island option and in 2036 for the Isolated Island option.

The unit fuel costs are based on a May 2012 PIRA Energy Group (PIRA) forecast from 2012 forward 18 years to 2030, after which Nalcor has inflated the unit prices of fuel at 2.0% per year, compounded.

The combined fuel costs have then been discounted to 2012 based on a discount rate of 7.0%.

4.6 Power Purchase Costs

The Power Purchase Costs differ substantially between the two options.

Isolated Island option

For the Isolated Island option, Power Purchase Costs represent the power purchased from non-utility generators. The Cumulative Present Worth of the power purchased from these sources under this option is $763.8 million. This power is required in addition to the power generated by a number of company owned facilities which will be built during the period under review. The company owned facilities include a variety of Wind, Hydro, Combustion Turbines, Combined Cycle Combustion Turbines and the existing Holyrood facility. Apart from Holyrood, the facilities range in size from 25 MW to 170 MW. The costs to operate the company owned facilities are included under the headings of Fixed Charges, Operating Costs, and Fuel Costs.

Interconnected Island option

The major difference for the Interconnected Island option is the inclusion of the costs relating to the Muskrat Falls generating facility and the Labrador-Island HVdc transmission link. The derivation of the CPW for the Labrador-Island HVdc link is similar to the calculations for each of the variety of the smaller generation units. The CPW related to the Labrador-Island HVdc link is $2,188.6 million.

The derivation of the CPW for the Muskrat Falls generation facility follows a different approach. A Power Purchase Agreement (PPA) approach has been used whereby NLH will sign a take-or-pay contract with Nalcor with the expectation that Nalcor will receive its pre-determined revenue over the life of the asset based on the volumes of energy delivered. The monetization of any power generated by Muskrat Falls in excess to the needs of Newfoundland and Labrador Hydro, will accrue to Nalcor.

The unit PPA rate was determined assuming a threshold Internal Rate of Return (IRR) of 8.4% based on 65% debt/35% equity financing. The proposed PPA unit rate is $65.38/MWh expressed in 2010 dollars. The PPA rate is then escalated at 2.0% per year over the period under review. The CPW related to the Muskrat Falls generating facility is $3,525.9 million. A nominal amount of power with a CPW value of $69.9 million is also purchased from Labrador.

Power is also purchased from non-utility generators. The Cumulative Present Worth of the power purchased from these sources under this option is $682.6 million. Similar to the Isolated Island option, the Interconnected Island option also receives power from a variety of smaller units, except that the Interconnected Island option has only 21 such units in comparison to the Isolated Island option which has approximately 45 company owned facilities.

The combined CPW for the Interconnected Island option Power Purchases is $6,467.1 million.

4.7 Sensitivity Analysis

The Base Case for each of the two options is as noted below in Table 13. A number of alternative cases were prepared in order to bring more perspective to the Base Case. The sensitivities prepared by Nalcor include fuel price, capex, interest rates, and carbon credits.

Table 13: CPW Sensitivity Analysis

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

PIRA Fuel Price Forecast

The Base Case CPW for each of the options is based on the PIRA "Reference Price" which is the price for delivery at a specific location, based on a current 'reference' scenario for various world financial and economic drivers. The PIRA "Expected Price" is the weighted average price forecast of the reference price, high price and low price forecasts. The probabilities assigned to each of the reference price, the high price and the low price have discrete probabilities which can individually vary across various forecasts.

Table 14 below illustrates the impact of experiencing a High Fuel Price Forecast is asymmetrical to that of a Low Fuel Price Forecast. A Low PIRA Fuel Price forecast reduces the CPW 'Preference for the Interconnected Island option' by $1,828 million whereas a High PIRA Fuel Price forecast increases the CPW 'Preference for the Interconnected Island option' by $4,186 million. The consequential negative impact on the CPW associated with an increase in the fuel price forecast is much more substantial than the benefit associated with a decrease in the fuel price forecast.

Table 14: Fuel Price Asymmetry (Scenarios 2, 3, 4 and 11)

CPW (millions)	Preference for Interconnected Island option	Variance from Preference for Interconnected Island option
PIRA Fuel Forecast – Reference Price	2,412	---
PIRA Fuel Forecast – Expected Price	3,015	Increase by 603
PIRA Fuel Forecast – Low Price	584	Decrease by 1,828
PIRA Fuel Forecast – High Price	6,598	Increase by 4,186
Carbon Pricing commencing 2020	2,992	Increase by 580

The carbon pricing sensitivity is included here in the Fuel Price analysis which indicates a $580 million preference for the Interconnected Island option. The purpose for including this here is that the Federal Government recently introduced final regulations on coal burning electrical plants September 5, 2012 and it is anticipated that all thermal power plants will come under regulation in the future.

