3 Reliability Studies

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3.1 Introduction

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

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

In the design, construction, and operation of electrical power systems one important consideration is whether the system will provide a reliable supply of electricity to meet the needs of the customers. There are many ways to define and characterize reliability and by any metric used, additions to a power system should not degrade the reliability performance of the system. As the Island of Newfoundland is currently isolated electrically, investigations on reliability are one of the primary concerns, particularly when large remote generation sources are proposed to be connected to an electric power system through a long transmission line.

Reliability evaluation methods can be generally classified into two categories: deterministic and probabilistic. Deterministic methods are subjective and based on engineering judgement. Industry practitioner's use these deterministic methods as they are simple, intuitive, and easy to understand. However, elements of power system behaviour are unpredictable and random in nature. Also, power systems are increasing in complexity. Thus, probabilistic reliability methods applied to modern power systems are an improved and more accurate method for reliability assessment. Deterministic techniques are being augmented by probabilistic methods particularly for significant projects[63] by leading North American electric power entities; Manitoba Hydro, BC Hydro, Hydro Quebec, Hydro One in Ontario and the Northeast Power Coordinating Council, Inc. (NPCC) have all adopted probabilistic methods to establish system reliability metrics. Industry working groups, who provide guidance to reliability practitioners, are now recommending that these methods be adopted as industry wide standards.

The Island of Newfoundland is fully isolated from the North American grid as depicted in Exhibit 102.[64] The predominant load centre is located on the Avalon Peninsula with a narrow corridor of land connecting the rest of the Island. On this corridor are two parallel transmission lines TL203 and TL237.

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[63] R. Billinton, J. Satish, "Adequacy Evaluation in Generation, Transmission, and Distribution Systems of an Electric Power System", 1993, IEEE 0-7803-1319-4/93
[64] Exhibit 102, "Provincial Generation and Transmission Grid," January 2011

A third transmission line is planned for this corridor along with the proposed HVdc transmission line. Generation largely resides west of this thin corridor at Bay D'Espoir and other plants north and west. A large transfer of power flows along the transmission corridor defined by transmission lines TL202/TL206 and TL203/TL237. The load east of Bay D'Espoir is approximately 67% of the island demand of 1052 MW in 2012[65]. The configuration of the transmission system, along with the location and arrangement of available generation, as well as the location of the loads must be considered in a reliability study.

Nalcor has defined their generation planning criteria for generation in terms of Loss of Load Hours (LOLH). Generation must be installed and have sufficient capacity and energy as defined to meet LOLH[66]:

> *"Capacity: The Island Interconnected System should have sufficient generating capacity to satisfy a Loss of Load Hours (LOLH) expectation target of not more than 2.8 hours per year.*
>
> *Energy: The Island Interconnected system should have sufficient generating capability to supply all of its firm energy requirements with firm system capability."*

The 2.8 hours per year is an important metric as it is used as one of the inputs to determine both the timing and size of new generation in the Strategist Program. The reserve margin is determined considering both the Forced Outage Rates (FOR) of generating units and maintenance requirements. For the isolated power systems, higher reserve margins are normal. Periodically, review of system adequacy must be assessed to determine the financial impact of carrying this additional reserve margin.

Reliability considerations change when interconnections are present in the power system. Interconnections may bring reliability improvements as generation resources can be shared with neighbours. Nalcor has defined the first interconnection to the Island from Labrador with the Labrador-Island Link HVdc System starting at Muskrat Falls and terminating at Soldier's Pond on the Avalon Peninsula. A second link discussed in the Technical Note is the Emera 500 MW HVdc link from Bottom Brook to Lingan, Nova Scotia. The Emera curtailable capacity to Nova Scotia Power noted in that document is 162.2 MW with 300 MW import capability onto the Island of Newfoundland.

Reliability assessment is most often used to determine the adequacy of generation and/or transmission to meet the load. Current industry trends in practical generating systems, extend adequacy analysis from the conventional first level assessment to include major transmission limitations.

When reliability assessments are to be performed, data is derived from a number of sources based on the system components in order to fully characterize reliability. Existing reliability metrics in use by Nalcor are as follows:

[65] Exhibit 106, Nalcor, "Technical Note: Labrador – Island HVdc Link and Interconnected System Reliability", October 2011
[66] Nalcor's Submission to the Board of Commissioners of Public Utilities with respect to the Reference from the Lieutenant-Governor in Council on the Muskrat Falls Project, November 2011

- For hydraulic generation units, the Derating Adjusted Forced Outage Rate (DAFOR) is used as the Forced Outage Rate input into Strategist, or the Canadian Electricity Association – Equipment Reliability Information System (CEA ERIS) report.
- For thermal units, Nalcor is using their experience from their existing units.
- For CCCTs, Nalcor has specified a forced outage rate (FOR) of 5%.
- For the Labrador-Island Link HVdc System, Nalcor has specified a FOR of 0.89% on a per pole basis. This value is listed in Exhibit 26; however, it is not evident how this value was obtained from this Exhibit.