Capital Cost Projections for Muskrat Falls and Labrador Island Link

Scenarios numbered 5, 6 and 7 reflect variances of capital costs in the order of magnitude of plus 10%, plus 25% and minus 10%. According to an Estimate Accuracy Analysis Report provided by Nalcor to MHI, the engineering and detailed design of the Lower Churchill Project was approximately 40% complete in April 2012. Given a project level of definition of approximately 40%, the project falls within the range of a Class 2 to Class 3 level according to the AACE Classification System. A mid-range amount of 25% level was applied for purposes of setting an appropriate level for the sensitivity capex variance in the CPW analysis.

The sensitivity level of +10% applied to the level of capex falls within the outer limit of the 25% sensitivity and has been included as a directional indicator. The sensitivity level of minus 10% is also a directional indicator. The minus 10% used for the sensitivity analysis increases the CPW preference for the Interconnected Island option to $2.686 billion.

Table 15 below summarizes the impact of comparing three scenarios against the CPW Base Case.

Table 15: Impact of Capex (Scenarios 5, 6 and 7)

CPW (millions)	Preference for Interconnected Island option	Variance from Preference for Interconnected Island option
Base Case CPW	2,412	---
Increase Capex 10%	2,152	Decrease by 260
Increase Capex 25%	1,763	Decrease by 649
Decrease Capex 10%	2,686	Increase by 274

An increase in capital costs of 10% for both Muskrat Falls and the Labrador Island Link, results in a CPW Preference for the Interconnected Island option of $2,152 million, being a decrease of $260 million relative to the Base Case. An increase of 25% in capital costs results in the Preference for Interconnected Island option being reduced to $1,763 million, which is a decrease of $649 million relative to the Base Case. In contrast, should the capital costs related to the construction of Muskrat Falls and the Labrador Island Link decrease by 10%, the Preference for the Interconnected Island option will be increased to $2,686 million, which is an increase of $274 million relative to the Base Case.

Interest Rates

Table 16: Impact of Interest Rates (Scenarios 8, 9, and 10)

CPW (millions)	CPW Preference for Interconnected Island option	Variance from Preference for Interconnected Island option
Base Case CPW	2,412	-
Increase Interest Rate 50 bps	2,259	Decrease by 153
Increase Interest Rate 100 bps	2,096	Decrease by 316
Decrease Interest Rate 25 bps	2,486	Increase by 74

Recognizing the capital expenditures required for the Interconnected Island option are more substantial than for the Isolated Island option, an increase in the interest rates has a greater impact on the CPW results for the Interconnected Island option. An increase of 50 basis points (bps) being one-half of a percent in the interest rate will decrease the CPW preference for the Interconnected Island option by $153 million. A full percent increase in the interest rates will decrease the CPW preference for the Interconnected Island option by $316 million. In contrast, a 25 basis point decrease in the interest rates will enhance the CPW preference for the Interconnected Island option by $74 million.

Load Forecast

Making a finite determination of the load forecast into the future incorporates many variables. The matter is particularly exacerbated by the fact that the numbers of industrial customers are few and therefore, the opportunity for load diversity is limited. The forecast period for this review is 50 years. It is acknowledged there is a possibility that in the short term, the industrial load may decline; however, when put into a long term perspective, it is not unreasonable to expect some opportunity for growth in the industrial sector. Nalcor did not include any growth of industrial load over the long term. From this broader perspective, there appears to be a reasonable offset between the short and long term load forecast projections. In addition, it is noted in section 2.1.4 that the extrapolated energy forecast is only 44% of the load expected over the next 20 years. To the extent Nalcor has not already committed to sell all of the energy output from the Muskrat Falls and Labrador Island HVdc Link facility, the Interconnected Island option is better positioned to address any future additional load increments than with the Isolated Island option. In contrast, should the Isolated Island option be faced with increased future load growth beyond that identified in the 2012 Load Forecast, it would not be unreasonable to expect that it would trigger the need for more combustion turbines and greater fuel consumption.

It is also noted in the CPW analysis prepared by Nalcor that the volumes of energy consumed are greater for the Interconnected Island option relative to the Isolated Island option. The additional volumes are tied to the elasticity factor associated with the lower sales price for customers supplied by the Interconnected Island option. Although the lower unit sales prices benefit the customers, the greater sales volumes attract more absolute costs to the Interconnected Island option. If the impact of the elasticity factor was normalized in the Interconnected Island option, this would enhance the differential between the two options in favour of the Interconnected Island option.