A summary of documents relevant to the review and analysis of reliability are described in this report, then followed by HVdc pole and bipole outage statistics, and then by a discussion on probability reliability assessment as a best practice.

3.2 Exhibit Documents Reviewed

A brief summary of some of the major documents reviewed is provided as follows:

1. Exhibit 12, "Forced Outage Rates Summary Sheet" outlines the input values used for the Strategist generation resource planning tool.

2. Exhibit 26, "Forced Outage Rates 2006 Update" is a document that describes the values, and the sources used in Exhibit 12 and is an input into the development of more advanced reliability models.

3. Exhibit 33, "Summary of Ocean Current Statistics": This report reviews and summarizes the available ocean current data of the Strait of Belle Isle. The mean and maximum expected current speeds along the potential HVdc cable system corridor route are estimated based on historical data records. The mean and maximum expected current speed estimates are provided for each season and three different depth levels. These estimates may be used as input for the development of a reliability model of the HVdc marine crossing cable system.

4. Exhibit 34, "Review of Fishing Equipment": The studies described in this report identify some of the specific fishing gear and related equipment which may interact with the Strait of Belle Isle HVdc cable system. The study also estimates the expected durations and number of passes over the possible cable crossing areas for existing and potential fishing activities. This information could be used to estimate the Strait of Belle Isle HVdc cable system risks exposure to various fishing operations. The information can also be used in the development of a reliability model of the HVdc marine crossing cable system.

5. Exhibit 35, "Nalcor Strait of Belle Isle Iceberg Cable Risk": This report presents the application of a drift model based on a Monte Carlo Simulation to assess iceberg risks to cables laid on the seabed in the Strait of Belle Isle. The simulation results are compared with the iceberg scour data derived from surveys for model evaluation and risk analysis. The report also estimates iceberg risks to cables laid on the seabed for particular routes and configurations. This information can be used to estimate the Strait of Belle Isle HVdc cable system risks exposed to

icebergs. The information can also be used as input into the development of a reliability model for the HVdc marine crossing cable system.

6. Exhibits CE-40, CE-41, CE-42, CE-43, CE-44: These reports present the results of a series of feasibility studies on the seabed installation of HVdc power cables across the Strait of Belle Isle. These studies include technical feasibility of dredging and backfilling, shore approach trenches for a cable crossing including horizontal directional drilling (HDD), a rock berm method for cable protection and the Strait of Belle Isle seabed crossing conceptual design. These reports provide useful information in understanding the risks associated with the HVdc cable system. The information may be used in the development of a reliability model of the HVdc marine crossing cable system.

7. Exhibit 48, "Newfoundland and Labrador HVdc Link Reliability Studies": This report summarizes the results of probabilistic reliability studies on the proposed ±400 kV Labrador-Newfoundland HVdc project, from 1981. Annual failure rates and repair times are estimated for the overhead portion (ac/dc lines), cable crossing of Strait of Belle Isle and HVdc terminal equipment, mainly based on Cigré statistics. An overall system reliability model is developed from the subsystem or component reliability models. The HVdc system reliability is evaluated for both dc and ac links from Gull Island to Churchill Falls in terms of probability, frequency and duration of various levels of transfer capability using an analytical approach.

8. Exhibit 57, "Reliability of the Strait of Belle Isle HVdc Cable System": The studies described in this report are similar to those provided in Exhibit 48. They include the review of operating history of undersea cable systems similar to those alternatives proposed for the Strait of Belle Isle at that time, the estimate of iceberg scour risk, the assessment of the reliability of the proposed cable alternatives, incorporation of the cable system reliability models into the overall system reliability model and the development of an equivalent reliability model for the overall HVdc system. The equivalent reliability model of overall HVdc system is expressed in terms of a single generating unit capacity and associated forced outage rate.

9. Exhibit 106, "Labrador-Island HVdc Link and Island Interconnected System Reliability": This report reviews various system reliability components including planning, operation, design, and examines the reliability impacts of the Labrador-Island Link HVdc system, and compares the reliability of the two options. The reliability effects of the Labrador-Island Link HVdc system are assessed considering single pole or bipole outages and the probabilities of these events are factored into reliability index calculations. The study methodology described in this report is deterministic in nature for a limited set of assumptions and conditions.

3.3 LOLH and LOLE Defined

The two most commonly used indices in probabilistic reliability studies are the Loss of Load Expectation (LOLE) and the Expected Unserved Energy (EUE)[67 68]. The LOLE measures the likelihood of the system not being able to carry the desired load. Different reliability indices can be obtained by using different load models:

- LOLE index (days/year) is evaluated using daily peak load values, for example 0.1 days/year or a one day in ten year event.
- LOLH index (hours/year) is obtained using hourly load values, for example 2.8 hr/yr. This metric may also sometimes be referred to as LOLE which only adds to the confusion.

It is not valid to obtain the LOLE by simply multiplying LOLH by 24, because the hourly load profile is normally quite different from that of the daily peak load. The ratio of the LOLE in hours/year (LOLH) over the LOLE in days/year is always less than the value of 24 in an actual power system[69].

Generally each utility sets its own level of acceptable risk but a LOLE of 0.1 days/year on an annual base is unofficially used across North America particularly for resource adequacy planning [70 71 72]. Nalcor has determined that "The Regional Reliability Organization criterion of one day in 10 years is more stringent than NLH's LOLH of 2.8 hours per year which equates to about one day in every five years"[73].

The LOLE index is not often easily interpreted or understood, and it is sometimes translated into another risk index – load carrying capability. The load carrying capability is the maximum system peak load that can be carried by a system without violating the acceptable LOLE criterion.

The EUE is the amount of energy not delivered to the customer as a result of the loss of load due to random outages. This index has become the preferred index as it represents something physical, such as energy delivered to customers. This index can be converted to a monetary value, as done with Manitoba Hydro's Bipole III studies, and therefore provides the means to assess cost implications of system risks. Nalcor makes a statement on page 32 of Exhibit 106, that it is difficult to calculate the cost of increasing quality and requires the utility to have a sound understanding of the value of outage to each of its customer classes[74]. However, sophisticated study tools available today allow EUE to be easily calculated as part of reliability adequacy studies.

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[67] R. Billinton and R. Allan, Reliability evaluation of power systems, 2nd Edition, Plenum Press, New York, 1996
[68] Wenyuan Li, "Risk Assessment of Power Systems: Models, Method, and Applications", IEEE Press, Wiley-Interscience, 2005
[69] R. Billinton and D. Huang, "Basic concepts in generating capacity adequacy evaluation", in Proc. Int. Conf. Probabilistic Methods Applied to Power Systems PMAPS 2006, 2006, pp. 1-6
[70] Resource and Transmission Adequacy Task Force of the NERC Planning Committee, "NERC Resource and Transmission Adequacy Recommendation", June 2004
[71] RFC Standard BAL-502-RFC-02: Planning Resource Adequacy Analysis, Assessment and Documentation, December 2008:
[72] Midwest ISO Business Practices Manual: Resource Adequacy, June 2009:
[73] Nalcor's Submission to the Board of Commissioners of Public Utilities with respect to the Reference from the Lieutenant-Governor in Council on the Muskrat Falls Project
[74] Exhibit 106, Nalcor, "Technical Note: Labrador – Island HVdc Link and Interconnected System Reliability", October 2011

3.4 HVdc System Reliability Review

Historically, HVdc transmission system performance suffered from poor reliability with high Forced Energy Unavailability (FEU) and high Scheduled Energy Unavailability (SEU) indices when compared to ac transmission lines of the same power rating. The following two tables only provide two years of recent data for systems that report. For a complete discussion, see Cigré B4-209, "A survey of the Reliability of HVdc Systems throughout the World During 2007-2008", 2010.[75] The metrics on these tables are:

f_p = number of pole outages per terminal per year

f_b = number of bipole outages per bipole per terminal per year

d_p = average duration of pole outages in hours

d_b = average duration of bipole outages in hours.

Table 18 shows the average frequency and duration of converter, pole and bipole outages for two-terminal and multi-terminal systems. The frequency of outages is given on a per terminal basis and does not include transmission lines or cables.