4.8 Conclusions Relating to CPW

1. The results of the CPW review indicate a strong preference in favour of the Interconnected Island option over the Isolated Island option. The Base Case indicates a Cumulative Present Worth preference of $2.412 billion related to the period under review. ***Based on the inputs provided by Nalcor, determination of the CPW base case results and the related sensitivity analysis presented by Nalcor are considered reasonable.***

2. When the CPW results were stress tested for increases in projected capital costs (Capex +25%) for the Interconnected Island option which has a relatively high level of capital investment relative to the Isolated Island option, the CPW preference continued to be in excess of $1.763 billion in favour of the Interconnected Island option. Recognizing the project has moved to a Decision Gate 3 level of review, and acknowledging the amount of contingency included in the Capital Costs estimates for the Interconnected Island option, there is an equal probability the capital costs will decrease as well as increase. A decrease of 10% to the capital costs for the Interconnected Island option will expand the CPW preference to $2.686 billion in favour of the Interconnected Island option.

3. When the CPW results for the Isolated Island option were stress tested for decreases in the projected fuel costs based on the externally provided PIRA Low Fuel Price Forecast, the CPW preference continued to be in excess of $584 million in favour of the Interconnected Island option. Even though the project has moved to a Decision Gate 3 level of review, it is not possible to provide any degree of certainty around fuel costs projected into the future. The stress test of using the High PIRA fuel forecast results in a CPW preference of $6.6 billion in favour of the Interconnected Island option. Within the context of the PIRA forecast parameters, the CPW risk associated with a high fuel price forecast is substantially greater than the benefit associated with the low fuel price forecast.

4. Assuming the energy output from the Interconnected Island option is not fully committed; the Interconnected Island option is better positioned to accommodate future load growth beyond that included in the CPW base case for each of the two options.

5. Any moderate shift (1%) in interest rates will not materially impact the CPW differential between the two options.

5 Conclusions and Recommendations

MHI completed its analysis of both the Muskrat Falls and Labrador-Island HVdc Link, identified as the Interconnected Island option, and the development of various power units on the Island, identified as the Isolated Island option. MHI has found Nalcor's work to be skilled, well-founded, and in accordance with industry practices. Both options have increased substantially in cost from prior estimates released in November 2010. However, the Interconnected Island option continues to have a lower present value cost given the full range of sensitivity analysis and inputs provided by Nalcor to MHI.

Interconnected Island Option

The Interconnected Island option retained the same component mix, namely a 900 MW Labrador Island HVdc link, seven 50 MW CT's and one 170 MW CCCT. There was some realignment of the generating station at Muskrat Falls as a result of detailed design modeling.

The Load Forecast for the Interconnected Island option showed an increase in domestic load for the period to 2029 which was expected due to higher economic forecasts for personal disposable income and population. However the general service sectors show a decrease which would appear to be conservative as it normally mirrors domestic load. The industrial load does not include any new accounts over the entire time span which is very likely conservative. MHI finds that the Interconnected Island Forecast is well founded and appropriate as an input into the Decision Gate 3 process.

AC Integration Studies

The review of the ac integration studies related to the Interconnected Island option indicate that Nalcor is in compliance with good utility practices and that there is an opportunity, during detailed design to optimize final configurations that may enhance system reliability.

HVdc Converter Stations

An assessment of the technical work completed by Nalcor and its' consultants on the HVdc converter stations, electrode lines, and associated station equipment showed the work was reasonable as an input to the Decision Gate 3 process. MHI did recommend some improvements to the project to Nalcor which could be made during the detailed design phase with little impact to the CPW result.

HVdc Transmission Line, Electrode and Collector System

The cost estimates, construction schedules, and design methodologies undertaken by Nalcor and its consultants were reviewed. In MHI's opinion, Nalcor has used a reasonable approach to designing the transmission line to withstand many unique and severe climatic loading conditions along its length. Costs have increased significantly as a result of the need to satisfy reliability requirements as part of the engineering undertaken to date. MHI continues to support selection of a 1:150 year return-period due to the criticality of the HVdc transmission line to the Labrador and Newfoundland electrical system.

Strait of Belle Isle Crossing

A review of the work completed by Nalcor and its consultants has shown that little has changed the design definition and concept in configuration of the marine crossing. Further bathymetric work and a test borehole have shown that costs have increased marginally. MHI considers the marine crossing viable, within the AACE Class 3 estimate range, and can be completed as planned within the allotted time frame.