Table 18: Forced Outage Statistics, Two Terminal Systems - One Converter per Pole

System	2007				2008				Average to 2008				
	Pole		Bipole		Pole		Bipole		Years	Pole		Bipole	
	fp	dp	fb	db	fp	dp	fb	db		fp	dp	fb	db
Skagerrak 1 & 2	1.25	3.1	0.00	0.0	2.00	3.8	0.50	1.0	20	1.54	17.1	**0.13**	**1.03**
Skagerrak 3 (1)	1.00	1503.2	-	-	0.50	4360.4	-	-	15	1.53	**484.2**	-	-
Square Butte	1.00	4.1	1.50	0.3	5.25	0.8	0.00	0.0	18	2.85	6.2	**0.42**	**2.27**
CU	0.50	23.8	0.00	0.0	1.25	58.5	0.00	0.0	20	1.71	4.6	0.28	1.66
Gotland 2 & 3	0.25	0.8	0.00	0.0	0.50	46.6	0.00	0.0	20	**0.38**	35.8	0.20	1.49
Fennoskan (1)	2.00	14.2	-	-	1.50	46.4	-	-	19	2.26	10.1	-	-
SACOI (3)	3.33	1.7	-	-	1.67	2.5	-	-	16	**4.90**	**2.6**	-	-
New Zealand Pole 2 (3)	2.50	4.3	-	-	0.50	0.7	-	-	17	1.65	2.7	-	-
~~Kontek (1)~~	~~0.50~~	~~2.7~~	-	-	~~1.00~~	~~32.0~~	-	-	~~7~~	~~0.86~~	~~15.7~~	-	-
~~SwePol (1)~~	~~0.50~~	~~2.4~~	-	-	~~2.00~~	~~1.7~~	-	-	~~8~~	~~3.56~~	~~21.0~~	-	-
~~Kii Channel~~	~~0.00~~	~~0.0~~	~~0.0~~	~~0.0~~	~~0.00~~	~~0.0~~	~~0.00~~	~~0.0~~	~~8~~	~~0.16~~	~~99.6~~	~~0.00~~	~~0.00~~
~~Grita (1)~~	~~4.00~~	~~42.2~~	-	-	~~4.5~~	~~9.3~~	-	-	~~5~~	~~2.70~~	~~17.1~~	-	-

In Nalcor's technical note on reliability, Exhibit 106 [76], HVdc pole outages are discussed with the data selected from the Cigré B4-209 survey. Nalcor has also stated that only systems with 15 years or more of service are considered by them.[77] Values not meeting this criterion have been stroked out from Table 18. The range of forced energy unavailability (FEU) is 0.38 to 4.9 pole failures per terminal per year, with durations of 2.6 to 484.2 hours.

[75] CIGRE B4 – 209, "A survey of the Reliability of HVdc Systems throughout the World During 2007-2008", 2010
[76] Exhibit 106, Nalcor, "Technical Note: Labrador – Island HVdc Link and Interconnected System Reliability", October 2011
[77] Response to RFI PUB-Nalcor-165

Nalcor describes in detail how they plan to manage the balance of demand, with alternative supply and HVdc pole overload, for a single pole outage and no Maritime Link. In this document a statement is made that

> *"if the Labrador – Island Link is providing maximum deliveries (i.e. 807.9 MW), there must be a minimum of 180.7 MW of spinning reserve carried by the Island Interconnected System generation to cover the capacity deficiency for loss of a pole and/or loss of the largest unit on the Island System. The additional inertia provided by the proposed high inertia synchronous condensers will assist in ensuring frequency on the system is maintained above under frequency load shedding levels so that the governors on the hydroelectric units carrying the spinning reserve can respond to loss of the pole and increase output to make up the 180.7 MW deficiency."*

When load is shed by the special protection system due to a loss of supply, the frequency will decay and then recover to a control point that would be less than nominal frequency due to the bandwidth setting in the frequency error control loop. Thus, in practice the entire 180.7 MW generation deficiency would not be recovered by governor action alone from spinning reserve. There must be an operator dispatching new generation to make up the short fall for frequency to fully recover. If the shortfall exceeds capabilities of the pole with the 150% continuous overload rating, then new generation must be dispatched within the ten minute window provided in the HVdc system rating specification. One must also consider the reliability of the starting sequence for CTs as the ten minute window is a short time for an operator to take corrective action. CTs typically have a start time of 30 minutes, however, they may be configured for quicker starting times. The CT start sequence probability of success should be factored into the reliability model.

Bipole outages are more severe than single pole outages. In Exhibit 106, Page 16, Nalcor has restated the frequency and durations of bipole outages.[78] From this, a reliability engineer would anticipate that the Labrador-Island Link HVdc system would see a bipole outage every 0.13 years (one outage every 7.7 years) to 0.42 bipole outages per year (one every 2.3 years) with the maximum duration of 2.27 hours. In this situation, the bipole will be returned to service in under three hours for converter station forced outages. Unfortunately, this does not provide a complete picture of the performance of the Labrador-Island Link HVdc system together with the 1100 km overhead transmission line, and the 30 km Strait of Belle Isle marine crossing. These must also be factored into the reliability equation. Table 2 of Exhibit 106 is incomplete and does not show the reliability performance of HVdc systems with marine crossings. Note: one may argue that the cable configurations outlined are not comparable to the Strait of Belle Isle marine crossing with its spare cable. This system would not see the same severity of outages.

Table 19 provides complete details from the Cigré B4-2009 survey document and outlines all values for the Number of Forced Outages and Equivalent Durations of Overhead and Submarine Cable lines. Some of the submarine cable outage durations are long due to lack of spare cable, and the amount of time required to locate, plan, and affect cable repairs. Note: this table includes back to back converters which will not have transmission line outages.

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[78] Exhibit 106, Nalcor, "Technical Note: Labrador – Island HVdc Link and Island Interconnected System Reliability", October 2011

Table 19: Number of Forced Outages and Durations of Overhead and Submarine Cable lines

Project	2007		2008	
	Number	Duration (hr)	Number	Duration (hr)
Skagerrak 1 & 2	0	0.0	0	0.0
Skagerrak 3	1	2.3	0	0.0
Vancouver Island Pole 1	0	0.0	0	0.0
Square Butte	2	194.6	1	64.5
Shin-Shinano 1	0	0.0	0	0.0
Shin-Shinano 2	0	0.0	0	0.0
Nelson River BP1	0	0.2	2	2.1
Nelson River BP2	1	0.0	4	0.6
Hokkaido-Honshu	0	0.1	0	0.0
CU	1	0.0	0	0.0
Gotland 2 & 3	0	0.0	0	0.0
Itaipu BP1	0	0.0	0	0.0
Itaipu BP2	1	0.1	0	0.0
Highgate	0	0.0	0	0.0
Virginia Smith	0	0.0	0	0.0
McNeil	0	0.0	0	0.0
Fennoskan (cable failure)	1	1005.5	0	0.0
SACOI (cable failure)	3	530.3	4	581.0
New Zealand Pole 2	1	0.3	5	9.3
Sakuma	0	0.0	0	0.0
Kontek (cable failure)	1	1624.5	0	0.0
Minami-Fukumitsu	0	0.0	0	0.0
SwePol	0	0.0	0	0.0
Kii Channel	0	0.0	0	0.0
Grita (cable failure)	1	610.5	1	2.5
Rivera	0	0.0	0	0.0
Higashi-Shimizu	0	0.0	0	0.0
Basslink	0	0.0	0	0.0

As this is only a two year snap shot of survey data, the data is not representative of the overhead and submarine cable reliability and is only useful to demonstrate that failures do occur, and in some cases, for extended periods of time. The amount of plant installed to cover off risk factors and contingencies (for example, overload rated submarine cables with a spare cable, converter station pole overload, redundant auxiliary supplies, backup generation, etc.) mitigate these risks through appropriate design.

Modern HVdc converter stations have proven very reliable. New HVdc converter stations are normally specified in tender documents with a Forced Energy Unavailability of 0.5% with a guaranteed rate of 1% with penalties for poor performance.

Probabilistic reliability studies, which are covered in section 3.8 are necessary to evaluate the expected costs of the risks and assess the performance of these HVdc converter stations, the HVdc transmission line, and the marine cable crossings together as the Labrador-Island Link HVdc system.

3.5 Equivalent Short Circuit Ratio

Nalcor's Exhibit 106 justifies its 50-year return period for transmission line design based on the inability of the Labrador-Island Link HVdc system to deliver power at Solder's Pond if the 230 kV transmission system was not intact. When taken to the extreme, if there is no available 230 kV transmission lines at Soldier's Pond, this would result in no power delivery, and if the entire 230 kV transmission system emanating from Soldiers Pond were compromised, this would be true.

In order for the Labrador-Island Link HVdc system to deliver power to the Soldiers Pond Converter Station utilizing Line Commutated Converter technology, a supply of voltage and reactive power is required at the 230 kV ac bus. The reactive power would be available from the three 300 MVAr synchronous condensers located at Soldiers Pond, and starting voltage and power would have to come from a nearby generating station. The amount of power delivered by the Labrador-Island Link HVdc system is variable on a dispatcher controlled power order. With modern HVdc conventional converter designs, it is possible to deliver low amounts of power (less than 10% on converter ratings).

Nalcor states that "the 230 kV transmission system must be reasonably intact to provide the necessary equivalent short circuit ratio (ESCR …)" for Soldiers Pond to function properly[79]. ESCR is a simplistic but useful index in the analysis of dc systems. ESCR is defined by the following formula:

$$ESCR = \frac{SCMVa - Qf}{Pdc}$$

Where:

ESCR is the equivalent short circuit ratio

SCMVa is the short circuit rating of the ac system

Qf is the reactive power rating of the filters and capacitors on the ac bus

Pdc is the power transmitted by the HVdc system.