Muskrat Falls Generating Station

The cost estimates, construction schedules, and design work undertaken by Nalcor and its consultants were reviewed as part of the Decision Gate 3 process. The proposed schedule is appropriate and consistent with best utility practices. Based on the amount of engineering completed and the number of tenders for which estimates have been provided by potential suppliers, MHI considers the Decision Gate 3 cost estimate to be an AACE Class 3 estimate and thus would be considered reasonable for a Decision Gate 3 project sanction. The Labrador transmission assets have also been appropriately designed, scheduled, with a cost estimate consistent with good utility practice.

Isolated Island Option

The Isolated Island option, for Decision Gate 3, is comprised of the following generation resource mix of seven 170 MW CCCTs (net one new), fourteen 50 MW CTs (net 9 new), 77 MW of small hydroelectric plants, and 279 MW (net 225 MW new) of wind farms.

The load forecast for the Isolated Island option is somewhat less than the Interconnected Island option due to the higher marginal price of electricity. However, the general service sectors show a decrease, which would appear to be conservative as it normally mirrors domestic load. MHI finds that the Load Forecast for the Isolated Island is well founded and appropriate as an input into the Decision Gate 3 process.

Holyrood Thermal Generating Station

As part of the Isolated Island option, the Holyrood Thermal Generating Station is assumed to remain in full operation until 2035 with upgrades taking place as previously committed. Pollution control equipment was also scheduled to be installed by 2018. Vendors were canvassed for actual costs of equipment and fuel oil prices were updated to reflect 2012 PIRA estimates.

The Holyrood Thermal Generating Station was scheduled for replacement in 2035 but is now to be decommissioned. Estimates have been updated to reflect this change in operation.

Wind Farms

Wind farms are not deployed in the Interconnected Island option. In the Isolated Island option, a significant amount of wind power has been added, replacing a portion of the generation supplied by thermal generation operating on base load, as recommended in the external 2012 Hatch study.

MHI has been studying the proposed wind plan for inclusion into the Isolated Island option, as a separate project. The report of this study will be published under separate cover "Decision Gate 3 Review of the Wind Study for the Isolated Island of Newfoundland". The new generation resource plan allows for up to 279 MW in total wind capacity on the Island as part of the Isolated Island option.

MHI has reviewed the costs associated with the fixed charges and operating expenses of the wind farms used in the Isolated Island option and find them reasonable as inputs into the CPW base case analysis.

Simple and Combined Cycle Combustion Turbines

In the Interconnected Island option, ten 50 MW peaking units are required to match the increase in expected load along with one 170 MW combined cycle unit. For Decision Gate 3, costs for the CCCT were upgraded for the analysis with input from consultants and vendors.

The Isolated Island option is comprised of fourteen 50 MW CT peaking units with seven base load 170 MW CCCT units, plus 225 MW of wind capacity. While there was no change in the types of units specified, there was an upgrade of costs to reflect current market prices.

Small Hydro Power

There were no changes in the configuration of any of the three small hydropower generating stations to be developed for the Isolated Island option from the previous generation master plan (November 2010). Island Pond GS and Portland Creek GS were updated to current costs whereas additional work was undertaken on Round Pond GS to update a 23 year old study. The costs presented for all three plants are reasonable as an AACE Class 4 estimate suitable as input for the alternative option in the Decision Gate 3 analyses.

CPW

Both the Interconnected Island and Isolated Island options have been updated to reflect current market conditions and cost inputs for the Decision Gate 3 analysis. This work included a re-evaluation of fixed charges, operating costs, fuel costs and power purchase costs and cost estimates were reviewed by MHI. The result of the CPW analysis indicates a preference for the Interconnected Island option of $2.4 billion over the Isolated Island option. Costs of both options have increased proportionately as a result of escalation and scope change. With the assumptions and inputs provided by Nalcor to MHI, the Interconnected Island option remains the least cost option to meet the needs for capacity and energy to supply the forecasted load in Newfoundland and Labrador until 2067.

It is important to note that any monetization of excess power from Muskrat Falls to external markets was not factored into MHI's Decision Gate 3 analysis; the monetization is expected to improve the overall business case of the Interconnected Island option. Also, any uncommitted energy from Muskrat Falls would allow Nalcor to more easily address any large future load additions to the Island of Newfoundland or Labrador.

There remains significant uncertainty in fuel price forecasts which are magnified over the 50 plus years of the study horizon. The Interconnected Island option has much less exposure to variance in fuel price.

MHI Recommends

Given the analysis that MHI has conducted based on the data and reports provided by Nalcor, MHI recommends that Nalcor pursue the Interconnected Island option as the least cost alternative to meet future generation requirements to meet the expected electrical load in Newfoundland and Labrador.

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