In words, the equivalent short circuit ratio is the short circuit level of the ac bus (used to define the strength of the ac system which is dependent on the number of 230 kV transmission line connections), less the reactive power rating of the filters and capacitors, all divided by the dc power. At full rating, an ESCR less than 2.0 (as is the case at Soldiers Pond) is considered a weak system which presents special control and operational issues for dc systems.

However, ESCR tends to increase with less dc power delivered, i.e. with a reduction in Pdc with no change in short circuit levels. One can interpret that ESCR is not a barrier to deliver dc power in reduced amounts provided some of the 230 kV transmission system is intact.

[79] Exhibit 106, Nalcor, "Technical Note: Labrador – Island HVdc Link and Island Interconnected System Reliability", October 2011

3.6 Component and Sub-system Reliability Modeling

The components and/or subsystems that should be modeled in a probabilistic reliability assessment usually consist of generating units and major transmission facilities. The average performance data from the 2004 Canadian Electricity Association Annual Report on Generation Equipment Status used to develop Forced Outage Rates (FOR) for various types of generating units is well founded and reasonable. Although no detailed information is available for review on the Labrador-Island Link HVdc system converter station reliability, reliability data from manufacturers or from data collected on similar systems[80] can be used to model converter station components for reliability studies. Some of the procedures and methodologies described in earlier reports prepared by Power Technologies Inc. (PTI) (Exhibit 48 "Newfoundland and Labrador HVdc Link Reliability Studies" and Exhibit 57 "Reliability of the Strait of Belle Isle HVdc Cable System") are still applicable and may be used to develop reliability models for the Labrador-Island Link HVdc system with appropriate updates and modifications. The model and study development may involve:

1. A review of technical specifications of the proposed system and operating history of similar installations around the world;
2. An estimate of specific risks, for example: icebergs, fishing dredges and ocean currents for the Strait of Belle Isle cable crossing and rime ice and salt contamination for the overhead HVdc line;
3. Develop reliability component models of the proposed cable, overhead line and converter stations; and
4. Amalgamate the various component reliability models to form the overall Labrador-Island Link HVdc system reliability model.
5. Link the Labrador-Island Link HVdc system model into the island power system reliability model.
6. Perform the reliability study.

A 0.89% forced outage rate is specified by Nalcor for the Labrador-Island HVdc Link.[81] Currently most manufacturers are able to provide HVdc systems with a reasonably high degree of reliability. The information documenting the derivation of the Labrador-Island Link HVdc system FOR of 0.89% on a per pole basis was not available for MHI's review. However, MHI has compared the Labrador-Island Link HVdc system pole FOR rate of 0.89% with published information and that of Manitoba Hydro's HVdc system (including the HVdc transmission line) and finds it acceptable. However, this FOR should be replaced by a more advanced and comprehensive reliability model incorporating all components of the Labrador-Island Link HVdc system.

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

[81] Exhibit 12, Nalcor, "Forced Outage Rates Summary Sheet", June 2006

3.7 Deterministic Reliability Assessment

Deterministic reliability assessment is predominantly used in Nalcor's Exhibit 106 to assess impacts of the loss of generation: either the largest unit on the Island, the Labrador-Island Link HVdc system in one or two pole blocks, or the Emera link. This type of assessment provides snap shots in time of system performance based on a set of assumptions and fixed load pattern.

Deterministic approaches are rather simplistic and do not provide an exhaustive examination for system resource adequacy based on more sophisticated models and techniques.

3.8 Probabilistic Reliability Studies

One of the important factors that should be considered in evaluating power system enhancement alternatives is the reliability benefit associated with each option. Risk based or probabilistic reliability evaluation is widely accepted in the power industry to determine the ability of a component, a subsystem or a system to perform its intended function. The numerous uncertainties facing the industry drive a need to use probabilistic evaluation methodologies in power system reliability. The electric power industry particularly in North America is, therefore, adopting the use of the probabilistic reliability assessment approach.[82] [83] [84]

In probabilistic methods, a full model of the generators, transmission lines, HVdc system, maintenance schedules, unit dependencies, and other significant risk factors are considered along with variations in the system load. A commonly used method to process reliability calculations is to use Monte Carlo simulations. These tools randomly change various element states (fail the element) across the model.

3.9 Industry Adoption of Probabilistic Methods

In 2004, the Planning Committee (PC) of the North American Electric Reliability Council (NERC) recommended that each NERC region or sub-region should establish a resource adequacy criterion (or criteria) based on probabilistic metrics and perform probabilistic resource adequacy assessments periodically in order to demonstrate that the regional or sub-regional resource adequacy requirements are being satisfied. In 2008, the Reliability First Corporation (RFC) developed and approved a standard in order to establish common criteria in resource adequacy evaluation for the RFC region. The standard puts in force the use of a probabilistic approach in resource adequacy evaluation.[85]

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[82] Resource and Transmission Adequacy Task Force of the NERC Planning Committee, "NERC Resource and Transmission Adequacy Recommendation", June 2004
[83] RFC Standard BAL-502-RFC-02: Planning Resource Adequacy Analysis, Assessment and Documentation, December 2008f
[84] NERC's Generation and Transmission Reliability Planning Models Task Force, "Generation and Transmission Reliability Planning Models Task Force Final Report on Methodology and Metrics", September 2011
[85] Resource and Transmission Adequacy Task Force of the NERC Planning Committee, "NERC Resource and Transmission Adequacy Recommendation", June 2004

In 2010, NERC's Generation and Transmission Reliability Planning Models Task Force (GTRPMTF) recommended a common generation and transmission reliability modeling methodology and a common set of probabilistic reliability indices for the purpose of resource adequacy assessment across NERC. The GTRPMTF recommendations particularly emphasize the inclusion of major transmission restrictions in resource adequacy evaluation[86].

Risk based reliability evaluation has gained renewed importance in the industry particularly since the 2003 North American blackout. The predominant application of probabilistic techniques is still in the domain of adequacy including consideration regarding transmission restrictions.[87,88,89,90] The terms "adequacy" and "reliability" are, therefore, interchangeable in most cases and are identical in the following discussions in this report. Generally probabilistic reliability evaluation in power systems includes, but is not limited to, determination of component and sub-system outage models, evaluation of overall system adequacy including alternative comparisons and assessment of economics associated with various system reliability levels, including value based reliability analysis[91]. Within this perspective, various available studies, reports and related information regarding the reliability aspect of the two supply options have been reviewed.

The following are some of the examples where the industry performs probabilistic reliability studies:

1. Northeast Power Coordinating Council, Inc. (NPCC) performs annual LOLE studies for the region considering transmission restrictions.
2. In other NERC regions, individual utility or Independent System Operator (ISO) planning authorities, similar studies are performed annually. For example, the MISO utilities in RFC, MAPP and Manitoba Hydro in Midwest Reliability Organization (MRO), BC Hydro, Idaho Power, and California ISO in Western Electricity Coordinating Council (WECC) all perform these studies.
3. Particular project examples include studies done by BC Hydro for the Vancouver Island Transmission Reinforcement Project, assessment of Manitoba Hydro's HVdc Bipole III alternatives, and Hydro One's studies on transmission planning and asset management in Ontario.
4. There are several consulting companies performing probabilistic studies in North America for example GE (using MARS tool), ABB (using GRIDVIEW tool), Associate Power Analyst (using NARP tool) and Astrape Consulting (using SERVM tool).

[86] RFC Standard BAL-502-RFC-02: Planning Resource Adequacy Analysis, Assessment and Documentation, December 2008
[87] Midwest ISO Loss of Load Expectation (LOLE) Studies
[88] Northeast Power Coordinating Council Interregional Long Range Adequacy Overview, November 2010
[89] PJM CETO Report, October 2009
[90] Glenn Haringa, "California Independent System Operator for Planning Reserve Margin (PRM) Study-2010-2020", April 2010
[91] R. Billinton and R. N. Allan, Reliability Evaluation of Engineering Systems: Concepts and Techniques, Plenum Press, New York, 1992

3.10 Reliability Comparison of the Two Options

The proposed Labrador-Island Link HVdc system is a crucial part of the Infeed Option. The impacts of the HVdc link on the overall system reliability performance should, therefore, be quantitatively evaluated in order to provide valuable inputs to the decision making process. The most performed studies in the power industry is resource adequacy assessment considering transmission restrictions.[92,93,94] The primary concern in resource adequacy studies is to assess the capability of system resources to serve the total system demand.

The impact of the proposed Labrador-Island Link HVdc system can be quantified in terms of these commonly used reliability indices of load carrying capability, LOLE/LOLH or EUE. However, there are no such probabilistic study results available for review. The studies described in Exhibit 106 do not use the probabilistic methods nor fully address this concern.

Comparisons of the two options in terms of reliability should be one of the important inputs to the decision making process. The relative reliability level of these options can be determined based on a series of comparative analyses with a do nothing option, Isolated Island Option, and the Infeed Option. Reliability assessment for the Infeed Option could consider the generation, load, firm export/import sales, demand side management programs and interruptible load, particularly as related to the proposed Labrador-Island Link HVdc system associated with Muskrat Falls' generation. The Isolated Island Option evaluation may include all of the above with the exception of the transmission. A comparison of system reliability in terms of LOLH for the two alternatives produced from the Strategist Program shows that the reliability of the Infeed Option is slightly better than that of the Isolated Island Option. [95] A full Labrador-Island Link HVdc system reliability modelling is, however, not considered in this comparison as the HVdc system was only modelled as an unrestricted thermal source with an FOR of 0.89%.

The resource adequacy assessment could also include a comparison of system reliability in terms of EUE and associated risk costs. [96,97,98] The risk costs can be evaluated using either the method based on risk cost function or on the method based on gross domestic product (GDP)[99,100]. In the first method, a risk cost function is obtained from customer surveys and the relevant statistics analysis. Usually the risk cost is regional and system specific. In the second method the risk cost is estimated based on GDP

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[92] Wenyuan Li, "Probabilistic Reliability Assessment of Central Vancouver Island Transmission Project: Expected Energy Not Supplied Assessment" July 2007

[93] Wenyuan Li, "Probabilistic Reliability Assessment of Central Vancouver Island Transmission Project Expected Energy Not Served (EENS) Study for Vancouver Island Transmission Reinforcement Project Part I: Reliability Improvements due to VITR" December 2005

[94] Wenyuan Li, "Expected Energy Not Served (EENS) Study for Vancouver Island Transmission Reinforcement Project Part II: Comparison between VITR and Sea Breeze HVdc Light Options" December 2005

[95] Exhibit 12, Nalcor, "Forced Outage Rates Summary Sheet", June 2006

[96] R. Billinton and R. N. Allan, Reliability Evaluation of Engineering Systems: Concepts and Techniques, Plenum Press, New York, 1992

[97] Wenyuan Li, "Probabilistic Reliability Assessment of Central Vancouver Island Transmission Project: Expected Energy Not Supplied Assessment" July 2007

[98] Wenyuan Li, "Probabilistic Reliability Assessment of Central Vancouver Island Transmission Project Expected Energy Not Served (EENS) Study for Vancouver Island Transmission Reinforcement Project Part I: Reliability Improvements due to VITR" December 2005

[99] NERC's Generation and Transmission Reliability Planning Models Task Force, "Generation and Transmission Reliability Planning Models Task Force Final Report on Methodology and Metrics", September 2011

[100] R. Billinton and R. Allan, Reliability evaluation of power systems, 2nd Edition, Plenum Press, New York, 1996.

for region and total annual electric energy consumption in a particular period. It was confirmed by Nalcor Energy that there were no studies conducted on system EUE and associated risk costs therefore risk costs were not factored in the economic analyses.

3.11 Conclusions and Key Findings

Available documentation for reliability assessment performed by Nalcor has been reviewed by MHI. The adequacy criteria of 2.8 hours/year of loss of load expectation for resource planning, which considers both generation resource availability and economics, appears reasonable when compared to practices of other operating utilities[101].

The HVdc system together with the overhead transmission line and submarine cable will have pole and bipole outages, and in some cases, for extended periods of time. The amount of plant installed to cover off risk factors and contingencies (for example, overload rated submarine cables with a spare cable, converter station pole overload, redundant auxiliary supplies, etc.) will mitigate these risks through appropriate design and specification.

The source documents for the development of probabilistic reliability models for the proposed Labrador-Island Link HVdc system are available but have not been updated with recent project definition parameters such as marine crossing details, length and reliability parameters of the transmission line, and configuration of the HVdc converter stations. The procedures and methodologies proposed by PTI for the development of the HVdc system reliability model are still valid and can be used for modeling the proposed Labrador-Island Link HVdc system with appropriate modifications such as HVdc converter station design layout, spare cable and SOBI crossing details, and transmission line design criteria.

[101] Exhibit 106, Nalcor, “Technical Note: Labrador-Island HVdc Link and Island Interconnected System Reliability”, October 2011

Key findings of MHI's review of the reliability studies are as follows:

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

- Probabilistic adequacy studies, including considerations related to transmission for comparison of the reliability of the two options, have not been completed by Nalcor. This is a gap in Nalcor's practices as various Canadian utilities including Manitoba Hydro, BC Hydro, Hydro Quebec, and Hydro One in Ontario have adopted these probabilistic methods for reliability studies for major projects. Probabilistic reliability methods utilize standard terms and indices such as Loss of Load Expectation, or Expected Unserved Energy, and make the risk analysis results plainly understandable in terms of dollars and/or loss of load.

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